

**HB**

**325**

**HFIN**

**FILE**

TONY KNOWLES, GOVERNOR

## DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

February 13, 1996

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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 appear 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.

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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 resources 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).

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3. The legislation would apparently circumvent any negotiated agreements (unit agreements or litigation settlement agreements or HIB 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 IIB 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

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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 bpd 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.<sup>1</sup> 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

<sup>1</sup> 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).

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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 IIB 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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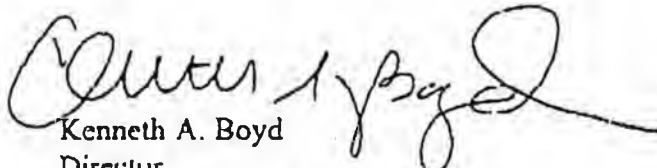
37. The Goldsmith study predicted numerous jobs being created by such royalty relief. According to the white paper, the Goldsmith study predicts that the State will add 27 additional State government jobs during the development phase and 10 additional State government jobs during the field life. It is 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 as Schrader Bluff, the easiest, most effective change should be through a simple amendment to the existing AS 38.05.180(j) provisions.

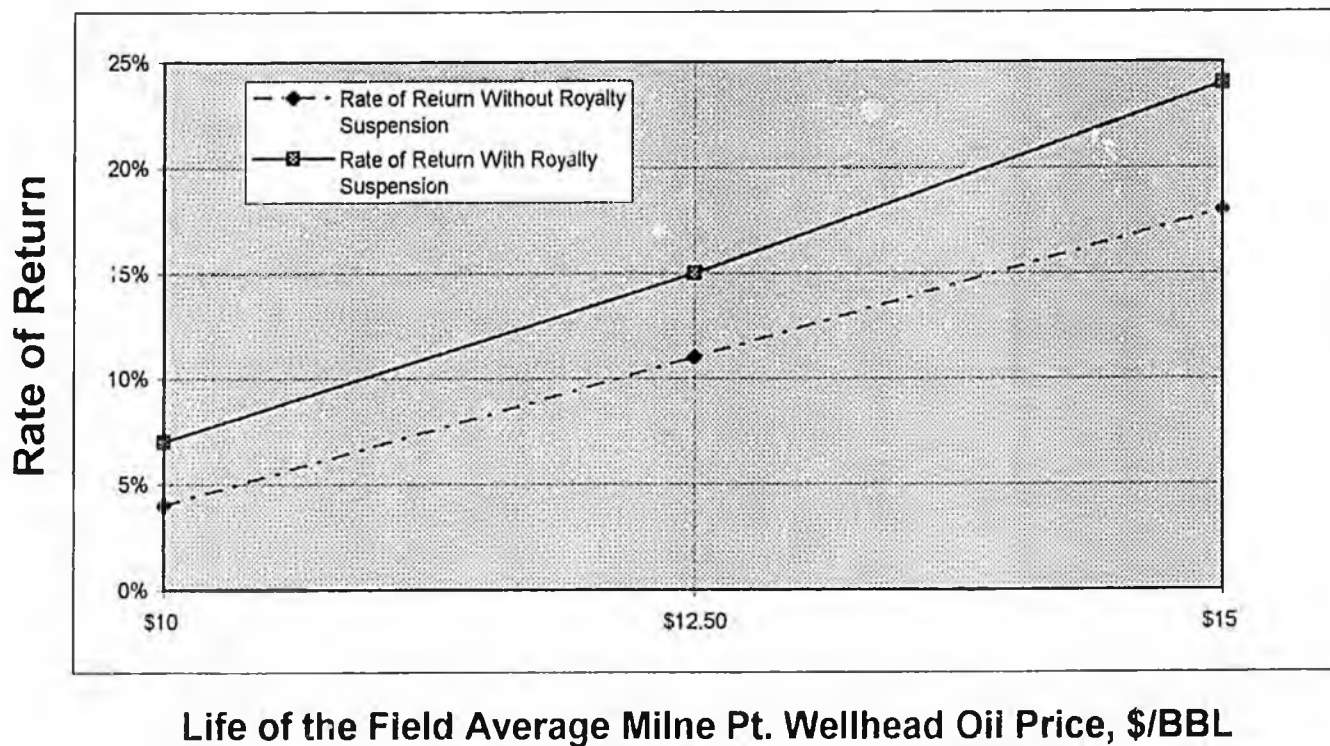
This letter covers numerous issues; nevertheless, if you have further questions (or answers), please don't hesitate to contact me.

Very truly yours,

  
Kenneth A. Boyd  
Director  
Division of Oil and Gas

2/12/94  
JF  
AT

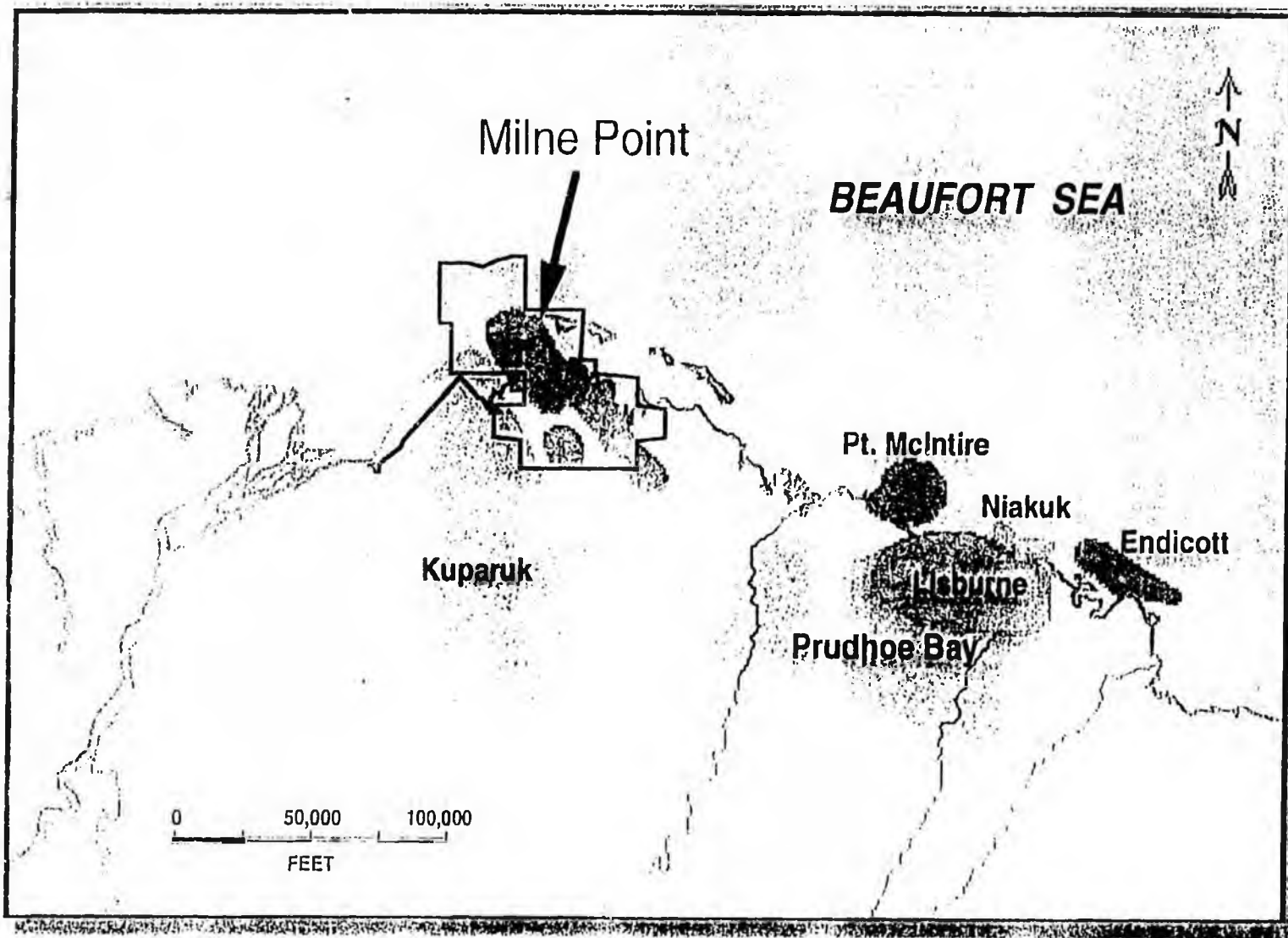
### Rate of Return at Various Life of the Field Average Oil Prices OXY Per-Well Economics



# WHO IS OCCIDENTAL OIL AND GAS CORPORATION?

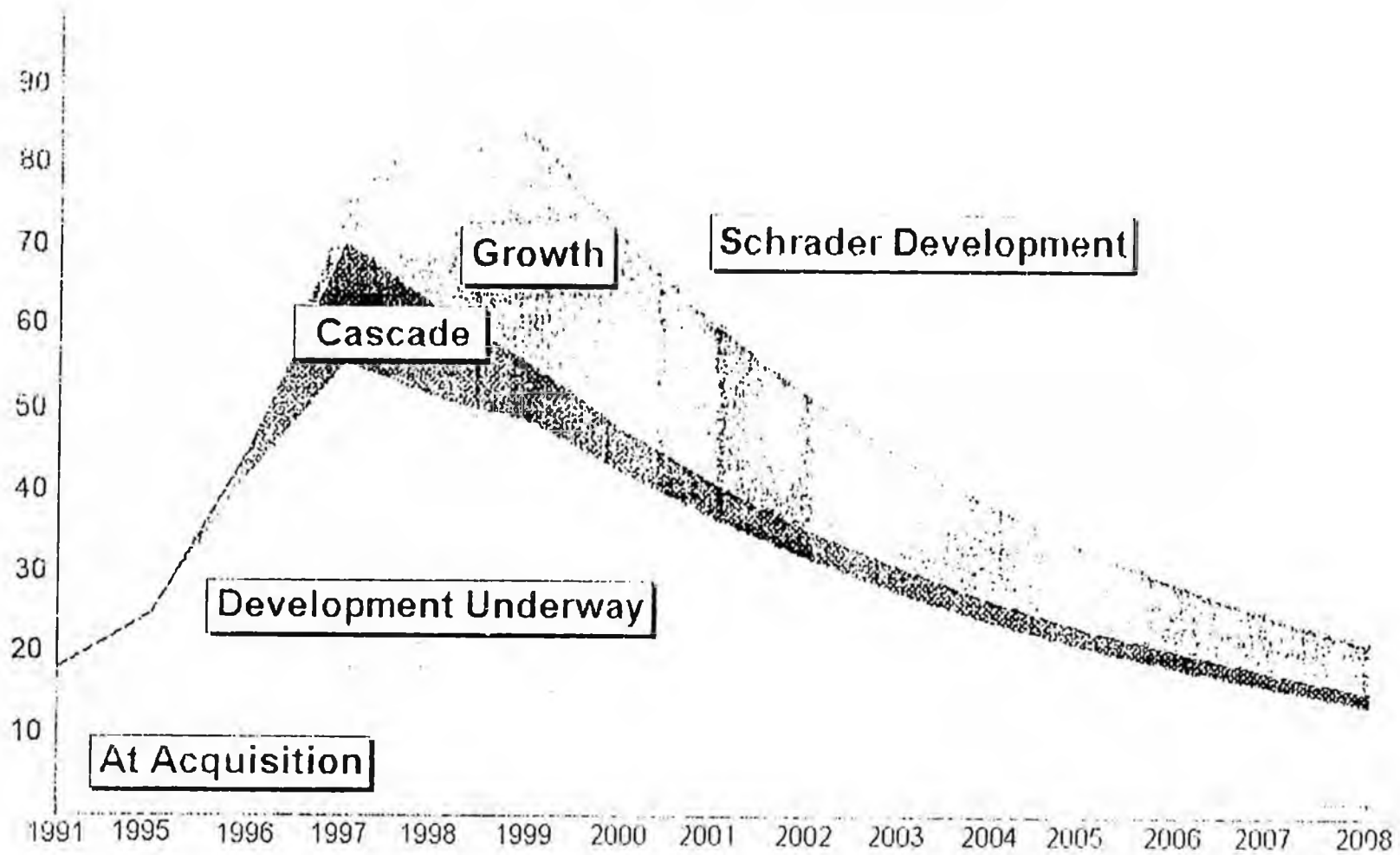
- *Oil & gas part of Occidental Petroleum Corporation*
- *Large independent in the US, no refining or marketing operations*
- *No financial interest in TAPS*
- *Operator of Heavy Oil properties in California*
- *The last original owner in Milne Point Unit with around 9% WI*

ATTACHMENT-1  
2/8/96

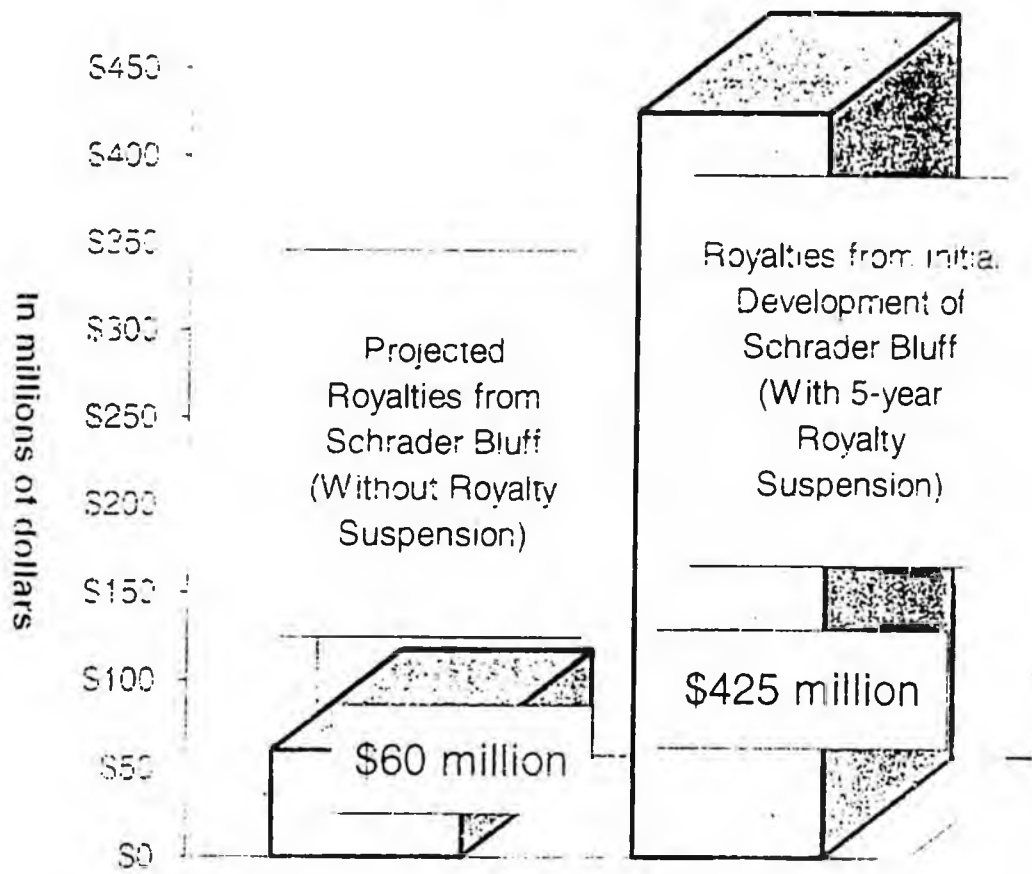


North Slope Fields and Milne Unit Outline

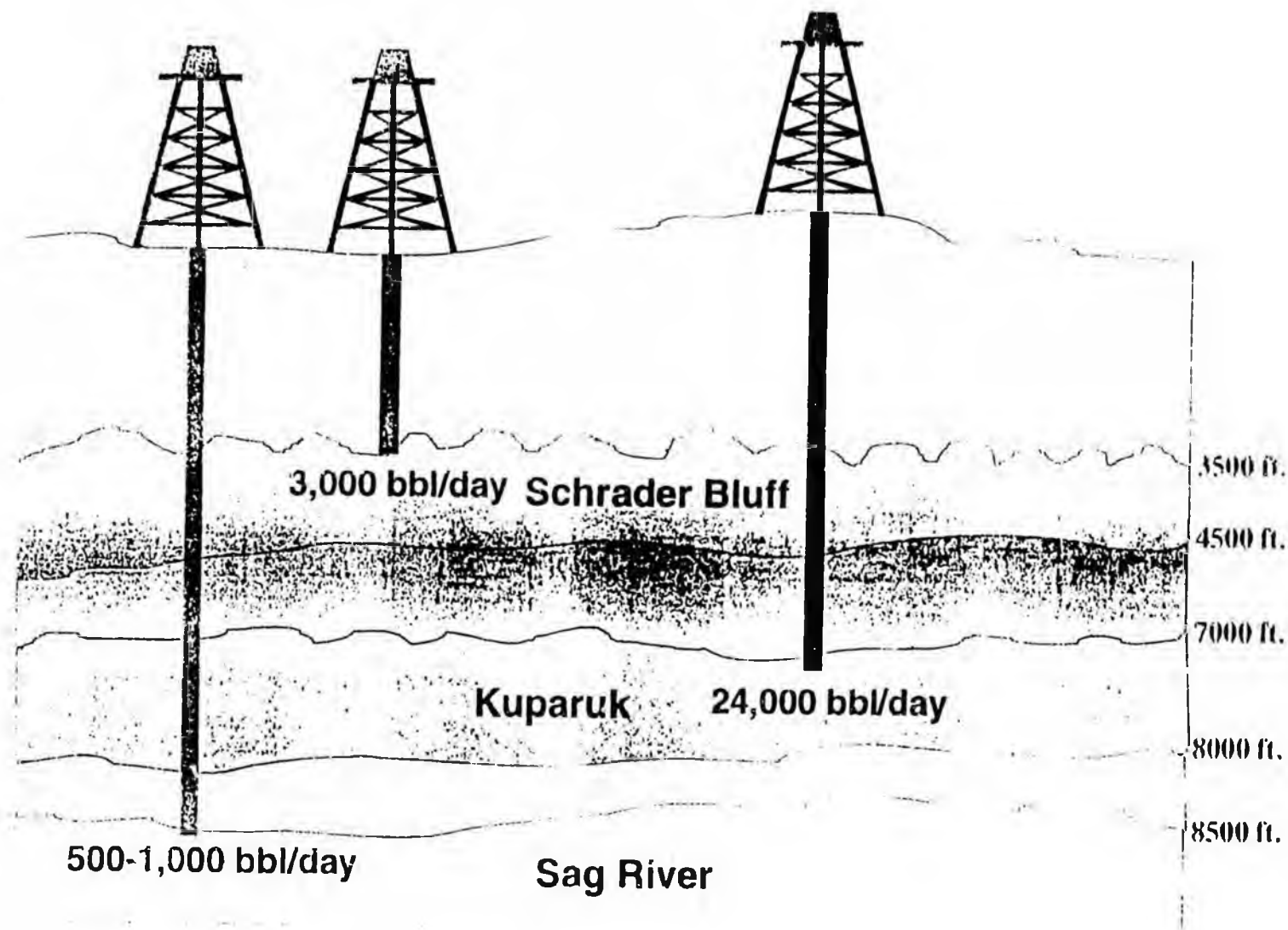
# Milne Point Production Profile



## Two Paths for Schrader Bluff

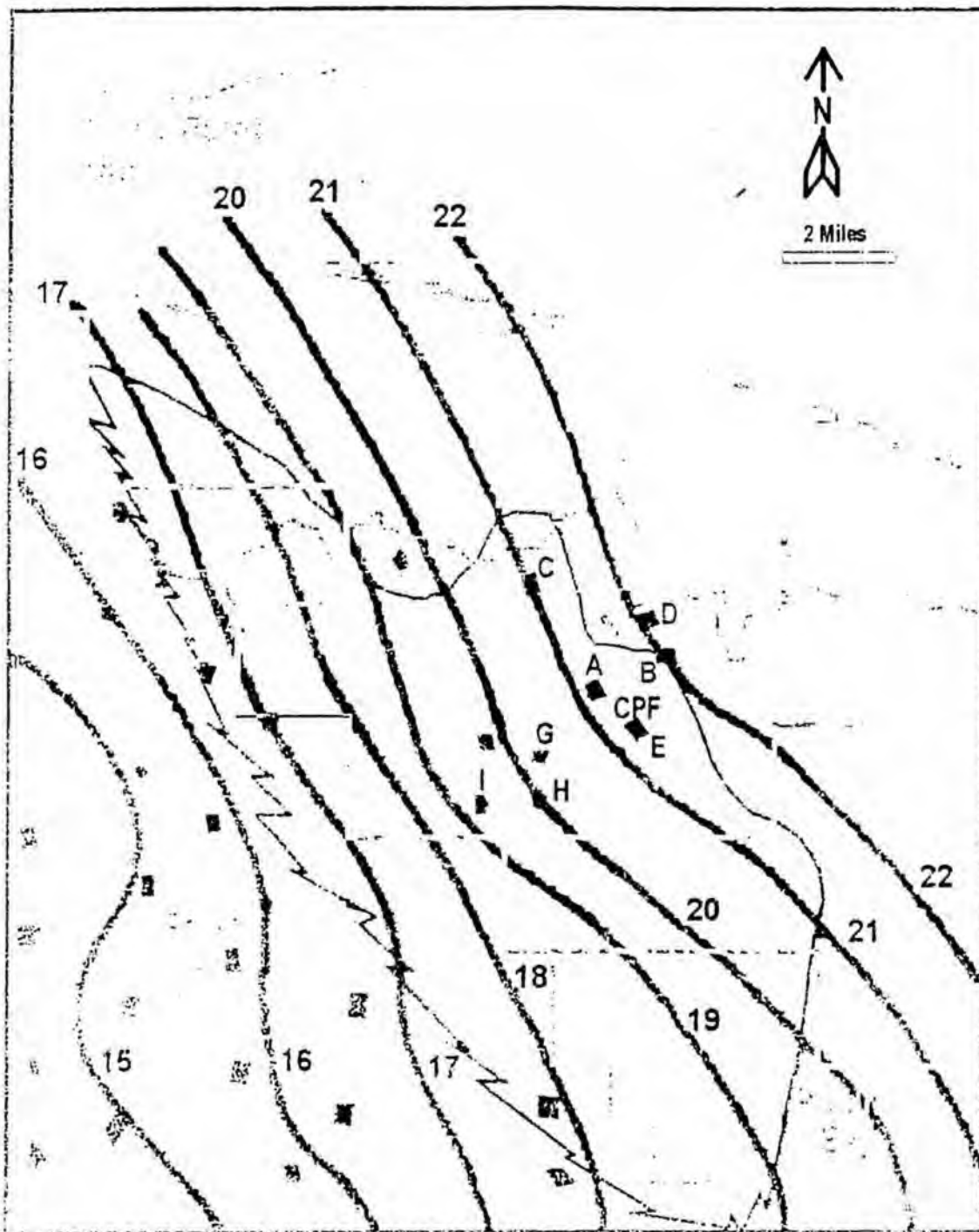


# *Production Formations at Milne Point*



# What is "heavy oil"?

- Low gravity
- Thick
- Produces slowly over a long period of time
- Disadvantaged in market place
- Capital intensive
- A focus of current debate on oil and gas incentives

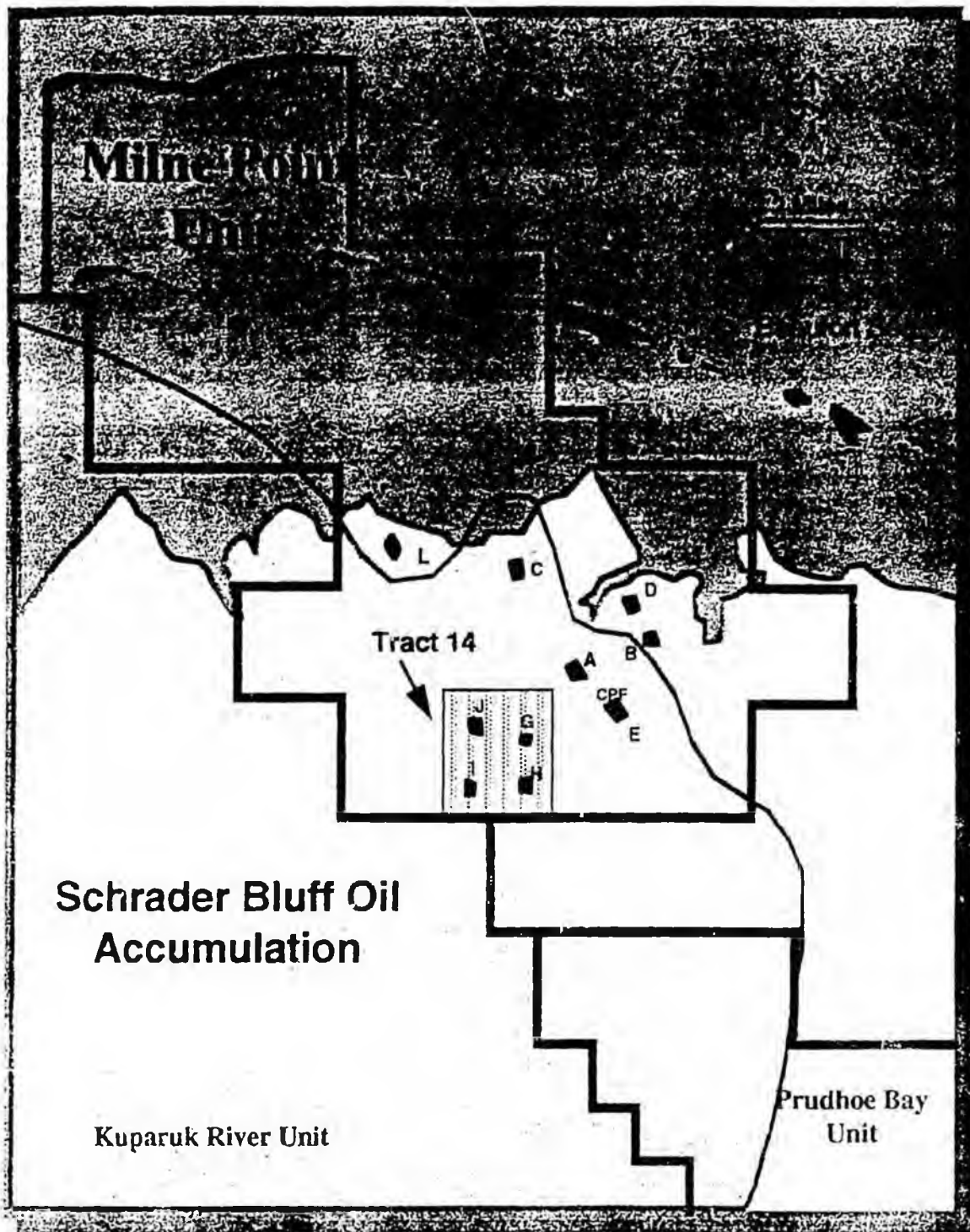


**SCHRADER BLUFF**

O Sand  
 API Gravities

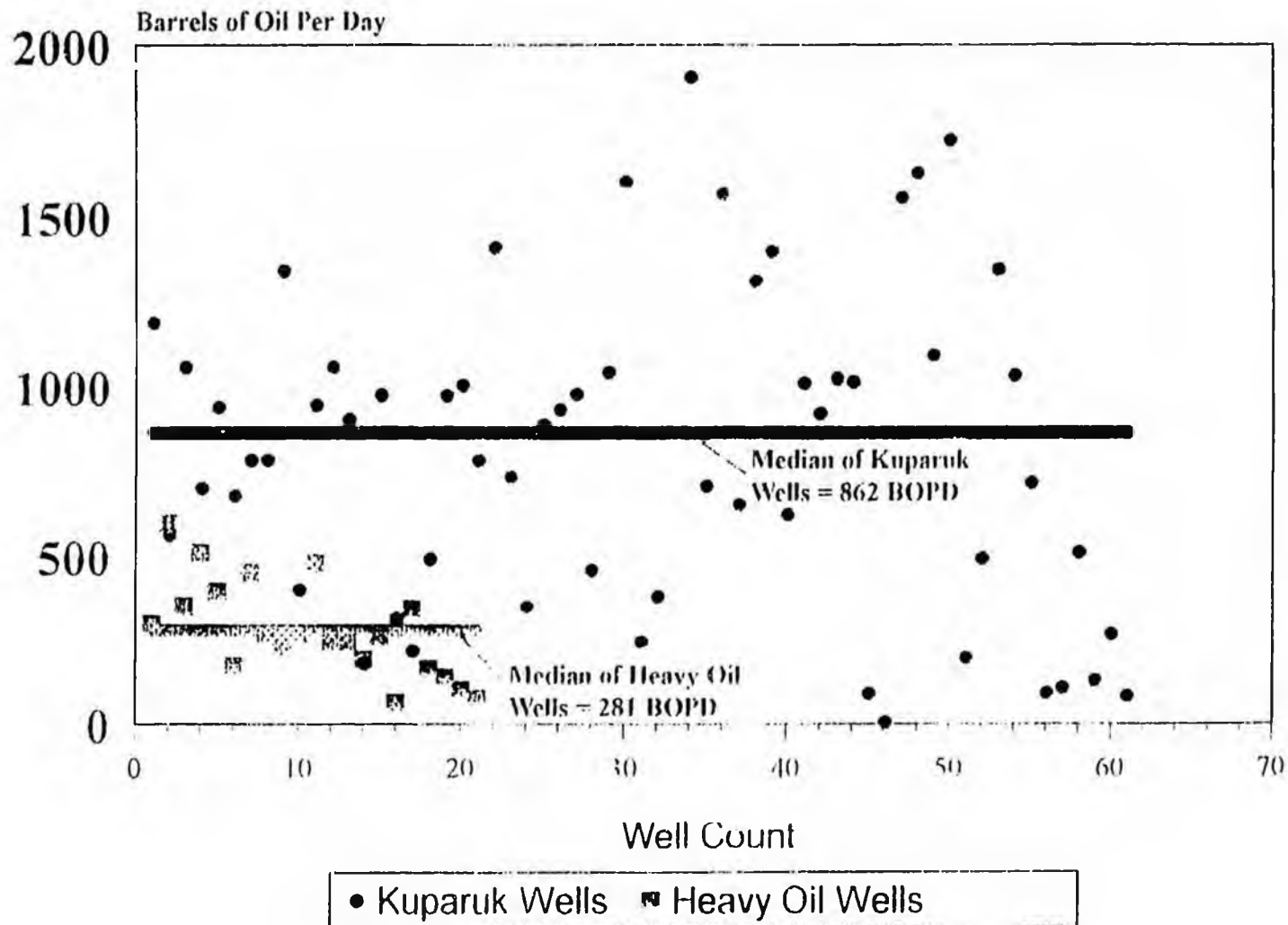
# Previous Heavy Oil Development

- *Spent \$135 Million on 13 wells and related facilities*
- *Average producing rate = 250 BOPD per well*
- *Recovery = 0.8 million barrels before abandonment in 1986*
- *Total Capital Investment = \$169/Barrel*
- *Uneconomical*



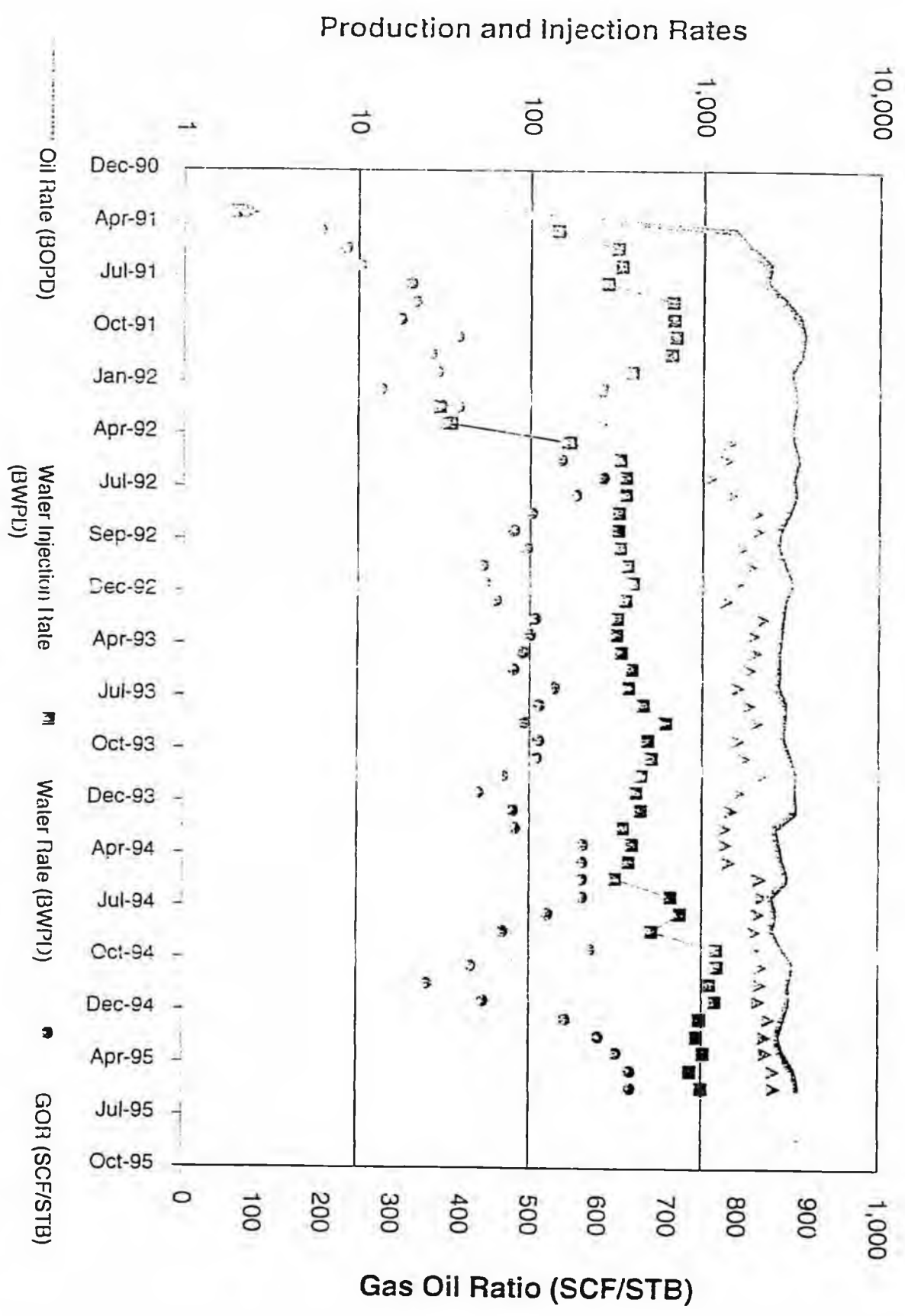
Schrader Bluff Oil Accumulation

## *Heavy Oil Wells Have Much Lower Initial Flowrates*



# Schrader Bluff Tract 14

## Monthly Average Production and Injection History



# Previous Heavy Oil Experience

*Spent a minimum of \$126 Million on 22 wells, pads, etc.*

*• Average producing rate = 275 BOPD per well*

*• Expected Recovery = 13.5 Million Barrels*

*• Total Investment = \$9.30/BBL*

*• Uneconomical*

Source: SPE 30239, "Milne Point Schrader Bluff: Finding the Keys to Two Billion Barrels" (2001). Reserves determined from decline curve analysis.

SCHIRADER BLUFF TECHNOLOGY

HEAVY OIL TEST BED  
HIGH ANGLE FRAC PACKING  
ELECTRIC SUBMERSIBLE PUMP  
HEAT TRACE TECHNOLOGY

OIL TO  
PROCESSING

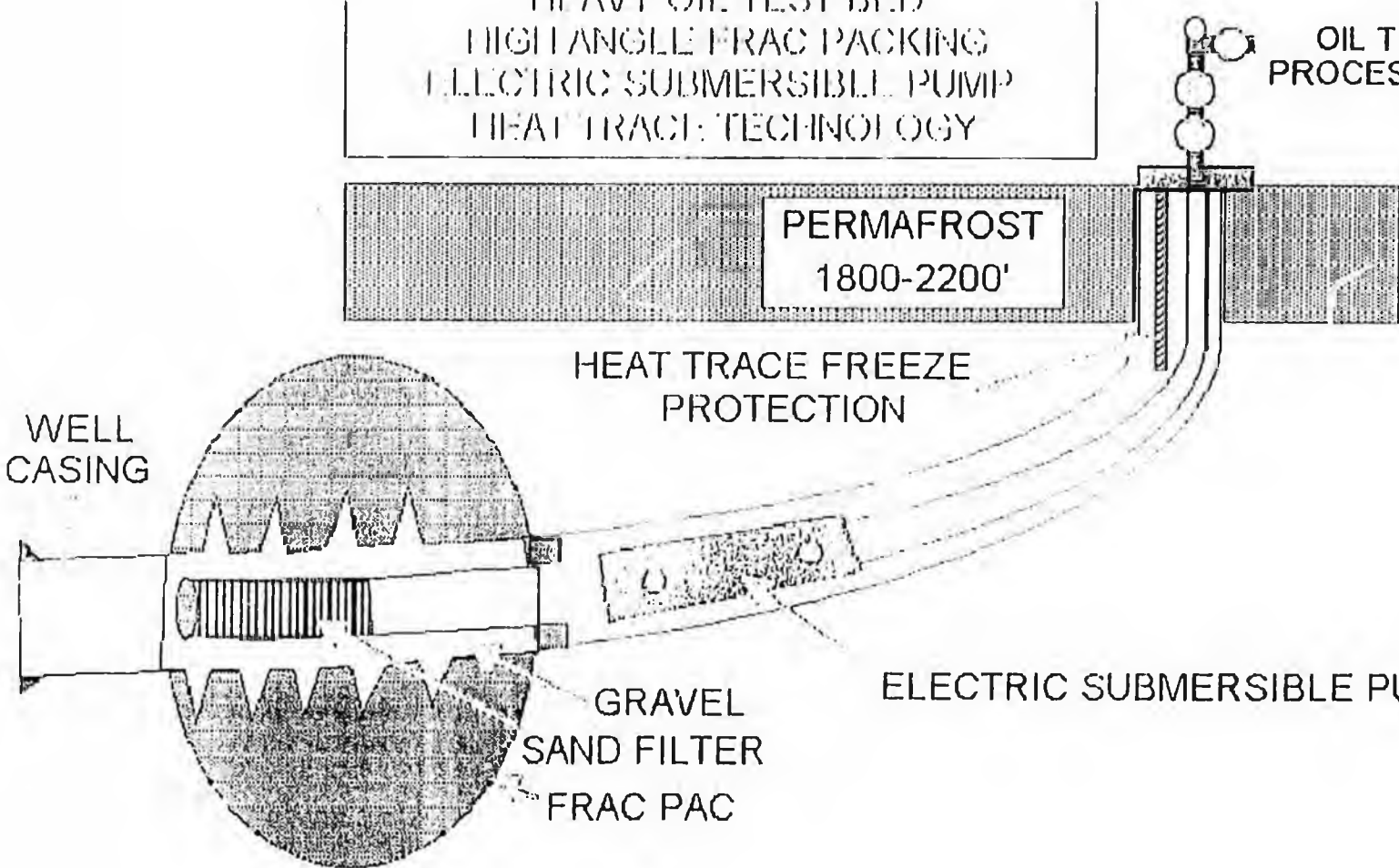
PERMAFROST  
1800-2200'

HEAT TRACE FREEZE  
PROTECTION

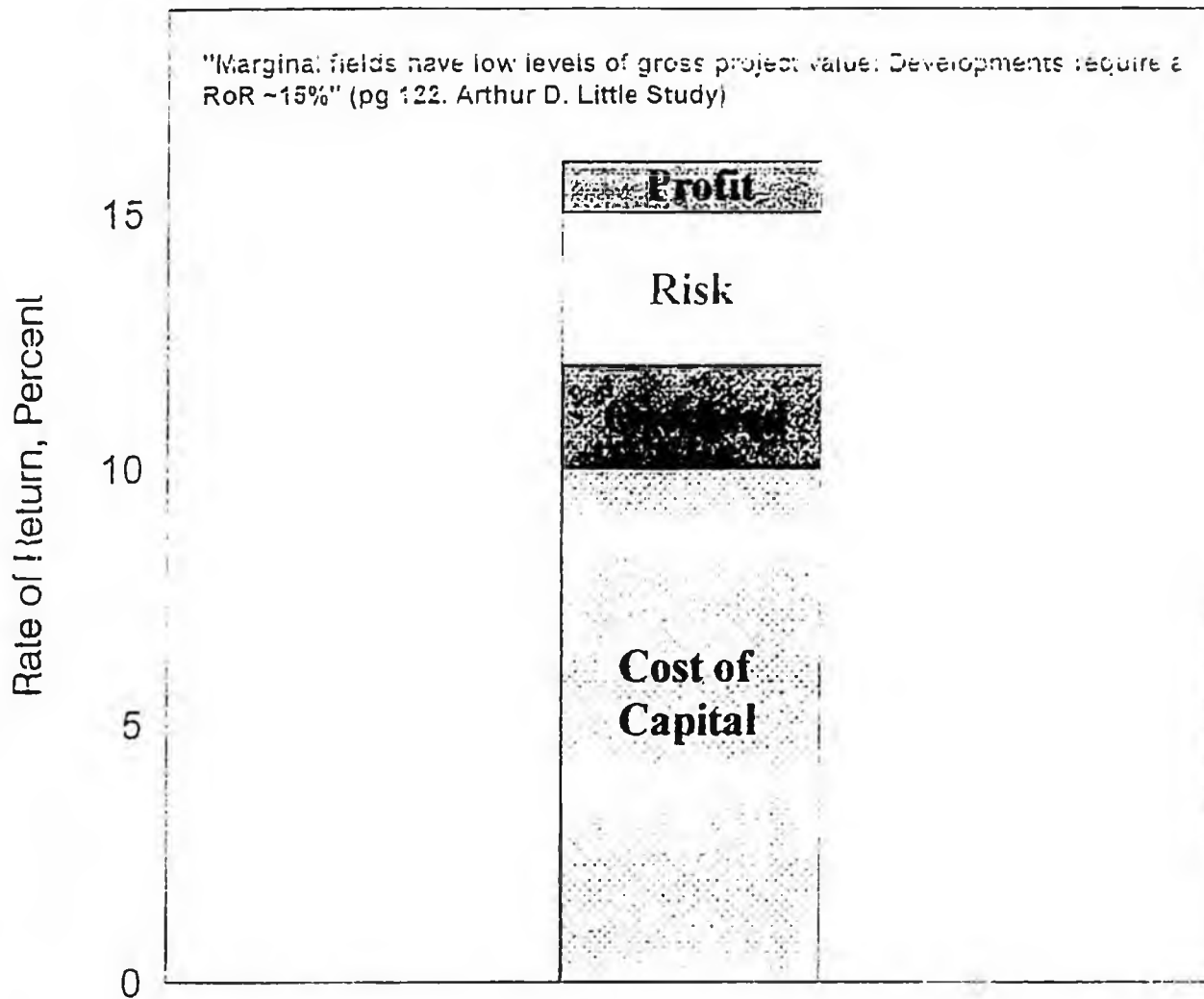
WELL  
CASING

ELECTRIC SUBMERSIBLE PUMP

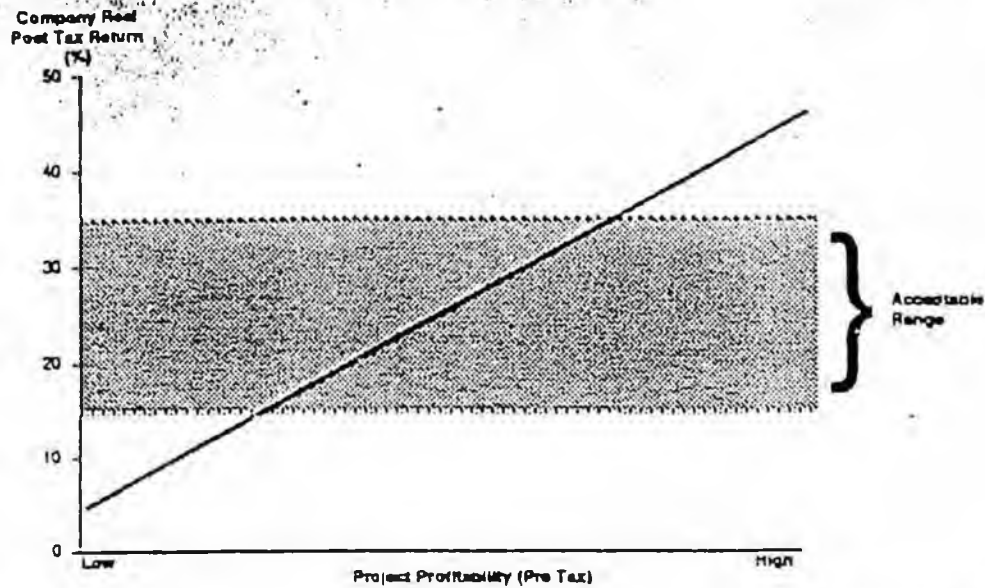
GRAVEL  
SAND FILTER  
FRAC PAC



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



## Conventional fiscal systems are fiscally inefficient



Arthur D Little

HE 471/1986

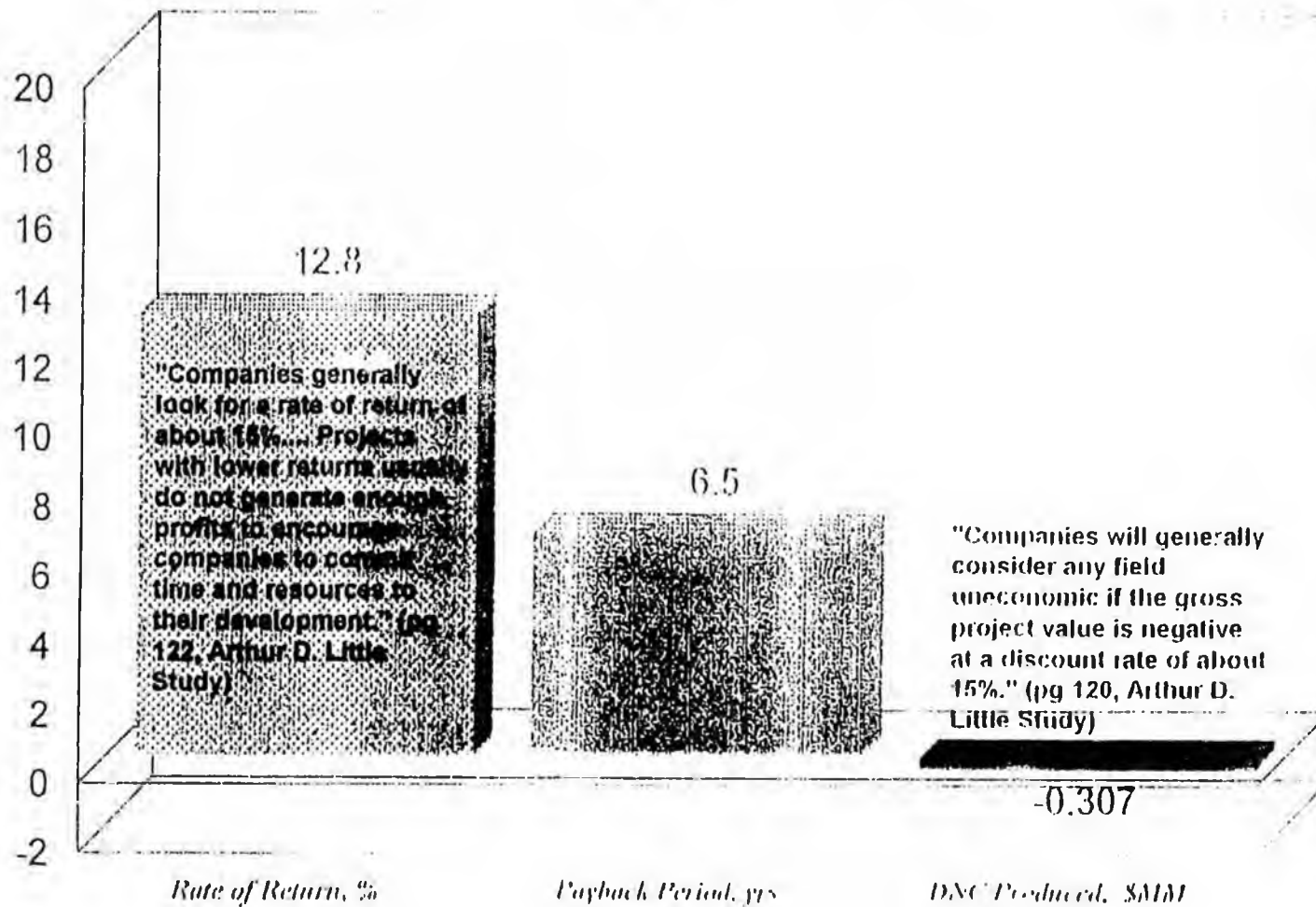
11

## Conventional fiscal systems are fiscally inefficient:

- Under a traditional petroleum agreement (with fixed royalty and income tax rates under a licence agreement or fixed cost and profit sharing under a production sharing contract) the total government take and the oil company profitability change considerably with the characteristics of the discovery (size and development cost) and with oil prices.
- This type of system is "fiscally inefficient" and has fallen into disfavour following the oil price fall in 1986 and a worldwide trend towards smaller field discovery sizes.
- In a fiscally inefficient system:
  - Smaller and higher cost fields will not be developed as the profitability is too low to attract oil companies.
  - Larger and least expensive fields will generate excessive profits for the companies: the government take will be lower than it has the potential to be.
  - Similar effects will be experienced if oil prices are unexpectedly high or low.
- Thus, uniform fixed rate fiscal systems produce non-uniform results which are economically discriminatory:
  - It is important to "tailor" the contractual terms so that the conditions offered are attractive both for significant and for small discoveries and so that the long term interests of host country and the investors are protected, for example, in the case of wide variations in crude oil prices.

# Typical Heavy Oil Well Economics

Based on the 5 best wells to date in Tract 14



# What are we proposing?

HB 325 by Representative Green

- Applicable to heavy oil production as defined by 26 U.S.C. 613A(c)(6)(F)
- Applicable only to the Alaska North Slope
- Suspension of royalty payments for each new well for the:
  - first five years
  - first 500 barrels of oil per day
- A simple, automatic process

# Suspension Incentives in Other Jurisdictions

- Texas
  - high-cost gas (10 year exemption)
- Utah
  - wildcat wells (first 12 months)
  - development wells (first 6 months)
- Oklahoma
  - horizontal wells (until payout)
  - enhanced oil recovery projects (until payout)
- Montana
  - horizontal wells (first 18 months)
- Mississippi
  - discovery wells (first 5 years)
  - re-activated wells (first 3 years)
- Kansas
  - tertiary projects (for life of project)
  - shallow wells (for life of project)
  - discovery wells (first 12 years)
- Arkansas
  - discovery wells (first 5 years)

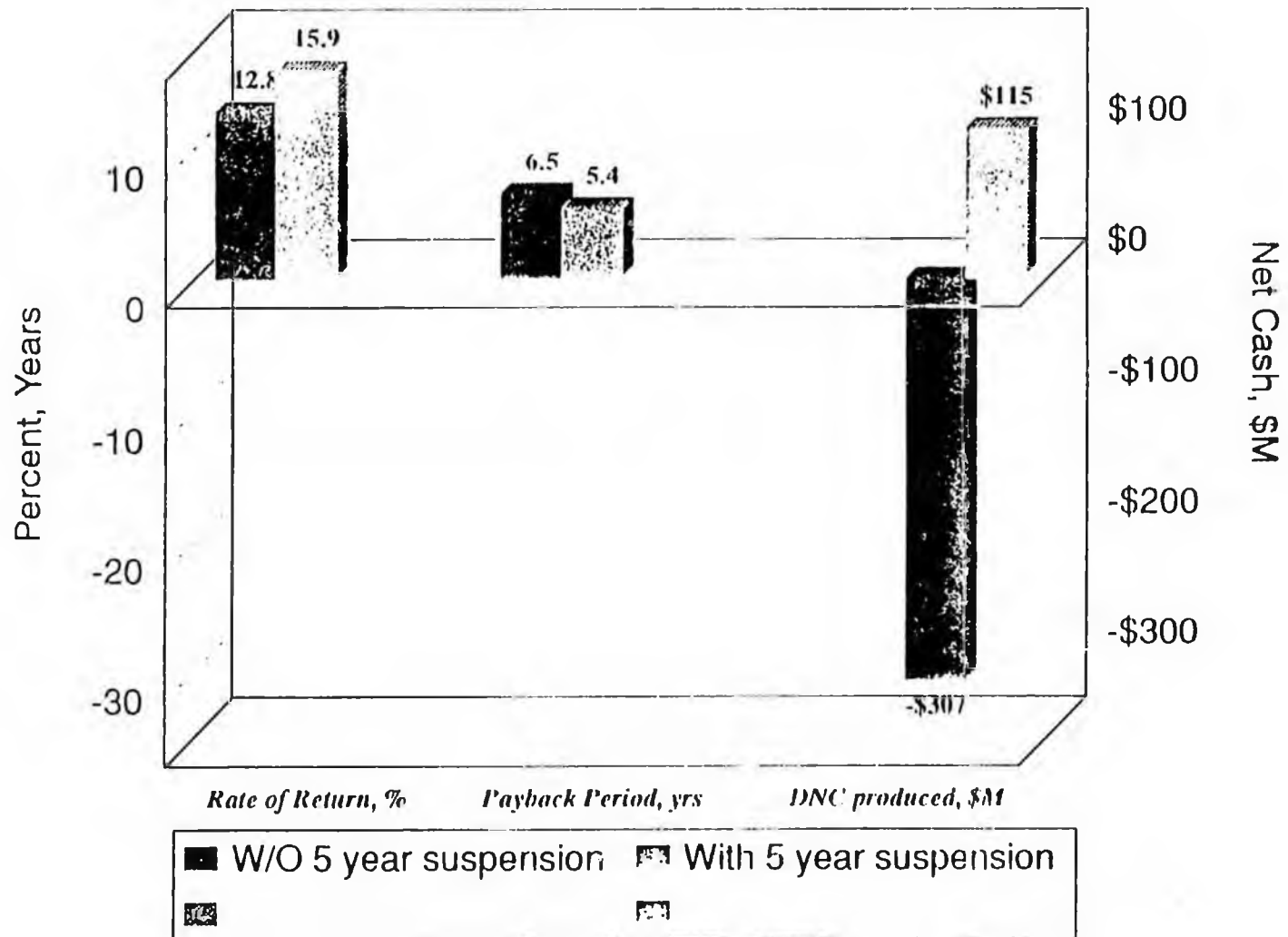
# Texas "High - Cost Gas" Incentive

## Benefits Identified

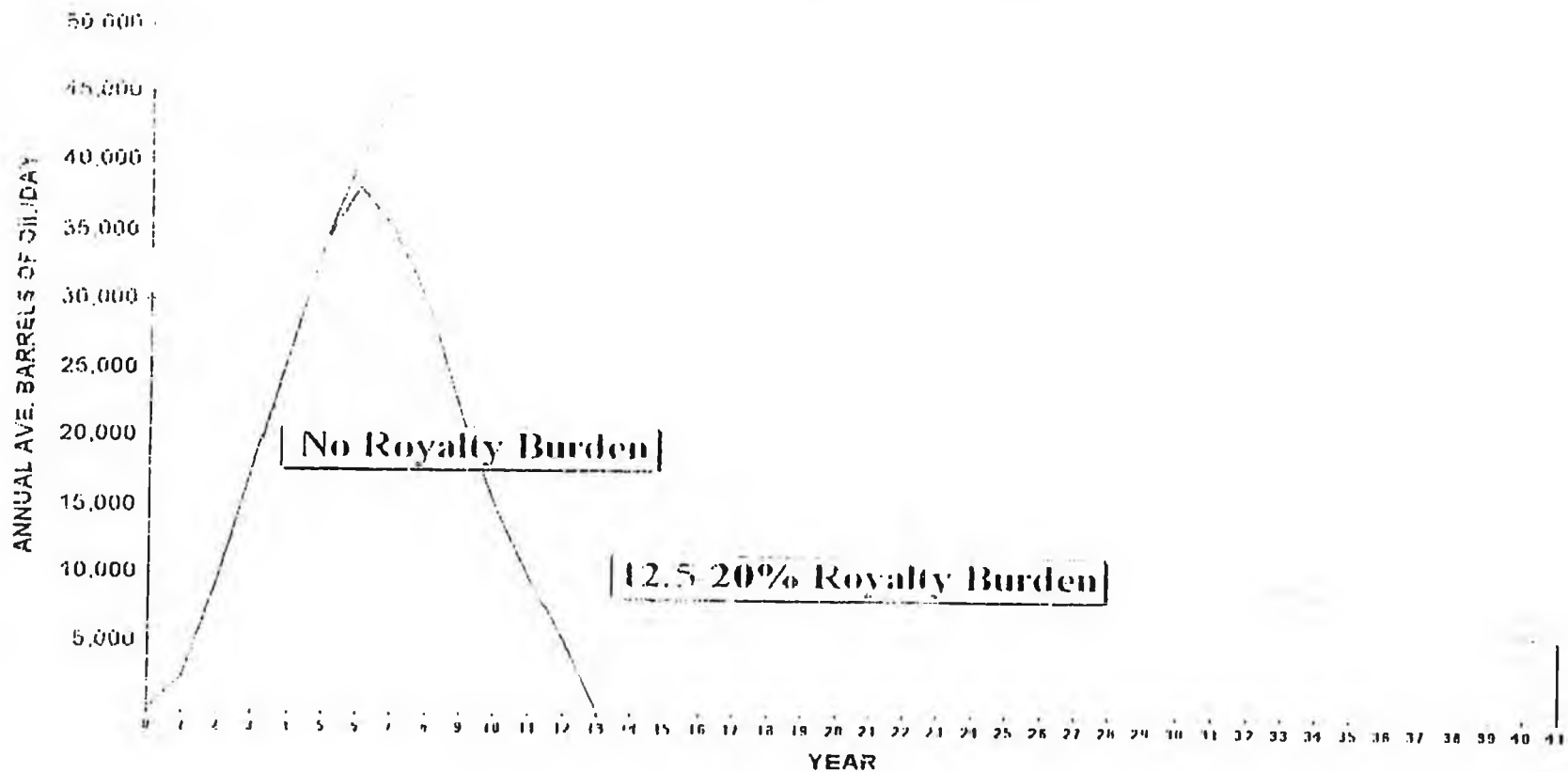
- 400% increase in the number of wells
- \$4.122 Billion more in gas produced
- \$240 Million in sales tax revenues generated
- 104,000 employment years created
- \$12 Billion in additional economic value generated for Texas

Source: Texas Railroad Commission

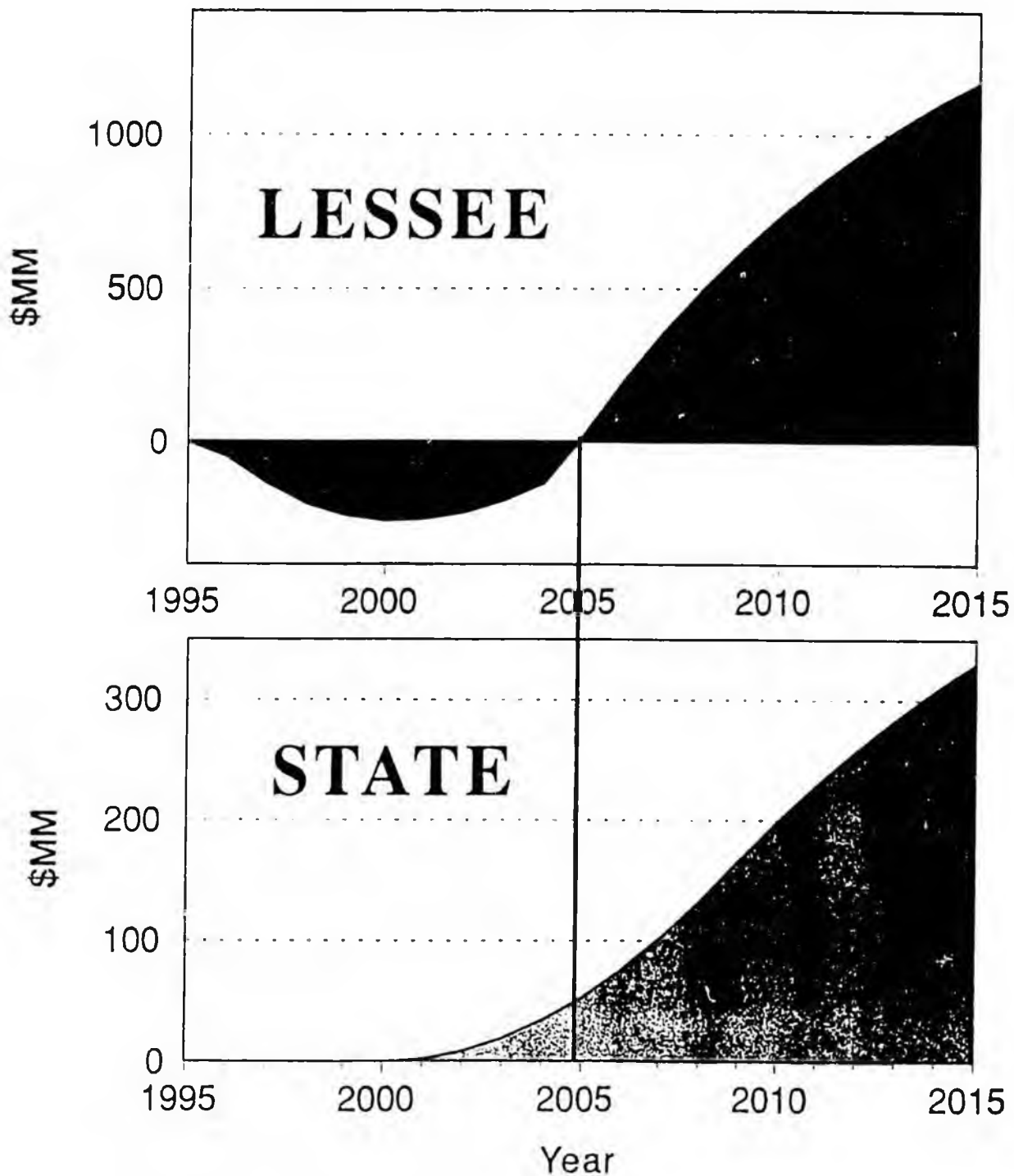
# The Effect of Royalty Suspension on Schrader Bluff Economics



ADDITIONAL PRODUCTION FROM HEAVY OIL,  
BY  
DEVELOPMENT YEAR



# Cumulative Cash Flows From Full Development



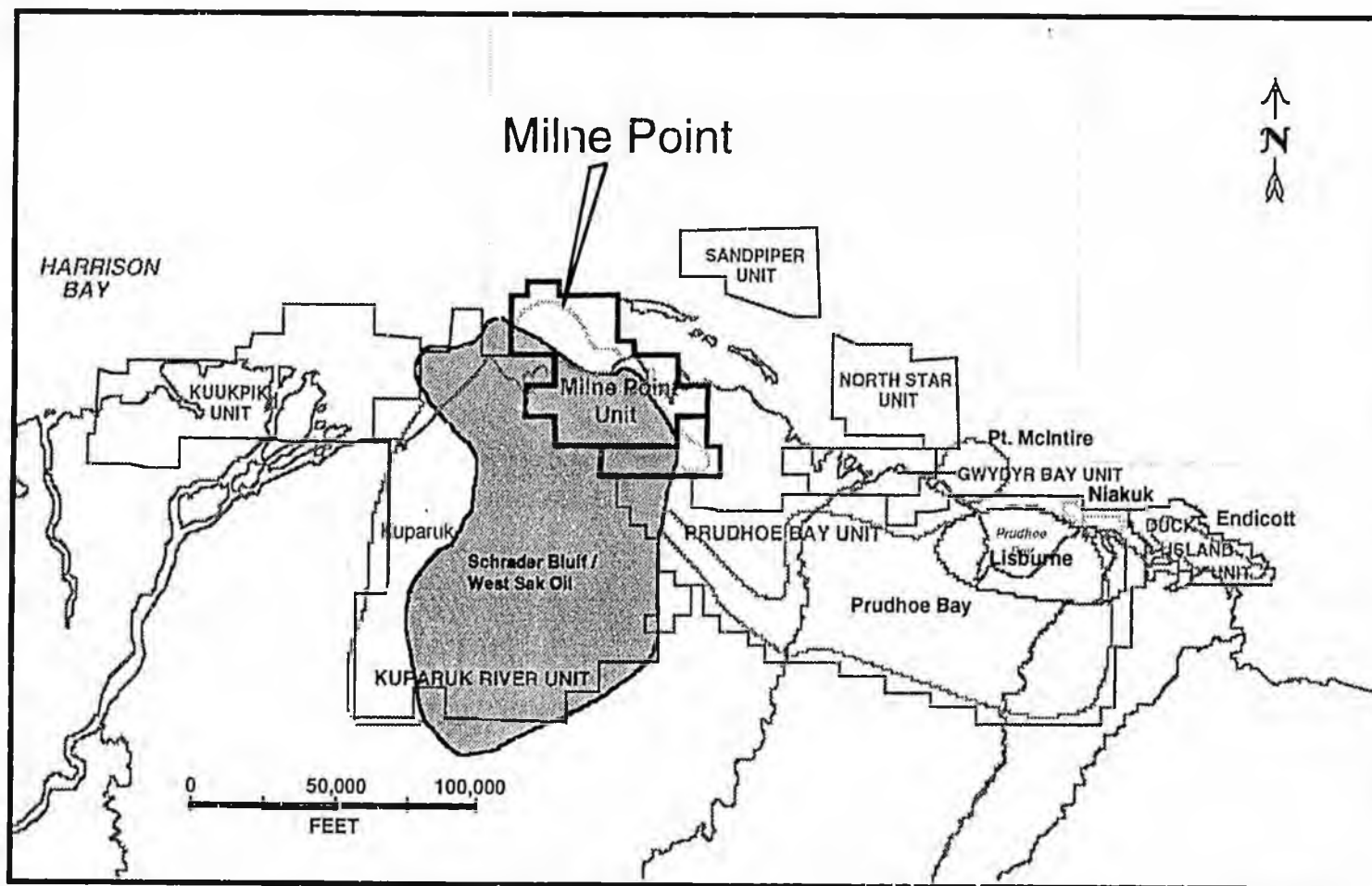
# Heavy Oil Potential at Milne Point

Presentation by BP Exploration (Alaska) Inc  
before the House Finance Committee

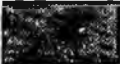
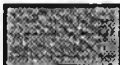


February 8, 1996

Attachment 2  
2/8/96

# North Slope Fields



# Schrader Bluff Heavy Oil Development

- 
- The map illustrates the Schrader Bluff Heavy Oil Development, divided into three main sections: KRU (Krug), CFP (Central Field Pad), and PBU (Pebble Bay Unit). The development is categorized into three stages: 'Development at Acquisition' (darkest shading), 'Development in Progress' (medium shading), and 'Future Development' (white). Existing pads are marked with solid black squares, while future pads are marked with squares containing a small black square. The map also shows a coastline to the west and a large shaded area to the north.
-  Development at Acquisition
  -  Development in Progress
  -  Future Development
  -  Existing Pad
  -  Future Pads

KRU

CFP

PBU

# Schrader Bluff Development History

- First production from pilot project in 1991.
- 16 producers and 5 injectors drilled.
- Low average initial well rate ~275 bpd.
- Completion technology advanced.
- Not commercially competitive.
- Development stopped '91.

Significant technical and commercial hurdles remain to be overcome

# MPU Schrader Bluff - Potential Program

1994

Drill Test Well

1995

Drill six "Test Wells"

?? - 1998 - ??

Potential Development

230 Wells

45,000 bpd Production

Key

Decisions

Determine viability and scope for '95 wells.

Demonstrate increased rate and reduce costs.

Establish viability of larger scale initial development.

## 1995 Schrader Bluff Development

- Objectives

- Reduce capital requirements and operating costs
- Increased production rates from new wells
- Reduce development uncertainty

- Progress - 1995 spend \$15,000,000

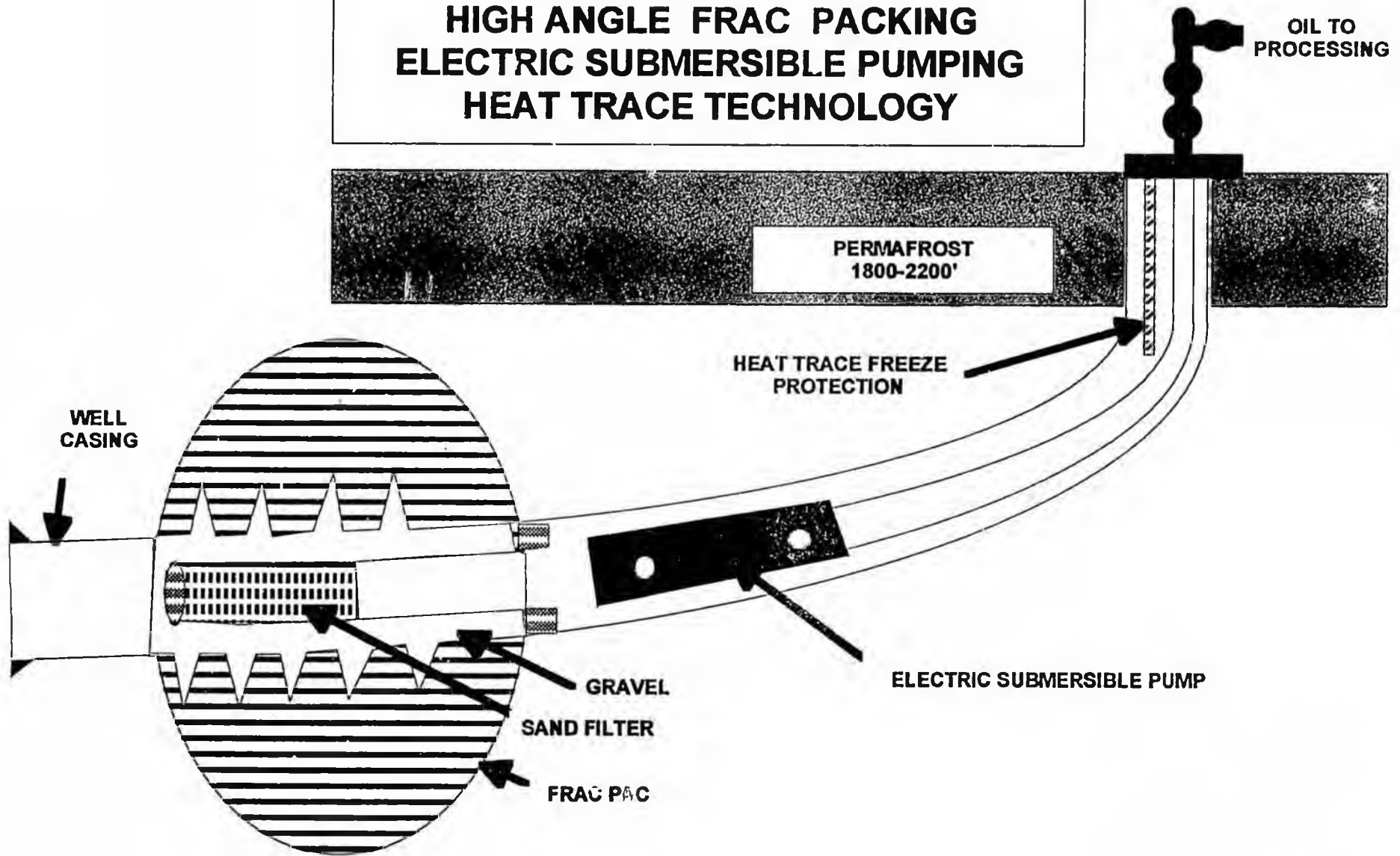
- Six wells drilled; completions in progress; not on production
- Three wells recompleted and on production
- Reservoir and facility technical studies initiated

- Results

- Drilling cost reduction demonstrated
- Completion cost remains problematic
- Improved submersible pump life realized
- Well performance and technical study results not yet available

**SCHRADER BLUFF TECHNOLOGY:**

**HEAVY OIL TEST BED  
HIGH ANGLE FRAC PACKING  
ELECTRIC SUBMERSIBLE PUMPING  
HEAT TRACE TECHNOLOGY**

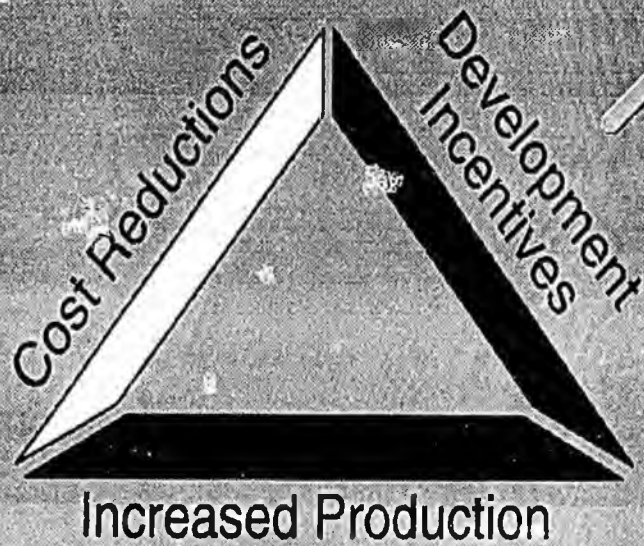


# Schrader Bluff Challenges

**Field  
Development**



**Compete  
Internationally  
for Funds**



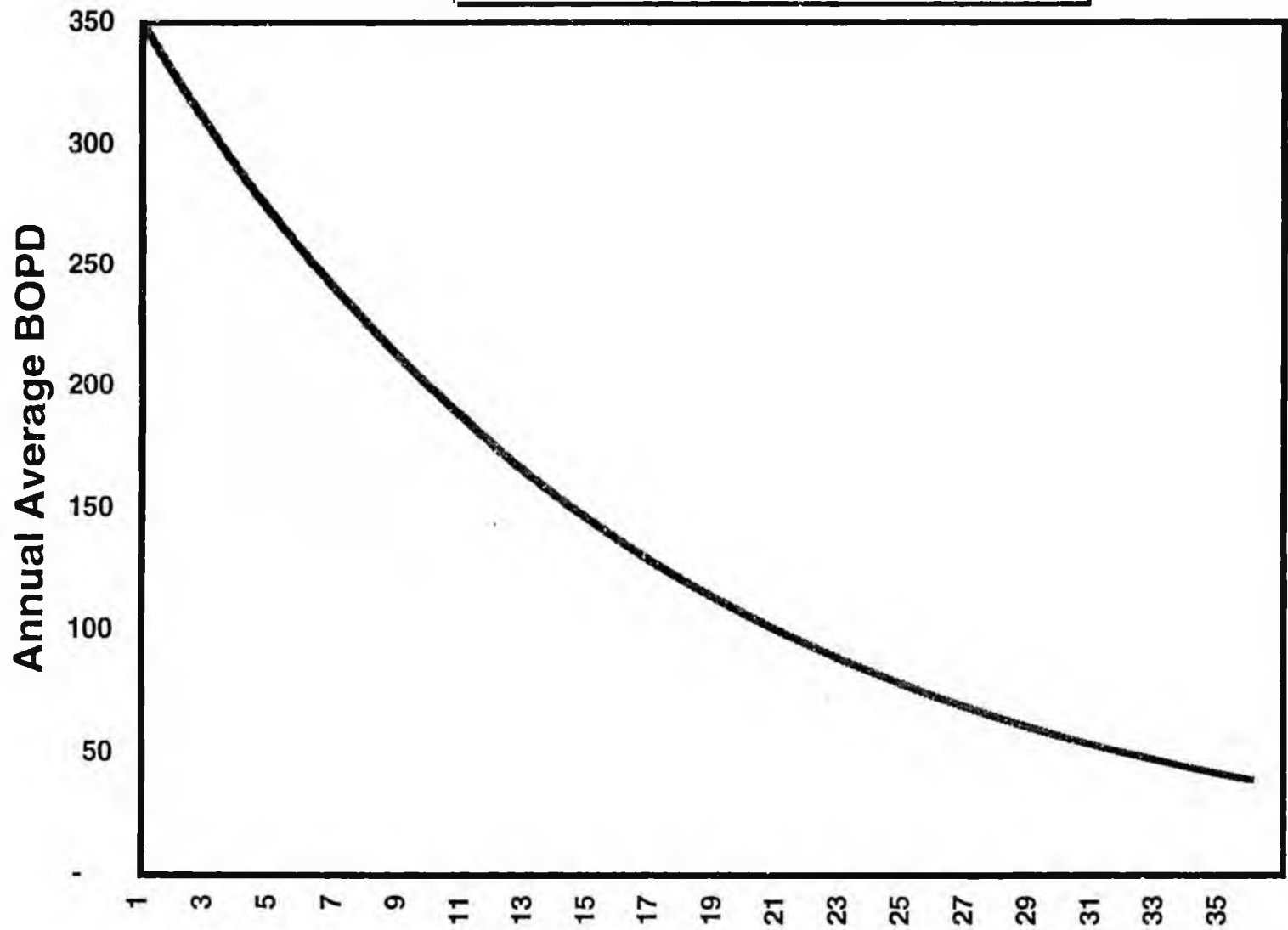
## The "Prize" at Schrader Bluff

- **2+ Billion barrels of oil in place**
- **Potential ultimate recovery - 200 to 800 million barrels**
- **Expansion to adjacent fields**

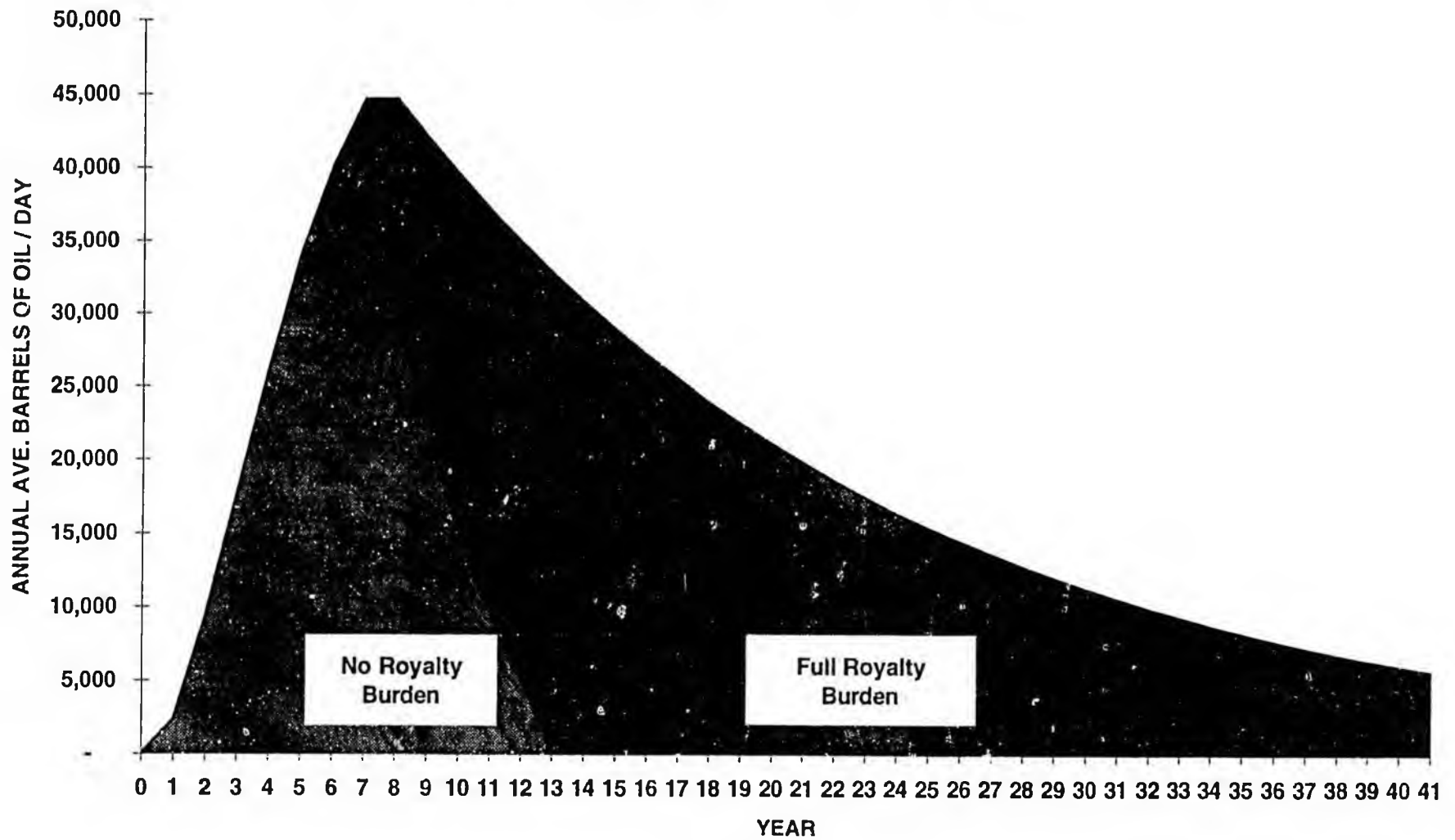
## **Heavy Oil Royalty Holiday (HB-325) Impact on Schrader Bluff Project**

- **Royalty holiday will:**
  - **Reduce investment uncertainty**
  - **Encourage investment**
  - **Send positive signal**
  - **Accelerate pace and increase development scope**
- **Time lag from incentive to start of investment is short**
- **Ultimate project scope remains uncertain**

**Schrader Bluff Typical Well  
Production Rate vs Time (years)**



**ADDITIONAL PRODUCTION FROM HEAVY OIL  
BY DEVELOPMENT YEAR**  
(300 million bbls recovered; 230 wells drilled over seven years)



## **The Risk of Project Development Delay**

- **Current development momentum is lost**
- **Economic benefits deferred / value lost**
- **Ultimate recovery placed at risk**
- **Project economics placed at risk**

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 "C" STREET, SUITE 1380  
ANCHORAGE, ALASKA 99503-5948  
PHONE: (907) 269-8784

January 30, 1996

The Honorable Bill Williams  
Alaska State Representative  
State Capitol, Room 128  
Juneau, Alaska 99801-1182

Dear Representative Williams:

You asked whether HB 207, passed last session, could be used to grant royalty relief for the production of "heavy oil." The division's short answer is yes. Nevertheless, because of the concerns expressed in the hearing on January 24 about the applicability of HB 207 to heavy oil production, the administration would support an amendment to HB 207 to provide explicitly that it applies to heavy oil production.

Subject to several provisions designed to protect the state's interests, HB 207 grants authority to the commissioner of the Department of Natural Resources to modify the existing royalty rate "to allow for production that would not otherwise be economically feasible" for any one of three types of oil or gas pools. In essence, the three are:

1. To allow production from an oil or gas pool that has been delineated, but has not previously produced ("New Pool").
2. To prolong the economic life of an oil or gas pool as costs per barrel or barrel equivalent increase ("Declining Pool").
3. To reestablish production from a shut-in oil or gas pool ("Shut-in Pool").

For purposes of HB 207, heavy oil production is no different from any other type of oil production. In other words, HB 207 would apply whether the oil production consisted of heavy, medium, or light production. If a company wished to produce heavy oil from a Shut-in Pool, it could be granted royalty relief under HB 207. For example, heavy oil production from ARCO's portion of the Schrader Bluff pool (which ARCO calls West Sak) that has been shut-in could be granted royalty relief. The same would be true for heavy oil production from a Declining Field or New Field.

Oxy and BP have a specific concern about whether heavy oil production from the Schrader Bluff pool within the Milne Point Unit could qualify under HB 207. Again the issue is not whether heavy oil production could qualify; rather it is whether the Schrader Bluff pool fits within one of the three types of pools listed in HB 207.

In the division's opinion, the Schrader Bluff pool does not meet the definition of a New Pool because the Schrader Bluff production has been sold. Arguably, the Schrader Bluff pool meets the definition of a Shut-in Pool. The Arco portion of the Schrader Bluff pool is currently shut-in. The Tract 14 pilot project for production from the Oxy and BP portion was shut-in from 1992 to 1994. If the production remains uneconomic, as the companies asserted in their testimony and the pilot project was stopped, the Schrader Bluff pool would clearly qualify as a Shut-in Pool.

Attachment 3  
218196

The Honorable Bill Williams  
January 30, 1996  
Page 2

The most applicable definition to the Schrader Bluff pool is the Declining Pool definition, number 2 above. First, granting royalty relief could "prolong the economic life of" the Schrader Bluff pool production. Second, the costs per barrel increase with heavy oil production. Most importantly, granting relief, assuming it was justified, would be consistent with HB 207's primary purpose "to allow for production that would not be otherwise be economically feasible." It appears that HB 207 could be applied to heavy oil production from the Milne Point Unit.

Nevertheless, some of the companies and representatives have expressed concern about the applicability of HB 207 to heavy oil production from the Milne Point Unit. To alleviate any concern about HB 207's applicability to the Milne Point Unit, the administration would support an amendment to HB 207 to make heavy oil explicitly included within the purview of HB 207. 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 the production from an oil pool containing heavy oil, defined as production with American Petroleum Institute weighted average gravity of 20 degrees or less; or

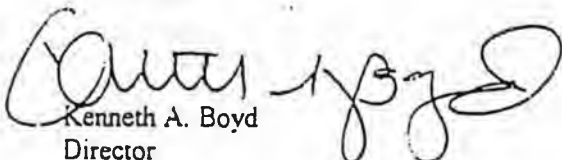
Such an amendment is preferable to HB 325 because it would subject any relief to the protection of the state's interests afforded by HB 207. Specifically, it would require a complete and thorough economic analysis of heavy oil royalty relief, which is lacking in HB 325. Indeed, no state agency has been given the detailed backup data that presumably supports the economic assertions contained in the white paper prepared by BP and Oxy. HB 207 would also provide for public and legislative comment before any relief is granted. Finally, it would allow any relief granted to be conditioned to change if the bases upon which the relief is granted change.

By passing HB 207, the legislature adopted a consistent policy that would treat all players fairly and equally. HB 207 allows for "fiscally efficient" royalty terms. HB 325 is not fiscally efficient because it is not sensitive to profitability. It reduces the state's royalty without a showing of necessity by the companies or a guarantee of anything in return to the state for granting relief. Despite the companies' contrary protestations, they can have certainty of relief under HB 207 before making any investment.

Undeniably, HB 207 is not as administratively simple as HB 325 because it requires a complete review. The long debate over HB 207 last session convinced me that although both the legislature and the governor want expedited development of Alaska's oil and gas resources, they want this done with proper scrutiny. This scrutiny, clearly present in HB 207, is lacking in HB 325.

I hope this information is helpful to you. If you have any further questions, please feel free to call me.

Sincerely,

  
Kenneth A. Boyd  
Director

Adopted  
Amendment 3

Page 2, after line 30

insert "(F) for purposes of defining field costs in this subparagraph, field costs include ~~the~~  
lease or ~~costs~~ outlined in AS 38.05.180(f)."  
unit expenses

Hose

# LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES  
LEGISLATIVE AFFAIRS AGENCY  
STATE OF ALASKA

(907) 465-3867 or 465-2450  
FAX (907) 465-2029  
Mail Stop 3101

130 Seward Street, Suite 409  
Juneau, Alaska 99801-2105

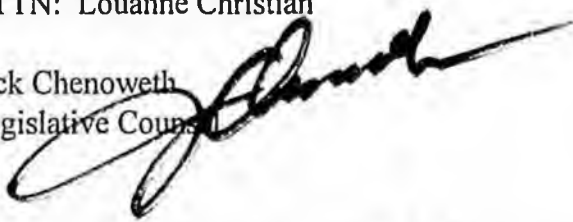
## MEMORANDUM

March 25, 1996

**SUBJECT:** CSHB 325(FIN) (Work Order No. 9-LS1122\U)

**TO:** Representative Mark Hanley, Co-Chair  
House Finance Committee  
ATTN: Louanne Christian

**FROM:** Jack Chenoweth  
Legislative Council



Inserting amendment R.7 threw off the places of insertion of all other material. Here's a road map through the bill addressing how the other provisions were treated.

Amendment R.5 appears on page 3, as paragraph (dd)(3).

Ken Boyd's suggested treatment of the measure of the 500 barrels per day appears on page 3, as paragraph (dd)(4).

His "for purposes of defining field costs" amendment is set out as (dd)(5)(A), part of the paragraph setting out relevant definitions.

Substitution of reference to "industrial commodities" for "finished goods" is made at the place designated, near the conclusion of (dd)(1)(A)(ii) near the middle of page 2.

The conceptual amendment to require monthly testing and reporting of heavy oil having a 19+ API gravity appears at the conclusion of (dd)(1)(D)(i), at the top of page 3.

I sought to include materials at logical places. If my treatment of these materials is at variance with instructions, please advise.

JBC:glc  
96-180.glc

Enclosure

Amendment 2  
Adopted

Page 2, after line 30

insert "(E) for purposes of calculating the first 500 barrels per day of production from a well, production from dual completions and other forms of multiple completions in a well is to be added together and counted as production from a single well."

AMENDMENT

1 Adopted

OFFERED IN THE HOUSE

TO: CSHB 325(O&G)

1 Page 1, line 10:

2 Delete "."

3 Insert ", as follows:"

4 Page 1, lines 11 - 12:

5 Delete all material.

6 Page 1, line 13:

7 Delete "AS 43.55.900. Under"

8 Insert "(1) under"

9 Page 1, line 14:

10 Delete "(1)"

11 Insert "(A)"

12 Page 1, line 14, through page 2, line 1:

13 Delete "value at the wellhead, net of eligible field cost deductions,"

14 Insert "lessee's reported royalty before any field cost deduction,"

*le*  
~~"AS may be adjusted periodically"~~

15 Page 2, line 3:

16 Delete "(A)"

17 Insert "(i)"

18 Page 2, line 5:

19 Delete "(B)"

3/22/96  
Attachment 1

1           Insert "(ii)"

2   Page 2, lines 6 - 7:

3           Delete "(A) of this paragraph"

4           Insert "(i) of this subparagraph"

5   Page 2, line 9:

6           Delete "(A) of this paragraph"

7           Insert "(i) of this subparagraph"

8   Page 2, line 13:

9           Delete "(2)"

10          Insert "(B)"

11          After "actual":

12          Insert "initial"

13   Page 2, line 14, after "2006;":

14           Insert "for purposes of this subparagraph, "actual initial drilling" does not include  
15   plug-backs of existing wells, sidetracks from existing wells, multi-lateral or dual completions  
16   of existing wells, or sidetracks of redrilled wells;"

17   Page 2, line 15:

18           Delete "(3)"

19           Insert "(C)"

20   Page 2, line 16, after "start of":

21           Insert "initial"

22   Page 2, line 17, after "Commission;":

23           Insert "for purposes of this subparagraph, "initial production" means production  
24   following initial drilling;"

1 Page 2, line 18:

2 Delete "(4)"

3 Insert "(D)"

4 Page 2, line 19:

5 Delete "(A)"

6 Insert "(i)"

7 Page 2, line 20:

8 Delete "(1) - (3) of this subsection"

9 Insert "(A) - (C) of this paragraph"

10 Page 2, line 26:

11 Delete "(F)"

12 Insert "(ii)"

13 Page 2, line 30, after "hours":

14 Insert ";

15 (2) by taking an exemption from the payment of royalty under this  
16 subsection, the lessee waives any right that the lessee might otherwise have under its  
17 lease, unit agreement, or other agreement with the state to deduct, against royalty due  
18 the state, any field costs associated with the production of the heavy oil for which the  
19 exemption is taken; and

20 (3) in this subsection, "heavy oil" means oil having a weighted average  
21 equal to or less than 20 degrees API gravity as the term "API gravity" is defined in  
22 AS 43.55.900"

**CS FOR HOUSE BILL NO. 325(O&G)**

**IN THE LEGISLATURE OF THE STATE OF ALASKA**

**NINETEENTH LEGISLATURE - SECOND SESSION**

**BY THE HOUSE SPECIAL COMMITTEE ON OIL AND GAS**

**Offered: 1/24/96**

**Referred: Resources, Finance**

**Sponsor(s): REPRESENTATIVE GREEN**

**A BILL**

**FOR AN ACT ENTITLED**

1 "An Act authorizing exemption from payment of royalty for initial production of  
2 a portion of the heavy oil produced from wells on the Arctic Slope; and  
3 providing for an effective date."

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

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

6 (dd) Notwithstanding any other provision of this section or any provision in  
7 a lease, unit agreement, or other agreement between a lessee and the state that  
8 establishes an obligation to pay royalty on production, royalty is not payable, under the  
9 conditions and to the extent described in this subsection, for the production of heavy  
10 oil that is removed or sold from a lease or leases located north of the Umiat baseline.  
11 For purposes of this subsection, "heavy oil" means oil having a weighted average equal  
12 to or less than 20 degrees API gravity as the term "API gravity" is defined in  
13 AS 43.55.900. Under this subsection, the exemption from payment of royalty applies

14 (1) only to the portion of the value at the wellhead, net of eligible field

*to the Lessee's Reported  
Royalty Value*  
-1- CSHB 325(O&G)

1 cost deductions, as calculated for the month of production, for the first 500 barrels of  
2 daily production of heavy oil from the well, that, for the period beginning on

3 (A) the effective date of this section and until December 31,  
4 1996, does not exceed \$15 per barrel; and

5 (B) the first day of the calendar year during each calendar year  
6 beginning January 1, 1997, does not exceed the amount specified under (A) of  
7 this paragraph as adjusted for inflation or deflation; in making the adjustment, the  
8 department shall, not later than February 15 of each calendar year, calculate and  
9 apply to the amount set out in (A) of this paragraph a change in the dollar  
10 amount to the extent of the change in the producer price index for finished goods  
11 compiled by the United States Department of Labor; the index for January 1996  
12 is the reference base index;

13 (2) only if the actual drilling of the well from which the heavy oil is  
14 produced began on or after July 1, 1996, and before July 1, 2006;

15 (3) only to heavy oil produced during the first 1,825 days of well  
16 operation after the start of production of oil from the well, as reported to the Alaska Oil  
17 and Gas Conservation Commission; and

18 (4) for a well only if the lessee

19 (A) submits with its royalty report for the first month for which  
20 the exemption from royalty payment under (1) - (3) of this subsection is claimed  
21 and with subsequent royalty reports at quarterly intervals for so long as the  
22 exemption continues, oil gravity test results performed during the period for  
23 which the royalty report is filed demonstrating that the oil tested is heavy oil; the  
24 report must be in accordance with the standards for measurement and testing set  
25 out in the regulations of the Alaska Oil and Gas Conservation Commission; and

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

31 \* Sec. 2. This Act takes effect immediately under AS 01.10.070(c).

*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.<sup>1/</sup> 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:

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

Shallow Oil Sands Nomenclature

AGE	TYPE LOG		TERMINOLOGY		
	MILNE POINT UNIT	MILNE POINT UNIT	Informal Milne Point Unit	Informal Kuparuk Unit	Formal North Slope GPT FORMATION
	Gamma Ray	Resistivity			
TERTIARY	[Type Log Graph]		K Sands	UPPER	SAGAVAN-IRKTOK
			L Sands	UGNU	
			M Sands	SANDS	PRINCE CREEK
			N Sands	LOWER	
			O Sands	WEST SAK SANDS	
CRETACEOUS	[Type Log Graph]		A	B	COLVILLE
					SCHRADER BLUFF

Chart 1

<sup>1/</sup> 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.<sup>2/</sup>*

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 it's production poses a challenge to industry and governments worldwide.<sup>3/</sup> For its part, Alaska's oil industry has

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<sup>2/</sup> University of Alaska Anchorage, School of Public Affairs and Institute of Social and Economic Research, *"Heavy Oil Development: The Economic Impact,"* December, 1995.

<sup>3/</sup> 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. <sup>4/</sup>

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. <sup>5/</sup>

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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).

<sup>4/</sup> 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.

<sup>5/</sup> 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.<sup>6/</sup> The suspension would apply only to the first 500 bbls./day of production from each well.

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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.

<sup>6/</sup> 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; <sup>7/</sup> 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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<sup>7/</sup> 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

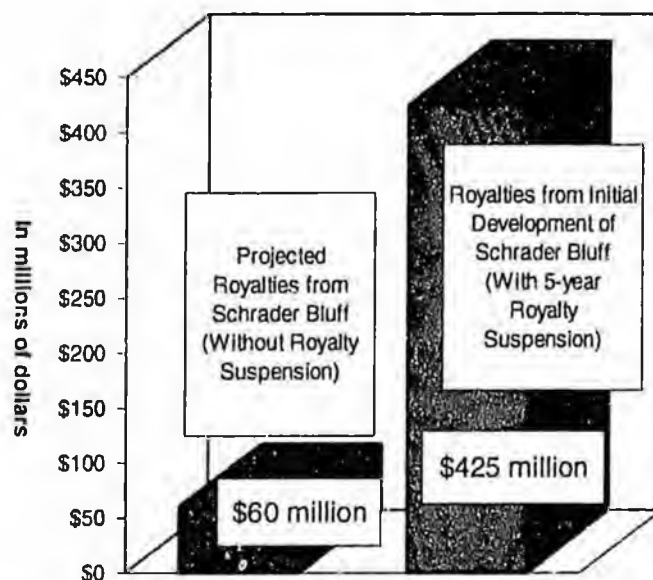


Chart 2. <sup>6/</sup>

<sup>6/</sup> 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

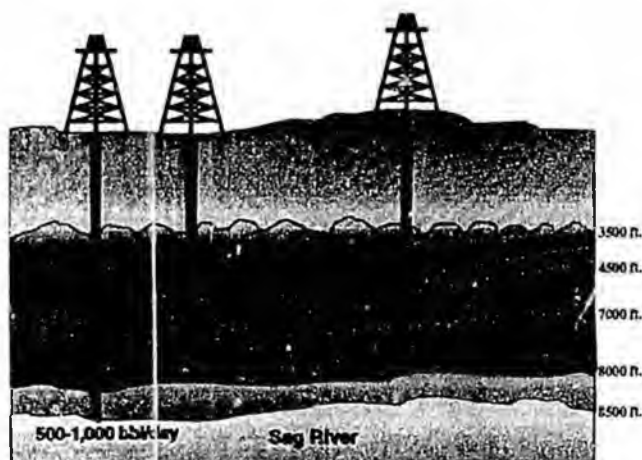
### A. An Overview of the Milne Point Unit.

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

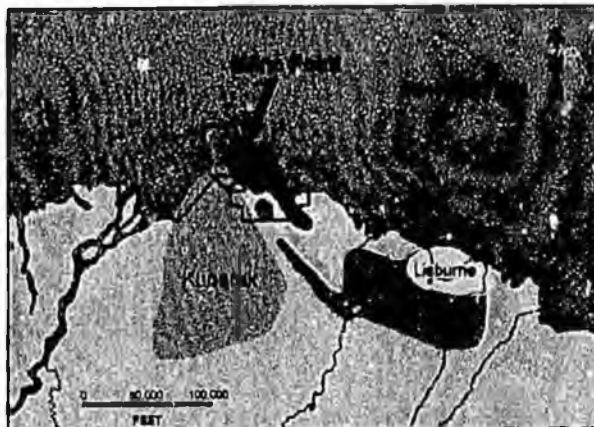
1993, Conoco and Chevron sold their interest in the unit to BP Exploration (Alaska) Inc. ("BP"), and today 91.19% of the unit is owned by BP, and the remaining 8.81% by

### *Production Formations at Milne Point*



*Chart 4*

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



*North Slope Fields and Milne Unit Outline*

*Chart 3*

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.

*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

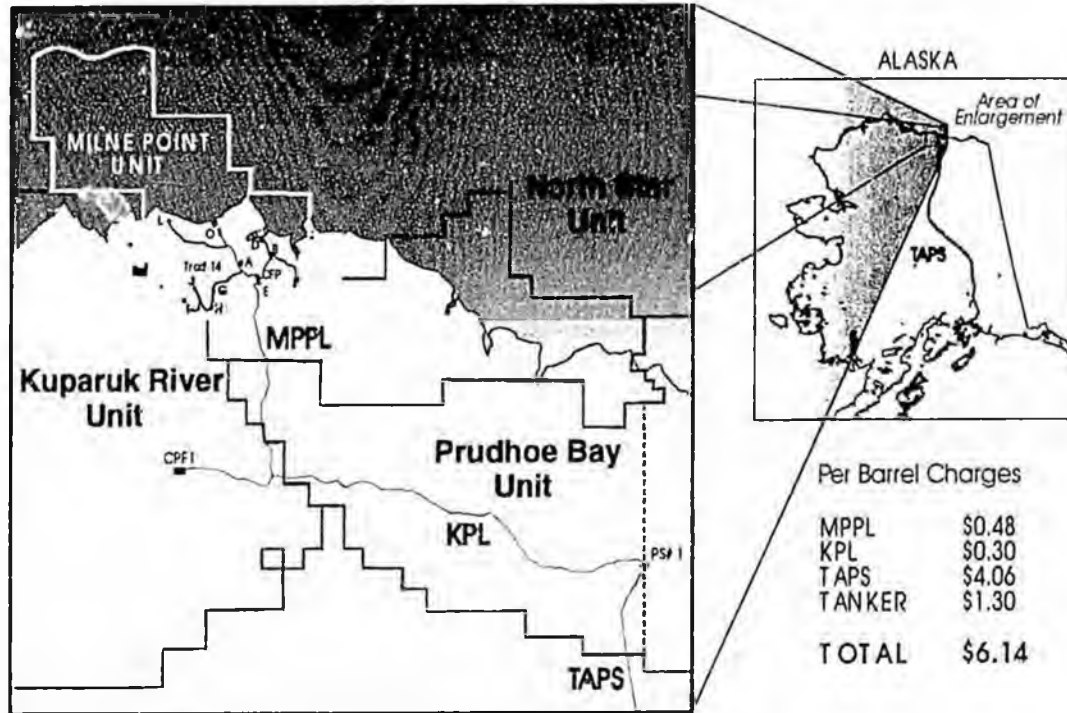
*Schrader Bluff (3,000 bbl./day).* Current production from this formation's heavy oil reserves comes from a pilot project initiated in 1990. The API gravity of Schrader Bluff oil ranges from 14-20 degrees. The companies' efforts to overcome the roadblocks to development of this resource are discussed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

- ∅ *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;
- ∅ *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;
- ∅ *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



A-96  
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*

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

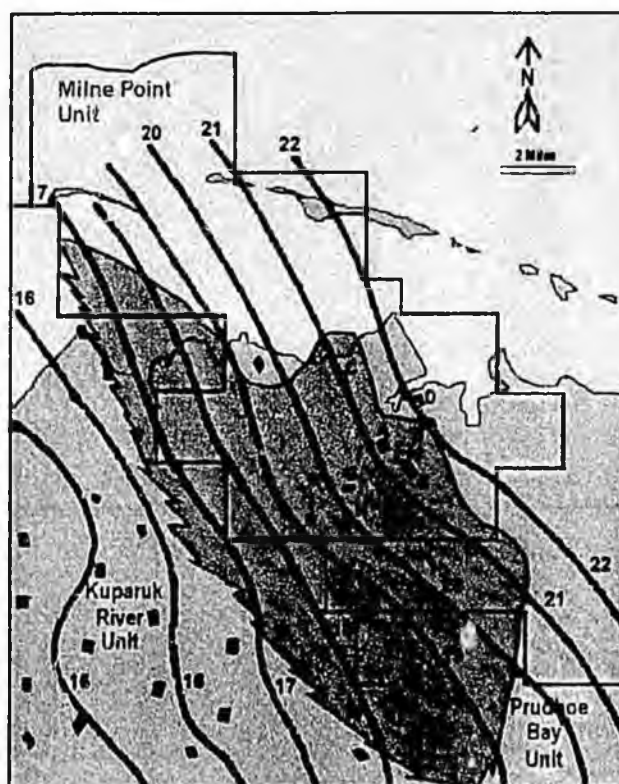
It is within this economic environment that BP and OXY have faced the challenge of developing the unit's heavy oil resources.

### 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.<sup>9/</sup> 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

<sup>9/</sup> 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. §613A(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.<sup>10/</sup> 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.*

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<sup>10/</sup> 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 \$9.30/bbl. still made the exercise uneconomic, and initial flow rates from Tract 14 wells only averaged 275

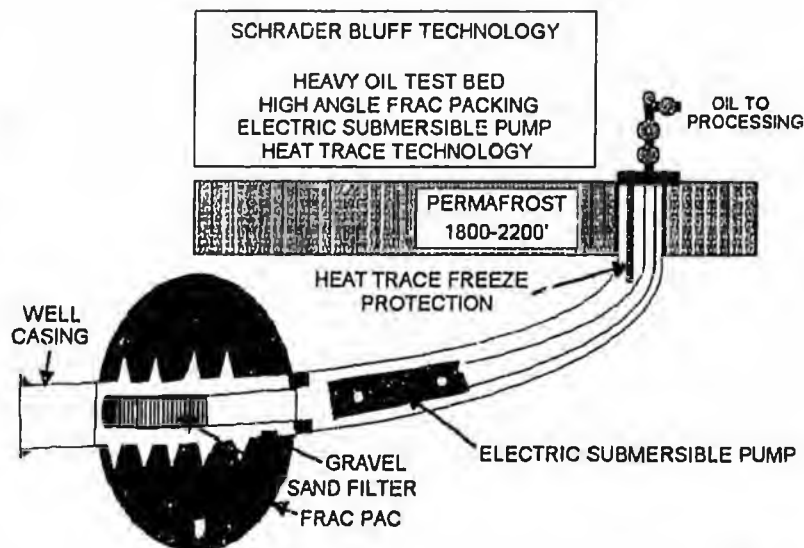


Chart 7

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:

- ∅ *Advances in technology and better geologic information have made initial flow rates of 300-400 bbls./day practical; and*
- ∅ *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.<sup>11/</sup> As Chart 8 illustrates, with development of Schrader Bluff's heavy oil, the unit's profile looks different.<sup>12/</sup>

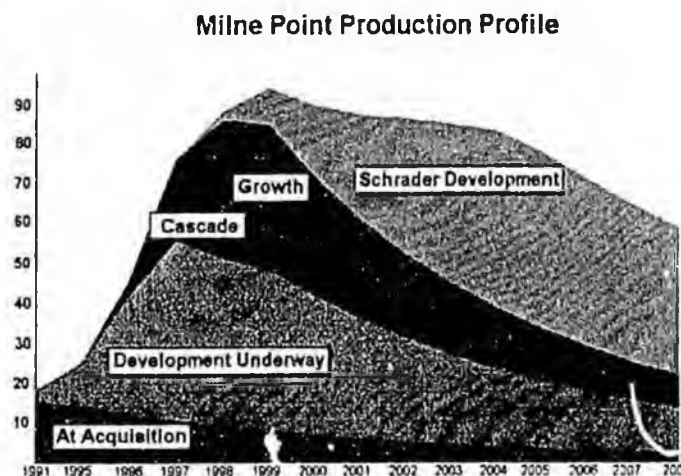


Chart 8

<sup>11/</sup> *Historical and Projected Oil and Gas Consumption*, March, 1995 at 6-7.

<sup>12/</sup> 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 1993; (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.

If 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. <sup>13/</sup> 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. <sup>14/</sup> 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;*

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<sup>13/</sup> The analysis, entitled "Heavy Oil Development: The Economic Impact," is available on request from either UAA or BP.

<sup>14/</sup> 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.

- ∅ *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*
- ∅ *An Alaska resident payroll of \$171 million during the development phase, out of a total Alaska payroll of \$206.5 million.<sup>15/</sup> 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:

- ∅ *58 new long-term direct oil industry jobs in Alaska, of which 46 would be held by Alaska residents;*
- ∅ *An additional 76 new indirect and vendor jobs created in Alaska;*
- ∅ *All tolled, 134 new private sector jobs created in Alaska, of which 122 would be held by Alaska residents; and*
- ∅ *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.*

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<sup>15/</sup> 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.

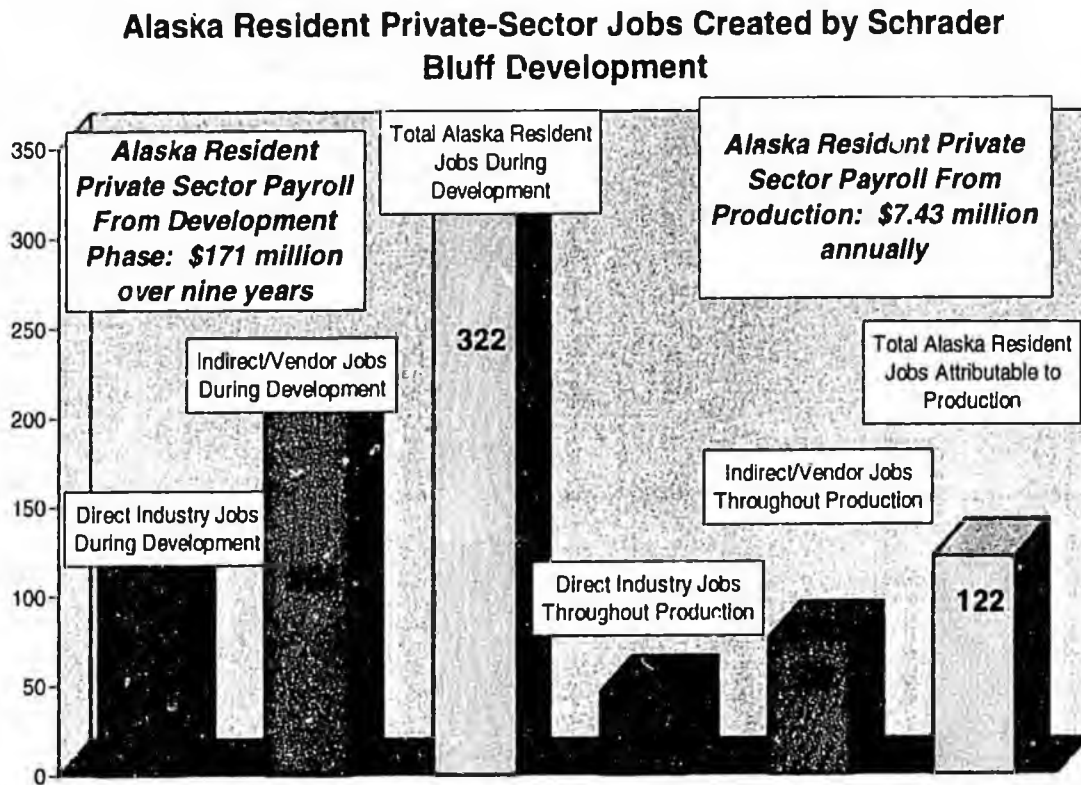


Chart 9

## 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.<sup>16/</sup> 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

<sup>16/</sup> 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. <sup>17/</sup>

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 *Chart 10*

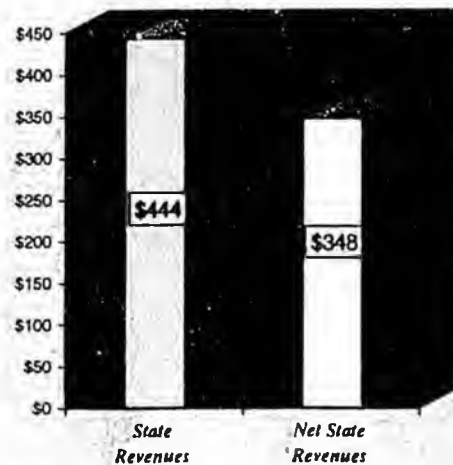
Schrader Bluff heavy oil travelling through it. Declining ANS production in the 21st century will cause upward pressure on per-barrel TAPS tariffs. As more Schrader Bluff oil passes through the TAPS line, the tariff on *all* ANS crude decreases, and the resultant wellhead value on *all* ANS crude increases.

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.

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



<sup>17/</sup> 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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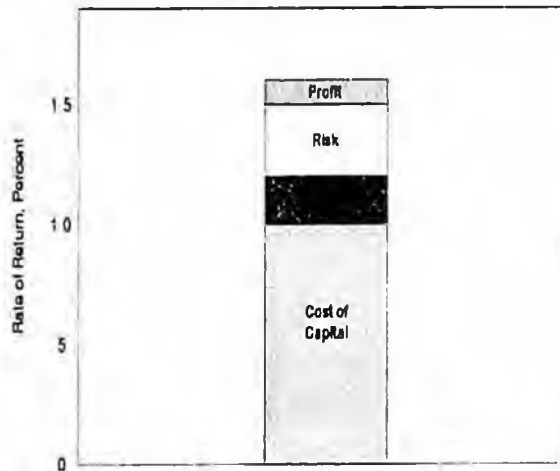
#### IV. The Economics of Schrader Bluff Development.

##### 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."<sup>18/</sup>

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**



Ø *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:<sup>19/</sup>*

Chart 11

Ø *Overhead. Any new investment must bear its requisite share of the corporation's overall overhead costs, such as corporate management;*

<sup>18/</sup> Little Report at 9.

<sup>19/</sup> 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." ;<sup>20/</sup> 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.

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<sup>20/</sup> *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; <sup>21/</sup>*
- 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.*

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<sup>21/</sup> 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:

- ∅ *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

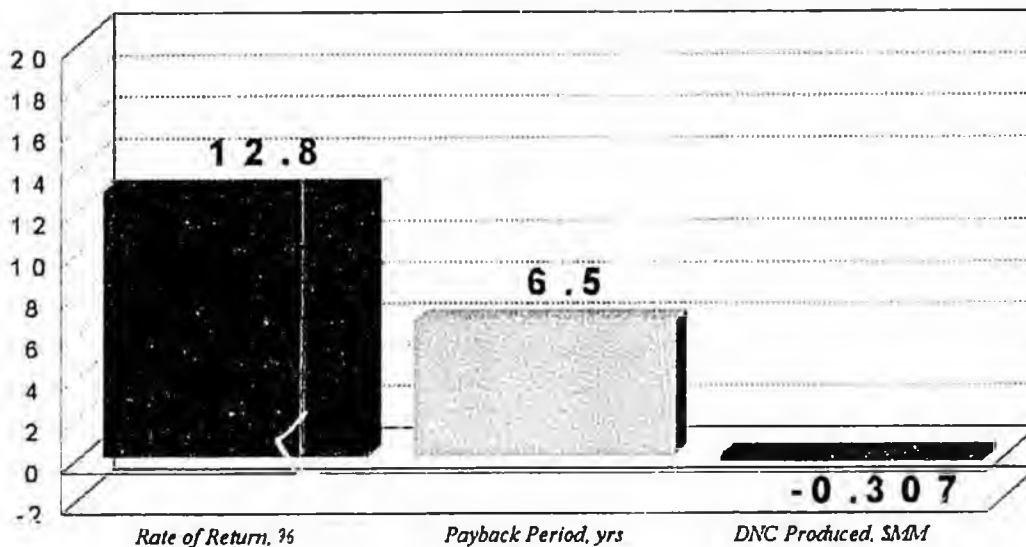


Chart 12

- ∅ *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*
- ∅ *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:

- ∅ *Specificity.* As Section II(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, SLA 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,<sup>22</sup> / and a new field is eligible for relief only if there has been no commercial production from that field.<sup>23</sup> /*

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

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<sup>22</sup>/ AS 38.05.180(j)(4)(A).

<sup>23</sup>/ AS 38.05.180(j)(1)(A)(ii). 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 V(C)(6-7), post.*<sup>24/</sup>

- ∅ *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.<sup>25/</sup> 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*

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<sup>24/</sup> The relationship of HB 207 to the issues raised by this paper is discussed further in Appendix A.

<sup>25/</sup> This, for example, is the purpose behind BLM'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 or field." 60 *Federal Register* at 18081 (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;*

- ∅ Credibility. Simply put, Alaska should look to initiatives that have proven successful in spurring capital investment in marginal fields in other oil producing jurisdictions.*
- ∅ 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.*
- ∅ 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:

- ∅ 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

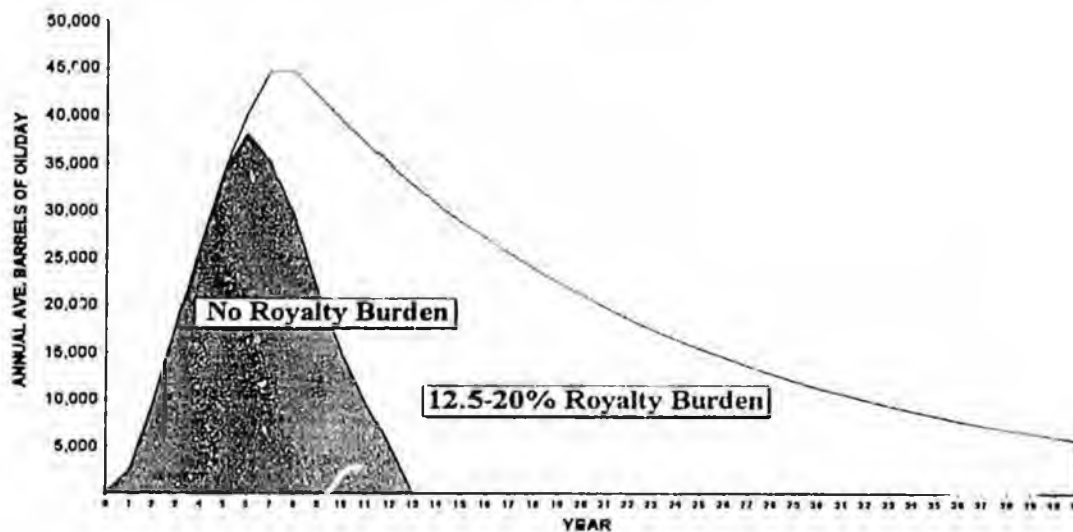


Chart 13

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

- ◊ *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.*

- ◊ *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.*
- ◊ *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: <sup>26/</sup>

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<sup>26/</sup> 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>Jurisdiction</u>	<u>Investment Targeted</u>	<u>Length of Suspension</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:

- ∅ *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;*
- ∅ *\$4.122 billion more in natural gas produced in the state over the period;*
- ∅ *\$240 million in additional sales tax revenues generated over the period;*
- ∅ *104,000 new additional employment years created over the period; and*

∅ \$12 billion in additional economic value generated for the state of Texas over the period. <sup>27/</sup>

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**

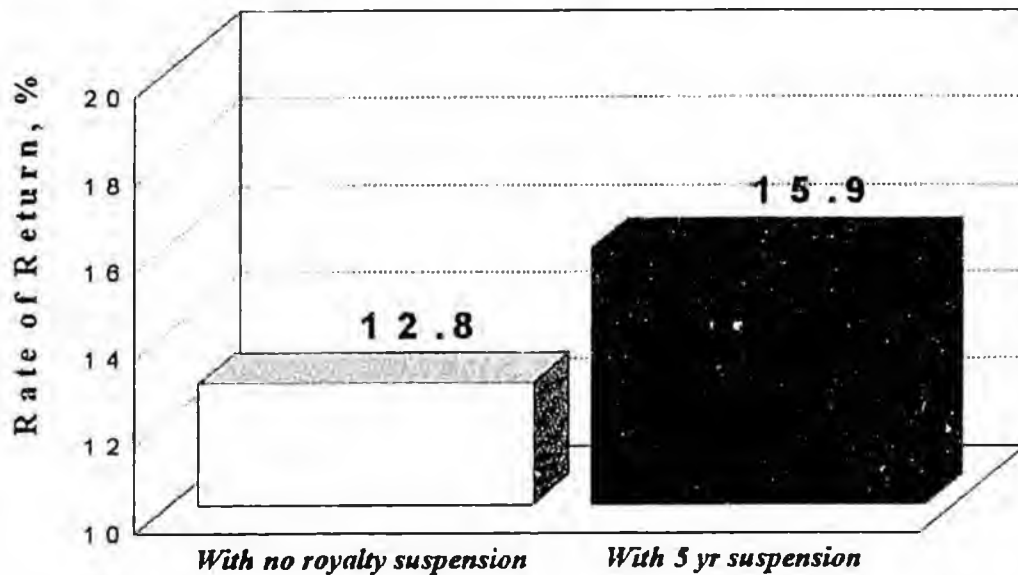


Chart 14

<sup>27/</sup> 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

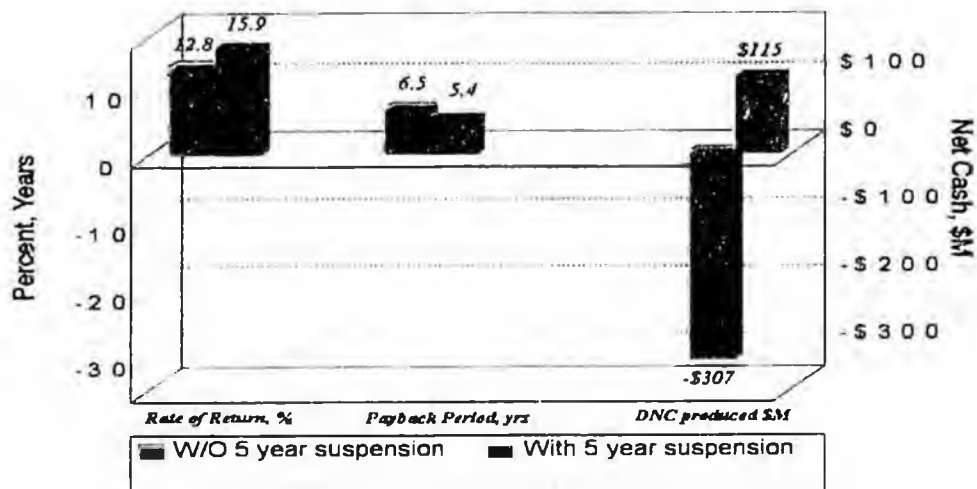


Chart 15

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.

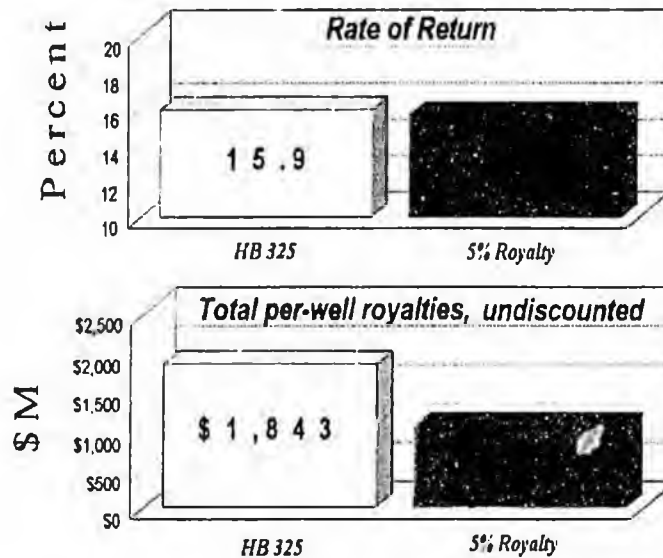
Moreover, and by the very nature of the suspension proposal, the state is better assured a full share of any increased profits caused by either technology or unanticipated oil price increases. With full lease royalties commencing in each well's sixth year of production, the state's risk of losing its 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.

**H B 325 Meets the Necessary and Sufficiency Criteria....**

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



*Char: 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.<sup>1/</sup>*

*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:*

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<sup>1/</sup> *Conoco Inc. v. State of Alaska, Department of Natural Resources, 1JU-91-797Civ.; OXY USA Inc. v. State of Alaska, Department of Natural Resources, 1JU-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 discriminatory 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. <sup>2/</sup>*

*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.*

---

<sup>2/</sup> 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.*

AMENDMENT #7

Adopted

OFFERED IN THE HOUSE

BY REPRESENTATIVE BROWN

TO: CSHB 325(O&G)

Mud

1 Page 1, line 10, after "baseline.":

2           Insert "When an exemption from payment of royalty is obtained on the production of  
3 heavy oil under this subsection, for a period of 20 years after the last day on which a royalty  
4 payment exemption is allowed under this subsection a lessee may not claim or obtain the  
5 benefit of an adjustment of royalty on the production of oil under contract or any other  
6 provision of law authorizing a royalty modification."

HOUSE COMMITTEE REPORT

(11)

Date Referred to Committee: February 7, 1996

FURTHER REFERRALS:

Date of Committee Action: 3/22/96

The FINANCE Committee considered:

HB 325

HOUSE BILL NO. 325

ROYALTY SUSPENSION: N. SLOPE HEAVY OIL

"An Act authorizing suspension of payment of a portion of the royalty due the state for initial production of heavy oil from wells on the Arctic Slope."

recommends it be replaced with the following committee substitute CS HB 325 (Fin)  the same title  a new title

additional referral to \_\_\_\_\_ Committee  
 attached amendment(s)

ADOPTS: \_\_\_\_\_ Letter of Intent

ATTACHES NEW FISCAL NOTE(S): (Dept)

APPROVES PREVIOUS: (Dept/Date)

fiscal note(s) Rev

fiscal note(s) DNR 1/24/96

zero fiscal note(s)

zero fiscal note(s)

SIGNING WITH RECOMMENDATIONS		DP	DNP	NR	AM
<i>Richard J. Foster</i>	Foster	X			
<i>Pat Kelly</i>	Kelly			X	
<i>Mark A. Hanley</i>	Hanley			X	
<i>John Mulder</i>	Mulder	X			
<i>Sean Parnell</i>	Parnell			X	
<i>Eric Kohring</i>	Kohring	X			
<i>Eric Therriault</i>	Therriault			X	
<i>Mike Navarre</i>	Navarre				X
<i>Jay Brown</i>	Brown		X		

CHAIR'S SIGNATURE *Mark Hanley* *Richard J. Foster*

Revision Date: \_\_\_\_\_ Dept. Affected: Revenue  
 Title: Royalty Suspension: N. Slope Heavy Oil BRU: Revenue Operations  
 Component: Oil and Gas Audit  
 Sponsor: Representative Green  
 Requestor: H) Finance COMPONENT SERIAL NO. 115

Expenditures/Revenues:		Thousands of Dollars					
OPERATING EXPENDITURES	FY 97	FY 98	FY 99	FY 00	FY 01	FY 02	
PERSONAL SERVICES							
TRAVEL							
CONTRACTUAL							
SUPPLIES							
EQUIPMENT							
LAND & STRUCTURES							
GRANTS, CLAIMS							
MISCELLANEOUS							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	
CAPITAL EXPENDITURES							
CHANGE IN REVENUES ( )	0.0	0 - (300.0)	0 - (2,000)	0 - (7,000)	0 - (13,000)	0 - (19,000)	

FUND SOURCE		Thousands of Dollars					
1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other							
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	

Estimate of any current year (FY96) cost \$ \_\_\_\_\_

POSITIONS:						
FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

(See Attached Analysis)

Prepared by: Chuck Logsdon Phone: (907) 276-1363  
 Division: Oil and Gas Audit Date: February 13, 1996  
 Approved by Commissioner: Wilson F. Condon Date: February 13, 1996  
 Agency: Department of Revenue

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Analysis of Bill/Program Effects

This revised fiscal note is prepared to illustrate more specifically the potential revenue impacts of the bill. To a large extent the revenue outcome of any legislation which is designed to promote a particular economic activity is uncertain. This revised fiscal note presents two alternative outcomes for heavy oil royalty holiday as applied to the Schrader Bluffs using the Department of Revenue Fall 1995 forecast production, wellhead price and well assumptions. This analysis does not include the West Sak heavyoil production from the Kuparuk unit which in the Fall Forecast is assumed to begin in a small way (.012 million bbl/day) in FY 2003.

Scenario #1  
 Holiday Ensures Large Scale Heavy Oil  
 Development Which would Otherwise  
 Not Occur

Scenario #2  
 Development Would Have Occurred  
 Without Holiday

	Incremental Royalty Impact (Millions \$)	Incremental Royalty Impact (Millions \$)
1997	0	0
1998	0	-0.3
1999	0	-2
2000	0	-7
2001	0	-13
2002	0	-19
2003	1	-22
2004	2	-25
2005	7	-21
2006	12	-15
2007	19	-10
2008	19	-7
2009	23	-3
2010	25	-1

Clearly if the holiday is needed to attract the investment, the payoff to the State is long term since no significant added royalty income will flow into the treasury until well into the next decade. At the same time Scenario #2 could be characterized a potential revenue loss scenario and effectively puts a price tag on the likely subsidy to Schrader heavy oil production using the Department of Revenue production assumptions.

Note neither of these scenarios is based on the maximum potential oil production scenarios presented in industry documents during testimony on this legislation.

Adopted

9-LS1122R.5  
Chenoweth  
2/9/96

AMENDMENT

7

OFFERED IN THE HOUSE

BY REPRESENTATIVE BROWN

TO: CSHB 325(O&G)

1 Page 1, line 10, after "baseline.":

2       Insert "When an exemption from payment of royalty is obtained on the production of  
3 heavy oil under this subsection, for a period of 20 years after the last day on which a royalty  
4 payment exemption is allowed under this subsection a lessee may not claim or obtain the  
5 benefit of an adjustment of royalty on the production of oil under contract or any other  
6 provision of law authorizing a royalty modification."

The Honorable Mark Hanley  
Alaska State Representative  
March 22, 1996  
Page 2

I further suggest two "housekeeping" amendments:

Page 2, line 10

delete "finished goods"  
insert "industrial commodities"

Adopted  
Amendment 4

Page 2, line 22

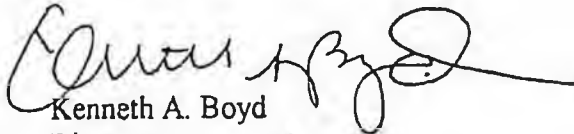
insert after the word "performed":  
"at least once monthly"

wells above 19.0% API  
GRAVITY

Conceptual Amendment  
# 5 amended  
Adopted

I continue to have concerns with the overall approach taken in the legislation and the proposed 500 b/d, \$15/b and 10 year open window trigger points. I still believe that HB-207 is the proper vehicle to determine both the need for, and level of, royalty relief. Heavy oil has an important role to play in the future on the north slope. Hopefully we can continue to discuss our differences and reach a common understanding.

Sincerely,



Kenneth A. Boyd  
Director

032296nh.kb

Jack  
call me  
Louanne  
6814

CS FOR HOUSE BILL NO. 325(O&G)

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - SECOND SESSION

BY THE HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Offered: 1/24/96

Referred: Resources, Finance

Sponsor(s): REPRESENTATIVE GREEN

A BILL

FOR AN ACT ENTITLED

1 "An Act authorizing exemption from payment of royalty for initial production of  
2 a portion of the heavy oil produced from wells on the Arctic Slope; and  
3 providing for an effective date."

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

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

6 (dd) Notwithstanding any other provision of this section or any provision in  
7 a lease, unit agreement, or other agreement between a lessee and the state that  
8 establishes an obligation to pay royalty on production, royalty is not payable, under the  
9 conditions and to the extent described in this subsection, for the production of heavy  
10 oil that is removed or sold from a lease or leases located north of the Umiat baseline.] As follows.

11 [For purposes of this subsection, "heavy oil" means oil having a weighted average equal  
12 to or less than 20 degrees API gravity as the term "API gravity" is defined in]

13 [AS 43.55.900. Under] this subsection, the exemption from payment of royalty applies

14 (A) [(1)] only to the portion of the value at the wellhead, net of eligible field

lessee's reported royalty before any field cost deduction

1 cost deductions,] as calculated for the month of production, for the first 500 barrels of  
2 daily production of heavy oil from the well, that, for the period beginning on

3 (i) (A) the effective date of this section and until December 31,  
4 1996, does not exceed \$15 per barrel; and

5 (ii) (B) the first day of the calendar year during each calendar year  
6 beginning January 1, 1997, does not exceed the amount specified under (A) of  
7 this paragraph] as adjusted for inflation or deflation; in making the adjustment, the  
8 department shall, not later than February 15 of each calendar year, calculate and  
9 apply to the amount set out in <sup>(i) of this subparagraph</sup> (A) of this paragraph] a change in the dollar  
10 amount to the extent of the change in the producer price index for finished goods  
11 compiled by the United States Department of Labor; the index for January 1996  
12 is the reference base index;

13 E (2) only if the actual <sup>(1996-2006)</sup> drilling of the well from which the heavy oil is  
14 produced began on or after July 1, 1996, and before July 1, 2006; <sup>for the purposes of this</sup>

15 (C) (3) only to heavy oil produced during the first 1,825 days of well  
16 operation after the start of production of oil from the well, as reported to the Alaska Oil  
17 and Gas Conservation Commission; and <sup>see 1996-1997 Alaska Oil and Gas Conservation Commission</sup>

18 (D) (4) for a well only if the lessee

19 (i) (A) submits with its royalty report for the first month for which  
20 the exemption from royalty payment under (1) - (3) of this subsection is claimed <sup>A-C of</sup>  
21 and with subsequent royalty reports at quarterly intervals for so long as the <sup>the 1996-1997</sup>

22 exemption continues, oil gravity test results performed during the period for  
23 <sup>19. monthly</sup> which the royalty report is filed demonstrating that the oil tested is heavy oil; the  
24 <sup>19. quarterly</sup> report must be in accordance with the standards for measurement and testing set  
25 out in the regulations of the Alaska Oil and Gas Conservation Commission; and

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

31 \* Sec. 2. This Act takes effect immediately under AS 01.10.070(c).

# Alaska State Legislature

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FINANCE SUBCOMMITTEES  
DEPT. OF NATURAL RESOURCES  
DEPT. OF COMMERCE & ECONOMIC DEVELOPMENT  
DEPT. OF ENVIRONMENTAL CONSERVATION

Representative Joe Green  
District 10

## 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 500 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.

Mr. John Morgan  
BP Exploration (Alaska) Inc.  
February 9, 1996

Mr. Edward J. Behm  
OXY USA Inc.

*Confidential*

Per-well economics. The "Critical Assumptions" sheet provides a summary guide to the kind and detail of information required by the Division. Supporting data necessary includes:

1. Production and Revenues: the historical data for each Schrader Bluff well, including initial production rates, decline rates and per-well reserves, plus all back-up data supporting the chart presented in BP's Finance Committee presentation on February 8, 1996 ("BP's Presentation") entitled "Schrader Bluff Typical Well Production Rate vs Time (years)."
2. Drilling and equipment costs: historical data for each Schrader Bluff well, plus an analysis of the cost reduction trends including any documents supporting the statement made in BP's Presentation that the 1995 Schrader Bluff development program has demonstrated that drilling costs have been reduced, that completion costs have remained constant, and that ESP life has been improved. Provide the results of the well performance and technical study referred to in BP's Presentation as soon as it is available.
3. Supporting data for the dry hole cost assumption of 86.80% of producing well costs and for the 90% success rate assumption.
4. Back-up data and analysis for the \$0.72/bbl associated facility cost, including an explanation of the calculation used. This component should be also thoroughly documented in the Schrader Bluff development economics.
5. Complete detail and analysis for the \$2.20/bbl operating expense estimate and a detailed explanation of the \$0.50/bbl for fixed per-well operating expense. The operating expenses should also be thoroughly documented in the Schrader Bluff pool development economics. Forecasts of both this component and item 4 above must be supported by historical (actual) data.
6. Complete detail and analysis for OXY's calculation of 0.6% severance tax and 8.0% property tax percentages calculated on revenue, including an explanation of why revenue was used instead of the oil value and property assessment. If BP has different values, please provide those values plus the supporting detail.

Schrader Bluff pool development. It is the Division's understanding that the decision to develop the Schrader Bluff is not made on a well-by-well basis. For example, Mr. Policky testified that development of the Schrader Bluff pool would require upgrading of the central production facility serving all horizons in the unit. BP and OXY should each provide the Division with the complete analysis of the whole project, including any documentation describing the "full development scenario" of 350-400 wells presented in OXY's Critical Assumption sheet versus any documentation describing the 230 well

10 1995




**BP EXPLORATION**

**James A. Palmer**  
Director  
External Affairs  
Alaska

BP Exploration (Alaska) Inc  
900 East Benson Boulevard  
P O Box 196612  
Anchorage, Alaska 99519-6612  
(907) 564-5435

November 10, 1995

Representative Joseph Green  
Alaska State Legislature  
716 W. Fourth Avenue, Suite 350  
Anchorage, Alaska 99501-2133

Dear Representative ~~Green~~ 

Earlier this year, BP Exploration (Alaska) commissioned a study on the economic impacts of marginal oil field development in Alaska. Conducted by the Institute of Social and Economic Research, the results of the study were presented to the State of Alaska Oil and Gas Policy on June 5, 1995.

Although specific marginal fields would have differing degrees of economic and public sector impacts, the general conclusion about the significance of developing marginal oil fields is important to note.

"Marginal oil field development in Alaska can generate jobs and income for Alaska workers, sales for Alaska businesses, and an increase in the state tax base more than sufficient to offset any additional costs to government from resource management and public service requirements from population increase."

Additionally, when compared to the state's natural resource revenues and management expenditures of fishing, lands, wildlife, mining and timber, the marginal oil field is the only case where resource management costs are covered by the revenues generated, and the substantial revenues are available to contribute to the general costs of the government (see Figure 5B in attached summary).

As you know, the oil industry faces a variety of competitive challenges it must overcome in order to attract the funds it needs to survive and grow in Alaska. Together with the state, we've begun to take our first tangible steps toward overcoming our competitive disadvantages by working together. This includes efforts such as last year's legislation that encourages development of new, economically marginal oil fields.

This study is another step in the cooperative process. I thought you would appreciate receiving a copy of the executive summary for your initial examination. If you would like a copy of the entire report, please feel free to give me a call at 564-5435.

Sincerely,

James A. Palmer  
Director, External Affairs  
Alaska

encl:

## MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

### EXECUTIVE SUMMARY

Marginal oil field development in Alaska can generate jobs and income for Alaska workers, sales for Alaska businesses, and an increase in the state tax base more than sufficient to offset any additional costs to government from resource management and public service requirements from population increase.

This conclusion is based on an analysis using existing information about the economy and public sector combined with a description of a hypothetical marginal oil field. In reality, each marginal field would have different characteristics, and the actual economic and public sector effects would differ from the description in this study. However, given the economics of field development, this study demonstrates that the general conclusions are consistent with a broad range of assumptions about both field characteristics and the economy.

The purpose of this study is to provide a framework for analysis of the economic effects of new, small marginal oil fields which may be typical of new petroleum industry activity in Alaska. The analysis is generic and hopefully will lead to more detailed and specific studies where appropriate. Some of the information used to develop the parameters for the analysis come from the ongoing study of the Badami oil field on the North Slope. Since that project is only in the earliest stages of its evolution, it would be inappropriate to interpret this analysis as a study of the Badami prospect.

The study examines a hypothetical marginal oil field on the North Slope with anticipated recoverable reserves of 100 million barrels of oil. We assume a total development budget of \$320 million, most of which would be spent in a two-year period during which the initial wells would be drilled, the pipeline constructed, the modules fabricated and put into place, and the operating facility built. Production would subsequently continue over a 20-year period at a cost of \$320 million. In the early production years, the drilling of wells would continue and after year 5, the drilling activity would switch to workovers of the existing wells. The purpose of these development and production cost figures is to calculate economic effects, and they should not be interpreted as reflecting the actual costs associated with any particular field.

Although some expenditures, in particular module fabrication and equipment for the modules and pipeline, would be purchased outside the state, much of the work would be carried out onsite during both field development and production. These tasks include site preparation, pipeline and module installation, and well drilling; and all have a large labor component. During production the operation of the field and drilling would continue around the clock so the number of workers employed would be 4

times the number of jobs to be done onsite. The development and production jobs would require highly trained and skilled workers so wages would be high and some specialized jobs would, of necessity, be filled by workers from Outside. Based on current experience, the share of jobs going to residents would be high, but some workers would choose to live outside the state.

Other costs associated with field development and production would generate sales, employment, and payrolls for Alaska vendors providing supplies, equipment, and services to the owner company, the oil service companies doing the contract drilling and other work, the construction contractors, etc. A large portion of the economic effect of marginal field development would come from the recirculation within the economy of the high payrolls paid the North Slope workers. These payrolls would generate sales, jobs, and tax base in the communities where the Slope workers live.

Figure 1 shows the size and composition of Alaska employment and payroll which the development and production of the field would generate after subtracting onsite jobs likely to be filled by nonresidents. Field development would be spread over several years, so the number of annual average jobs produced in the peak year would be about 500 with a payroll of \$25 million. As the figure shows, the majority of those jobs would be offsite in vendor businesses, in the communities where the workers reside, and in the public sector. During production the number of jobs would fall to under 250 for an average year, and the pattern again is that most of the jobs would be offsite. However, in both the development and production phases, the payrolls are concentrated onsite.

The actual economic impact in a real situation would depend on the development and production plan as well as the resident share of employment and purchase of other inputs. But once the field size has been estimated, the budget and with it the economic effect would be constrained within a narrowly defined range. Basically the budget must be economically feasible, and the economic effect would flow from that budget. While the economic effects are clearly defined once the development strategy has been identified, the revenues that the field would generate are much less so since they are sensitive to actual, rather than anticipated, production, wellhead price, and the tax and royalty rates in place.

The range of variation of state revenues from production, primarily royalties but also the state share of the property tax and the corporate income tax, in response to variation in these parameters is shown in Figure 2. For example, if over its life the field were to produce 150 million barrels, the wellhead averages \$8.31 (1995 \$) and the royalty rate is 6%, production revenues would be \$84 million. For the range from low to high price, production, and royalty, the range of production revenues is \$29 to \$328 million.

Two other sources of revenue, from the "full pipeline effect" and the payrolls generated by the new jobs, are less volatile and significant. Adding production from a marginal field to the existing throughput of the Alyeska pipeline marginally reduces

the tariff on existing throughput and increases its wellhead value. This "full pipeline effect" would increase severance tax and royalty revenues from production from all North Slope fields. The payroll generated by the marginal field activity represents a tax base which could be tapped to pay some of the state government costs imposed by the new workers and their families. Although the state currently has no vehicle to allow these workers to pay for some of the public services they receive, the tax capacity represented by their payroll should be included as a potential revenue source.

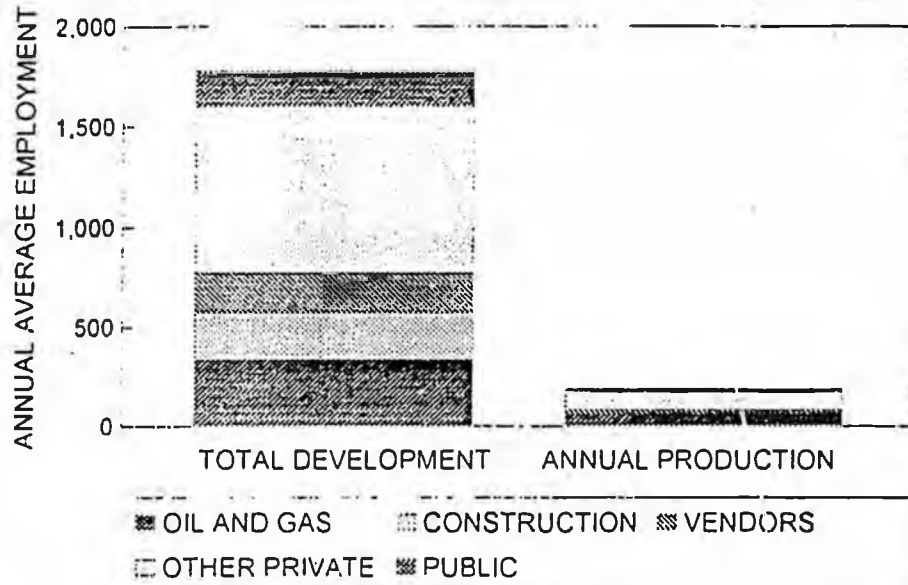
The costs to state government from marginal field development consist of management costs such as environmental monitoring, tax auditing, etc., and more importantly the costs of providing services for the families of the new workers both onsite and in Alaska's urban centers. These costs can be divided into those which support oil industry families, vendor families, and other private and public workers in the urban centers. The public management costs are about \$7 million, and the population-related costs are about \$4.4 million, totaling about \$51 million.

These public sector costs are contrasted with the range of revenues which the field could produce over its life in Figure 3. Subtracting the costs from the revenues yields a range for the state revenue "dividend" (Figure 4), which is the tax base generated by the marginal field over and above the amount necessary to pay for the costs of state government imposed by the field. The "dividend" ranges from \$1 to \$300 million depending upon production, price, and royalty rate.

Figure 5A shows the range of production revenues introduced as Figure 2, converted to an annual equivalent. It contrasts the potential range of revenues for the marginal field with the total annual revenues to the state generated by other natural resources based on a recent analysis of the sources of state revenues prepared by Legislative Research in 1993. The range for the marginal oil field is clearly consistent with the total revenues to the state from most other natural resources.

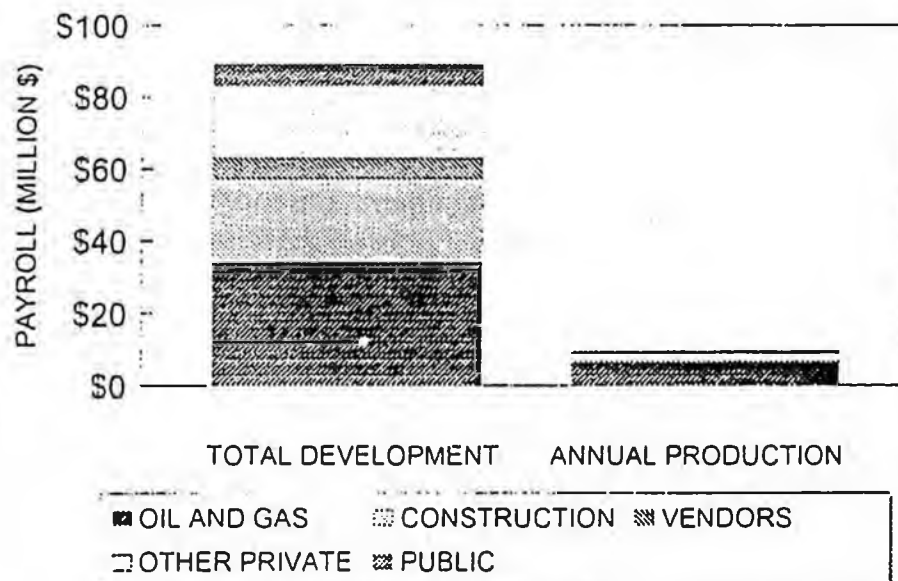
Finally, Figure 5B compares the state's natural resource revenues from various resources with the state's resource management expenditures for those same natural resources. The marginal oil field is the only case where resource management costs are covered by the revenues generated, and the substantial revenues are available to contribute to the general costs of government.

FIGURE 1A. MARGINAL FIELD ECONOMIC EFFECT  
RESIDENT EMPLOYMENT



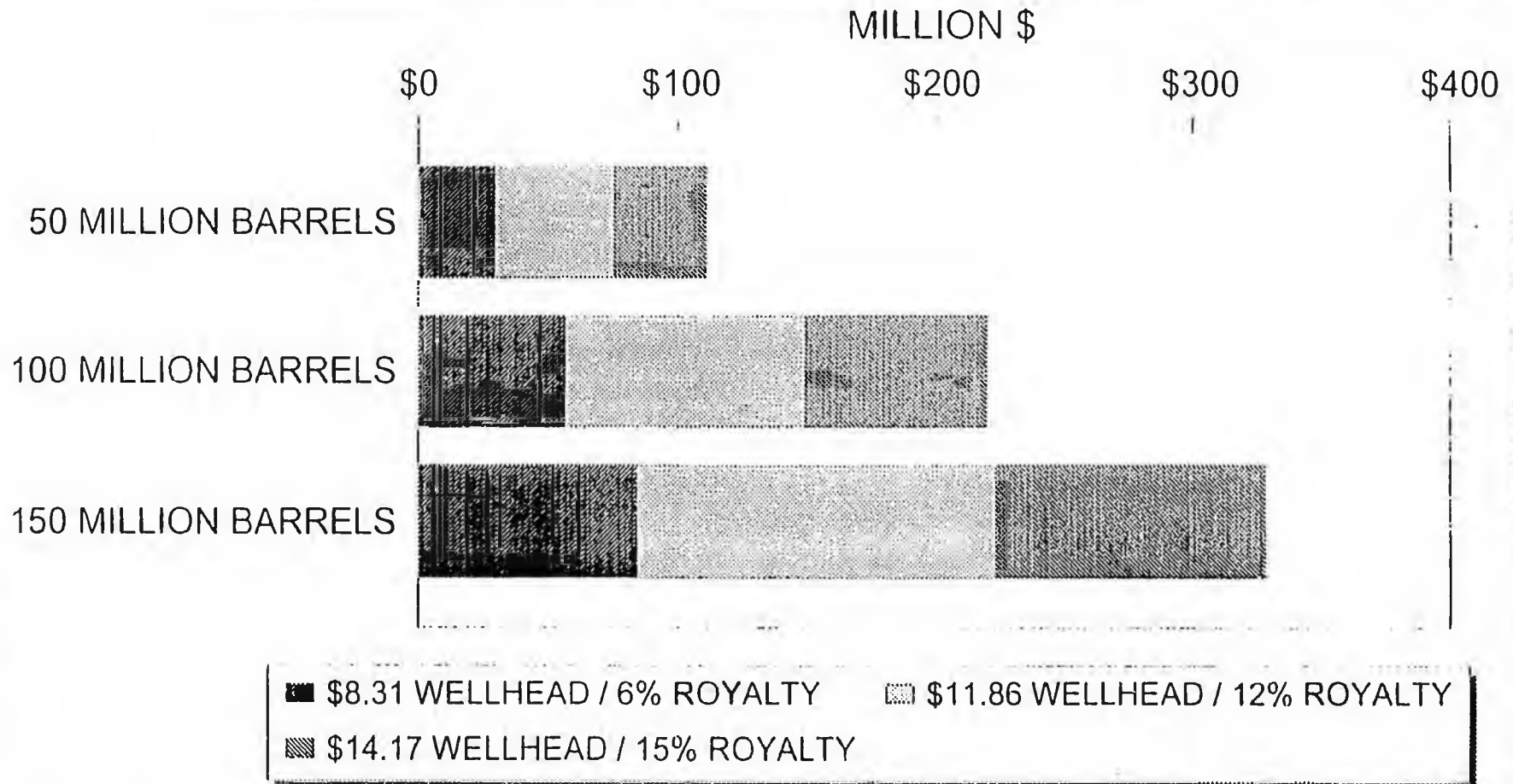
DEVELOPMENT EMPLOYMENT SPREAD OVER SEVERAL YEARS

FIGURE 1B. MARGINAL FIELD ECONOMIC EFFECT:  
RESIDENT PAYROLL



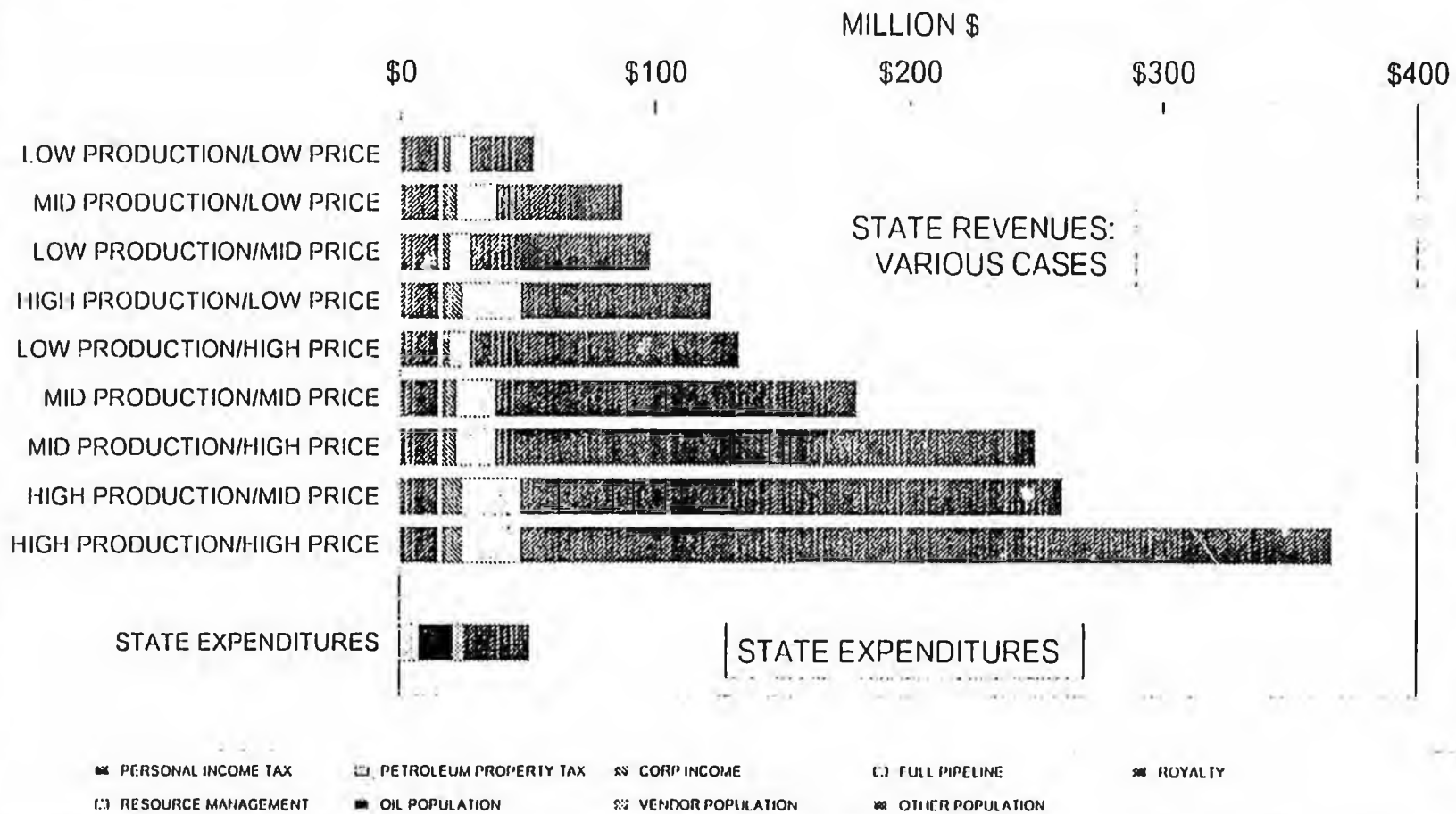
DEVELOPMENT EMPLOYMENT SPREAD OVER SEVERAL YEARS

**FIGURE 2. MARGINAL FIELD PRODUCTION REVENUES**  
 SENSITIVITY TO PRODUCTION, WELLHEAD PRICE, AND ROYALTY RATE



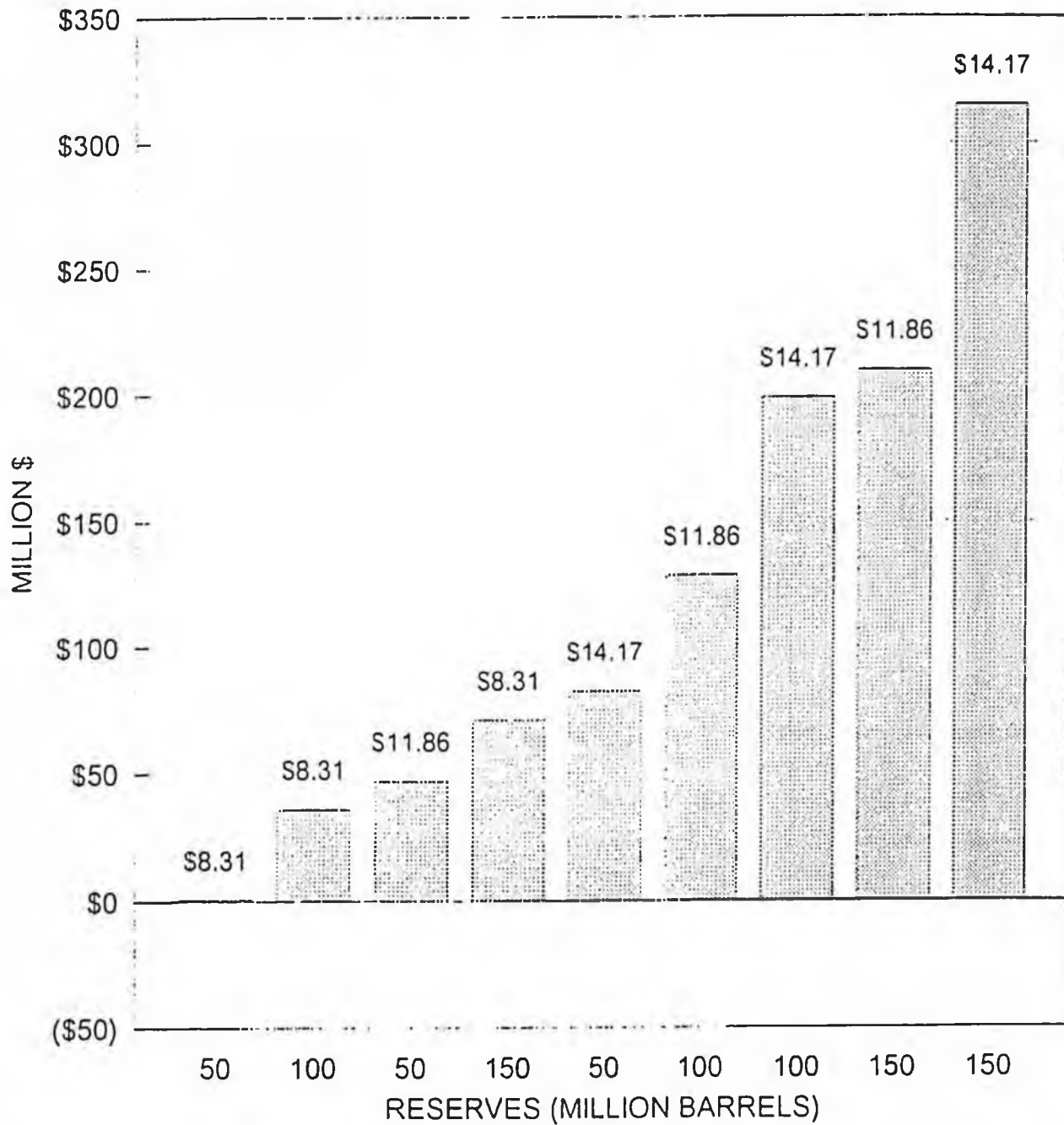
REVENUES OVER THE LIFE OF THE FIELD

FIGURE 3. STATE REVENUES AND EXPENDITURES:  
LIFE OF THE FIELD



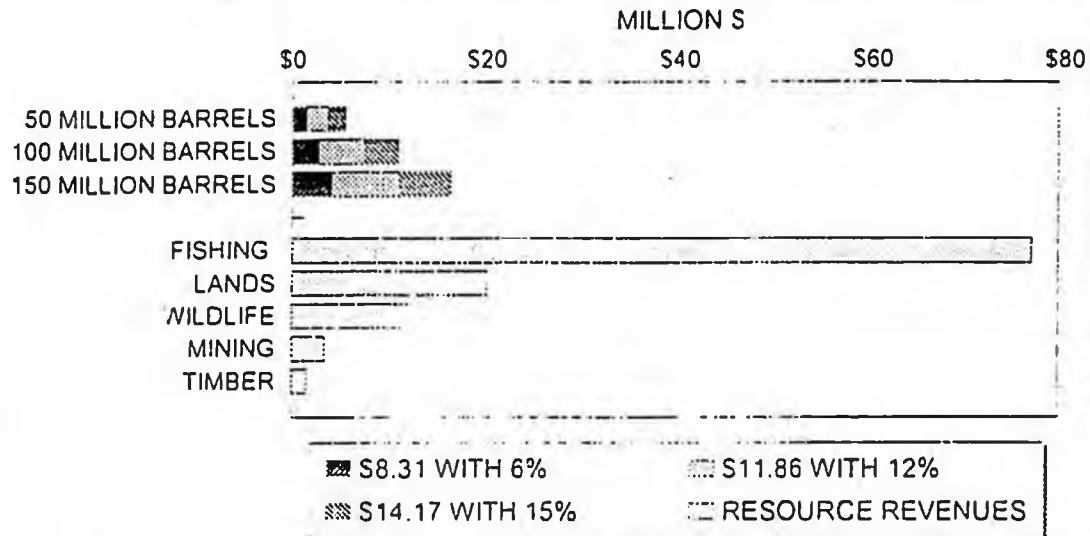
# FIGURE 4. STATE REVENUE "DIVIDEND"

VARIATION IN RESERVES, PRICE, AND ROYALTY RATE



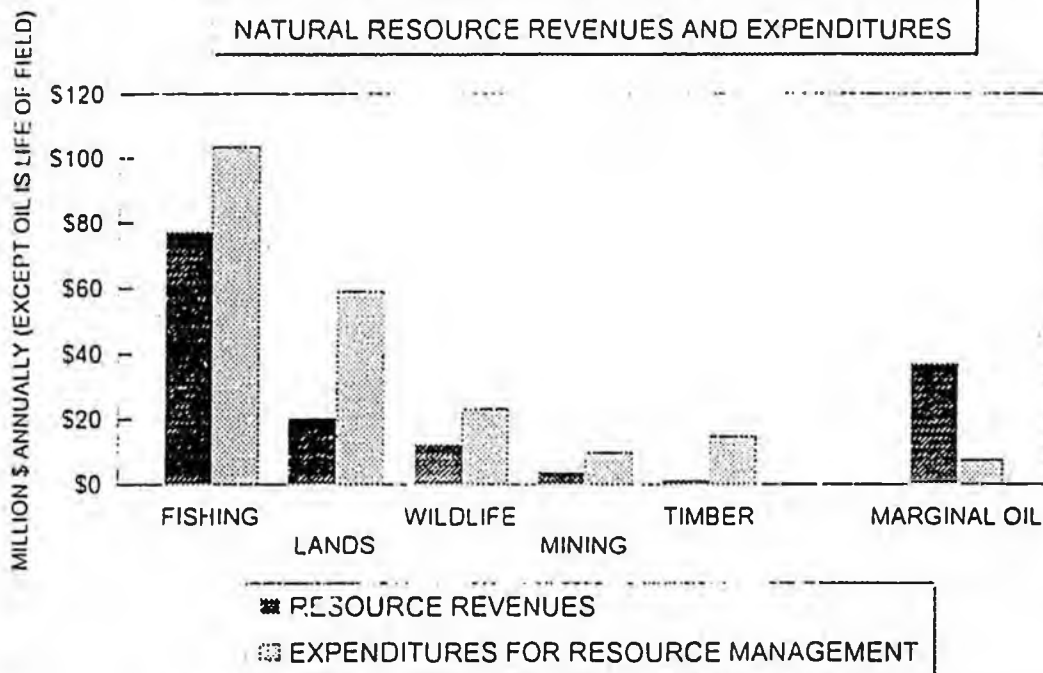
REVENUES IN EXCESS OF AMOUNT NEEDED  
TO PROVIDE NEW PUBLIC SERVICES

**FIGURE 5A. ANNUAL MARGINAL FIELD PRODUCTION REVENUES  
COMPARISON TO TOTAL REVENUES FROM OTHER RESOURCES**



SOURCE FOR OTHER RESOURCES: LEGISLATIVE RESEARCH 1993

**FIGURE 5B. STATE OF ALASKA  
NATURAL RESOURCE REVENUES AND EXPENDITURES**



SOURCE: LEGISLATIVE RESEARCH, 1993.  
EXCEPT MARGINAL OIL IS LOWEST REVENUE CASE FROM TEXT NET OF INCOME AND SALES TAX RE



## CALIFORNIA INDEPENDENT PETROLEUM ASSOCIATION

Main Office: 1112 "I" Street, Suite 350, Sacramento, CA 95814 • 916-447-1177 • Fax 916-447-1144  
Environmental Affairs Office: 5201 Truxtun Avenue, #119, Bakersfield, CA 93309 • 805-633-3119 • Fax 805-633-3191

June 21, 1995

JUL 05 1995

Representative Joe Green  
Alaska State Legislature  
Alaska State Capitol  
Juneau, Alaska 99801

**RE: CIPA Support for HB 325, the "Heavy Oil Royalty Suspension" Bill**

Dear Representative Green:

The California Independent Petroleum Association (CIPA) wishes to express its strong support for HB 325, provided that Congress lifts the ban on the export of Alaskan North Slope crude oil which appears likely to happen soon. CIPA represents over 550 production, exploration and service companies operating in California.

This measure proposes a simple yet effective incentive for independent producers, including those in California, to invest in heavy oil projects in Alaska. As you know, approximately two-thirds of California's oil production is heavy oil and this state's producers know only too well the difficult investment climate for heavy oil and the large role incentives can play in stimulating such activity.

Simplifying the process of obtaining incentives is critical for the independent producer because of limited manpower resources. And in order to be an effective inducement to increase activity, the incentive must significantly affect an independent's economics. HB 325 appears to accomplish both of these goals.

Please do not hesitate to contact me at (916) 447-1185 if I may be of assistance in your deliberations on this proposal.

Sincerely,

A handwritten signature in black ink, appearing to read "Dan K", is written over a horizontal line.

Daniel P. Kramer  
Executive Director

## DENALI

Doyon buys Kantishna roadhouse

BUSINESS • D-1



## TOP 10 UPSETS

No. 4 Colorado 24, No. 24 Kansas 40  
No. 7 Michigan 13, No. 25 Northwestern 19  
No. 8 Texas A&M 7, Texas Tech 14  
No. 9 Virginia 17, North Carolina 22

SPORTS • C-1

## LATHROP

Chugiak wipes c Malemites 18-

SPORTS • C-1



FAIRBANKS

# Daily News-Mine

The Voice of Interior Alaska

VOL. XCIII, No. 272

FAIRBANKS, ALASKA, SUNDAY, OCTOBER 8, 1995

\$1.5

## West Sak's oil powerful magnet

### Giant field draws money, but not profits

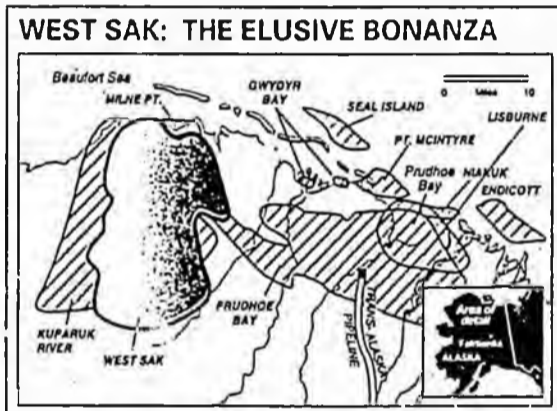
By BRIAN O'DONOGHUE  
Staff Writer

Like mythic knights tugging on the sword in the stone, North Slope oil producers keep reaching, without payoff, for the tantalizing rewards locked in the shallow sands of Alaska's West Sak.

"There's a couple billion barrels of that heavy oil in place. That's a pretty big target," said Al Hastings, who worked for Conoco during that producer's costly pilot project tapping the gigantic field of thick, cold crude.

BP Exploration recently estimated West Sak might contain as much as 16 billion barrels of heavy oil. This July Arco executive Scott Kerr told a congressional committee the formation's "oil-in-place exceeds 10 billion barrels, which makes it larger than the Kuparuk field but smaller than Prudhoe Bay."

The staggering size of West Sak, and the similar Ugnu sands, has caused some environmentalists to view the North Slope's heavy oil formations as sleeping giants, whose development could offset Prudhoe's declining production. Those opposed to permitting exploration inside the Arctic National Wildlife Refuge point to West Sak's proven reservoir as a



Source: Arco Alaska and BP Exploration

ready alternative source of oil needed to keep the trans-Alaska pipeline in business.

But producers, who've already lost hundreds of millions on West Sak, and state experts say the costs and technological problems associated with the Slope's heavy oil formations make recovery prospects speculative at best. "Even under our most optimistic scenario," Kerr said, "we anticipate oil reserves in the range of a half billion barrels—a significant number but substantially less than the giant fields to which West Sak is often compared."

Alaska's oil and gas division shares that cautious assessment.

"We look at it as a big resource but not a big proven reserve," said division petroleum

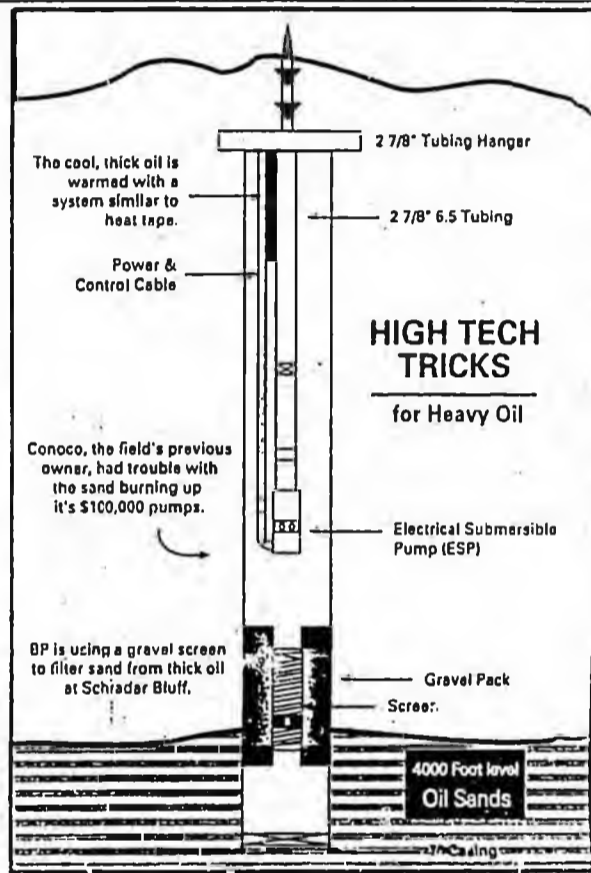
expert Bill Van Dyke. "It's a lot of oil and there is some production, but the individual wells just don't produce at a very high rate."

**Money down the hole**

Beginning in 1981 Arco spent nine years and some \$200 million sinking 13 wells into West Sak. The company pumped more than a million barrels of oil, before admitting defeat, Kerr told the Senate Natural Resources Committee.

"The pilot project was a technical success but an economic failure," he said. "The cost... was too high to continue production from even the best part of the West Sak formation. The pilot was abandoned in 1986 and production never resumed."

By all accounts, the best commercial prospects reside in the



Source: BP

eastern portions of West Sak's 300-square-mile field, where the oily sands rest 4,000 to 4,500 feet below the surface, or about 3,000 feet above Kuparuk. Conoco and, more recently, BP Exploration, have attempted to cash in on the heavy oil using their Milne Point facility to sink wells into the section of the field known as Schrader Bluff.

"It's deeper in the ground, so the temperature is a little warmer," BP's field asset ma-

nager, Howard Mayson, said of the heavy oil accessible through Milne's wells. "So it flows a little easier."

But any advantage is relative, Mayson said. Even in BP's sweet corner, West Sak's heavy oil "flows 40 times worse than Prudhoe Bay."

Conoco's \$126 million Schrader Bluff investment started pumping in 1991. At its height, the project's 22 wells

See OIL, Page A-7

## Dividend time: when dreams become reality

By ROSANNE PAGANO  
Associated Press Writer

ANCHORAGE—The calendar says autumn but for Alaskans it's the windfall time of year, when permanent fund dividends arrive and—if you're Ambler writer Nick Jans—visions of Visqueen dance through your head.

"Basically, my dividend check defrayed the packing and loading costs for the air charter that all my building supplies came in on," said Jans, a magazine columnist and nature book author

who teaches school during the day, writes at night and builds his new house in between.

The charter itself cost \$13,000, Jans said. The home, with its tongue-and-groove flooring, cutaway loft and view of the Kobuk River headwaters, ought to be ready by Thanksgiving. "This," he says, "is a real house."

The annual dividend—which this year totals \$990—is the stuff Alaska's dreams are made on.

State surveys show that about half of us use the check, paid

every year since 1980, to cover day-to-day bills. Nearly two-thirds say they'll save some, while nearly one-in-four Alaskans say they spend, spend, spend it all.

Among the spenders: Explorers Norman and Carolyn Muegge Vaughan, who are chipping away at debt from their antarctic treks. Among the savers: U.S. Sen. Ted Stevens, whose family puts their checks toward a college fund for 14-year-old daughter, Lilly.

"My dividend is going right into the dog barn," said top-ranking Iditarod Trail musher DeeDee Jonrowe.

The building at Jonrowe's Willow kennel is a just-finished two-story affair, with an apartment for her dog handler above and a warm sleeping area for her team below.

"I'm so excited," Jonrowe said at the prospect of being able to keep her arthritic dogs comfy in the 24-foot-by-24-foot insulated barn. "Last year, I had as many

as six dogs in the garage part of the house. This year, I built them their own building."

A bit of basking is what former Anchorage school board member Theresa Obermeyer has in mind with her family's six checks—one each for her and her husband, Tom, and their four children, aged 9 to 13.

Obermeyer says last year she parlayed the dividends into MarkAir travel coupons, but the move made her somewhat unpopular. See DREAMS, Page A-7

INSIDE

## Supply of pumpkins

## Great pumpkin

# OIL: Giant West Sak draws money

Continued from Page A-1  
 added a grand total of 3,300 barrels a day to the company's Milne Point production. The effort was undermined by a costly series of equipment breakdowns. The worst problems arose with the submersible pumps inserted at the bottom of the well shafts to force the thick oil to the surface.

"Conoco's pumps were lasting from one day to a couple of months," said Bruce Policky, exploitation manager of BP Exploration, which bought out Conoco's Milne Point investment in 1993. "Sand would come in, just plug up the pump, and the motor would burn out."

Each of the long narrow 150 horsepower pumps is "worth the better part of \$100,000," according to Mayson. The dollar-value of that loss is magnified by the difficulty of inserting replacements deep in the well. "So that's why you want them to last as long as you can."

Conoco's appetite for West Sak oil was curbed by the continuing pump failures. "We needed about a two-year-pump run to keep costs down for a chance at being economic," recalled Hastings, who now serves as oil and gas director for CIRI, a regional for-profit native corporation.

Schrader Bluff chief John Dillon is one of several Conoco employees who stayed on with BP when the field changed hands. "We've had the benefit of all of their mistakes," he said. "It's all part of the learning curve."

BP's team has managed to boost Milne's heavy oil production to about 4,000 barrels a day, with individual wells now averaging about 200 barrels daily, or less than one-third the output of most Kuparuk wells. A mixture of new and old tricks is evident in BP's current West Sak effort.

A warming device, similar to heat tape, prevents freeze ups as the thick oil passes through some 2,000 feet of permafrost. Gravel filters inserted at the bottom of each well restrain the sands like a coffee filter.

"We haven't had a (pump) failure since we've been running the field," Mayson said. "We have two wells where the pumps are approaching five years. We'd like to see five year runs be the rule of the day."

Individual well completion has shown improvement from blasting water down into the formation, a technique known as Fracpack, which penetrates and opens a pathway for the oil's removal, Policky said. "All of that sand fractures and creates an interstate highway back to the well."

Schrader Bluff's operators are considering other innovations, including injection of bacteria, Dillon said. "The idea is to put friendly bugs down into wells and see if we can change some of the oil qualities."

Bugs hit the goo  
 The slope's heavy oil isn't just colder than the crude presently filling the pipeline. Even at room temperature, West Sak oil is thick and viscous, less gassy and

possessing fewer so-called lighter petroleum ends. These qualities are due, in part, to a bio-degradation process, which Dillon attributes to "bugs" naturally present in West Sak's shallow formation. "The lighter ends of the oil are being attacked by bacteria. Essentially the bugs are eating and enjoying themselves at your expense."

Not only is heavy oil more difficult to extract, it yields less gasoline and other premium products, reducing its value to Slope producer's by about 60-cents-a-barrel. "More of it ends up as heating oil," Mayson said.

Given the investment disincentives, some lawmakers are talking about cutting producers a break on Alaska's heavy-oil. Rep. Joe Green, R-Anchorage, has introduced legislation to declare a "royalty holiday" qualifying wells.

"There's a significant reserve of heavy oil if we can make it more profitable," Green said. "There might be more interest from producers if they knew they could recoup their investment faster, say, in a 4-5 year period."

Green's bill is scheduled for a hearing later this month.

The state's natural resources chief, John Shively, said heavy oil formations are suited to the royalty adjustments lawmakers authorized last session.

"We developed the royalty incentive bill with things like West Sak in mind," Shively said. "It's a well-delineated pool, where you could look at the economics and make a decision. Developing technology might allow the state to capture the up side as well, the commissioner noted, referring to the provisions for raising royalties if a marginal field becomes a money maker."

Richard Fineberg, an independent North Slope environmental

and oil policy analyst, contends that producers downplayed West Sak's potential in their recent congressional testimony to strengthen arguments that ANWR oil is needed to shore up the viability of the trans-Alaska pipeline.

"Given all the problems it (West Sak) faces, Arco first said prices had to be \$35 per barrel," Fineberg noted. "Then it was \$25. Now at \$20 they're looking at it again. Why do we presume they can't overcome the barriers?"

Journalist Debbie Miller, who covers North Slope oil issues and opposes ANWR development, urged Congress to heed the bullish assessment from Occidental, one of BP's Schrader Bluff partners.

"The West Sak formation is a sleeping giant," Miller told Sen. Frank Murkowski's committee. "If the reason for invading the refuge is to find oil, we've already found it near Prudhoe Bay."

Arco is weighing a new West Sak pilot project, spokesman Ronnie Chappell said last week. "No decision's been made. We're at the point in our planning cycle where people are putting forward their projects for next year's spending."

But Mayson cautions that no one, including BP, has proven that money can be made on West Sak oil.

"Arco and Conoco spent more than \$120 million apiece. Essentially they lost that money and we haven't made a go of it yet," Mayson said. "In early 1997 we'll come to the decision point on whether or not we can make the case for the next level of production."

"I personally think that if we don't make a go of it, major companies will go cold on West Sak for the next decade."

# DREAMS PUMPKIN: S

Continued from Page A-1  
 ular when the airline quit flying in Alaska. "This year, I want to go to Hawaii," she said. "That really sounds fun."

Sitka-based detective novel writer John Straley has sun on his mind, too, but wouldn't dare move from rainy Southeast and risk losing the inspiration for his books.

Straley, who's lived in Sitka since 1977 and has received every dividend issued from Alaska's oil-wealth savings account, says this year he's investing in ultra-bright lights that ward off dark thoughts brought on by Alaska's dark winters.

Usually, the family's checks go into general income. "This year, I'm going to buy lamps," said Straley, who's at work on a second book for Bantam publishing. "If that doesn't work, I just might get a whole collection of aloha shirts and shorts and walk around town in them. I always get gloomy in wintertime."

In Juneau, Susan Knowles says family rules don't change just because her husband was elected governor. This year's checks will once again go into an education savings account for the couple's three children.

"There's usually a bit of discussion," Knowles said Friday as she recalled the wedding she and Gov. Tony Knowles waded through each year when the children report how their friends are allowed to spend \$50, or \$100, or \$200 out of their dividend.

Continued from Page A-1  
 pollen, bees took a long break from the heat, and heat-stressed flowers didn't want to open, Eastburn explained. The result was fewer pumpkins, or small ones that were easily devoured by fungi.

A killing frost Sept. 23 did in a lot of the late-setting fruit, he added.

There's one bit of comfort, he noted. The canning pumpkins used for Thanksgiving pies are a different species and weren't hit as hard.

In other big pumpkin states such as Pennsylvania and New York, the large growers who invested in irrigation made it through the summer, averting an out-and-out shortage. Still, pumpkins are generally smaller and more expensive, because of the lower yields and higher production costs.

"I know from some of the things I've seen on the national level that they are evidently in short supply across the country," said Bill Troxell, executive secretary of the Pennsylvania Vegetable Growers Association. "We certainly aren't going to have any

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# Advisers see Alaska's oil output rising

Legislature's consultants say marginal North Slope fields likely to offset decline after 2000

By IAN MADER  
The Associated Press

JUNEAU — The legislature's oil consultant gave lawmakers a surprisingly bullish report Wednesday about Alaska's oil-producing potential during the coming decade.

Massachusetts-based Cambridge Energy Research Associates told law-

makers it would be possible for Alaska to produce more oil in 2005 than today.

State oil economist Chuck Logsdon said the report probably took into account a trend toward greater tax and royalty relief for oil companies.

But industry critics said the forecast may show that

■ **SURPRISES UNLIKELY:** Analysts predict stable North Slope crude prices for the year. **D-1**

royalty giveaways proposed by Gov. Tony Knowles and many lawmakers are not needed to make marginal Alaska oil fields feasible.

Cambridge indicated Alaska's current decline in production likely would be offset by new production potential between 2000 and 2010 from North Slope oil fields currently deemed marginal, such as Badami Bay and West Sac.

In a presentation to House and Senate finance committees, Cambridge oil

expert Ann-Louise Hittle showed lawmakers graphs indicating a surge in potential North Slope production starting in 2002. Production would peak in 2005 at a rate somewhat higher than this year, before beginning another decline.

"All the graphs I've ever seen have lines just going straight down. This one

goes down and then up," said Sen. Tim Kelly, R-Anchorage, who saw the graphs but not the presentation. "It's certainly good news for Alaska."

Hittle said company forecasts involve assessments of world oil supply and demand, and technol-

Please see Back Page, OIL

## OIL: Legislature's consultant gives bright view of future production

Continued from Page A-1

logical advances.

After checking with Cambridge officials, Hittle declined to tell a reporter whether the forecast took into account proposed changes in Alaska's royalty structure, or whether the production likely would become profitable even without such royalty breaks.

"I do not want to get involved in politics," Hittle said. "I don't want to answer your question."

Oil companies, the Knowles administration and many state lawmakers currently agree that companies need royalty breaks in order to make production possible at several Alaska oil fields.

Royalty, now usually at 12.5 percent, is the oil that companies must turn over

to the state in return for producing here, in addition to excise and income taxes.

Bills introduced by Knowles and amended by lawmakers would give the natural resources commissioner wide authority to temporarily or permanently reduce royalty, on a case-by-case basis, as low as zero.

What the state sacrifices in revenue it would gain by guaranteeing oil-industry jobs for Alaskans, Knowles says.

Rep. David Finkelstein, D-Anchorage, said the Cambridge forecast was good news for Alaska, but that it increased his skepticism about aspects of the royalty legislation.

"It makes it doubly clear to me that we don't need to allow royalty reduction to go down to zero, ever."

*Oil companies, the Knowles administration and many state lawmakers agree that companies need royalty breaks in order to make production possible at several Alaska oil fields.*

Richard Fineberg, oil adviser to former Gov. Steve Cowper and a critic of the royalty proposals, said Cambridge may not have considered royalty changes in its forecast.

"In the past they have tended to not factor in current Alaska political dialogue," Fineberg said.

Fineberg has testified that Alaska oil production — which gives the state about 85 percent of its annual revenues — is not in as severe a decline as is traditionally assumed. He

maintains oil companies exaggerate their need for royalty reduction.

"The wolves cry only when they think they can frighten you and get rewards out of that fright," Fineberg said. "Here, the legislature's own consultant is coming in with forecasts that are even more optimistic than mine. It's forecasts like this that lead us to want to see a substantive case being made for royalty relief, rather than rhetoric."

On one chart in the Cambridge report, total Alaska

production potential is pegged at 1.71 million barrels per day this year, 1.35 million in 2000 and 1.73 million in 2005.

Another chart indicates in a footnote that production figures for 2005 assume development of Badami Bay, West Sak, North Star, Gwydyr Bay, Point Thompson, Hammerhead, Tern Island and Colville Delta fields.

Production and infrastructure at Badami would be a key to developing many other fields on the list, Hittle told lawmakers.

BP Exploration (Alaska) Inc., majority owner of Badami, has so far been unsuccessful in its attempts to get royalty breaks it says would be needed to make that field workable. Company spokesman Jim Palmer said a royalty break would

be just one of many factors that must fall in place before the field could begin producing.

"If this stuff's going to come on, why do you need the incentives? Well, to say that this is going to come on regardless of other variables would be absurd," Palmer said. "It's more complicated than that."

Logsdon, the state oil economist, said Cambridge probably did not consider specific bills before the legislature. But he said the company likely would have assumed there would be some tax and royalty breaks for oil companies in coming years.

"When they forecast, it's mostly trend extrapolation. If the trend is governments reviewing changes on the tax side — well, that's going on everywhere," Logsdon said.

b  
(9)

HOUSE COMMITTEE REPORT

Date Referred to Committee: January 24, 1996

FURTHER REFERRALS:

2/7/96  
Finance

Date of Committee Action: 2/7/96

The RESOURCES Committee considered:

HB 325

HOUSE BILL NO. 325

ROYALTY SUSPENSION: N. SLOPE HEAVY OIL

"An Act authorizing suspension of payment of a portion of the royalty due the state for initial production of heavy oil from wells on the Arctic Slope."

recommends it be replaced with the following committee substitute CSHB 325 (0+6) [ ] the same title [X] a new title

[ ] additional referral to \_\_\_\_\_ Committee  
[ ] attached amendment(s)

ADOPTS: \_\_\_\_\_ Letter of Intent

ATTACHES NEW FISCAL NOTE(S): (Dept) APPROVES PREVIOUS: (Dept/Date)  
[ ] fiscal note(s) \_\_\_\_\_ (2) [X] fiscal note(s) REU, DNR  
1/24/96

[ ] zero fiscal note(s) \_\_\_\_\_ [ ] zero fiscal note(s) \_\_\_\_\_

SIGNING WITH RECOMMENDATIONS	DP	DNP	NR	AM
<i>Nicholia</i> Nicholia				X
<i>DAVIES</i> DAVIES				X
<i>Williams</i> Williams	✓			
<i>Green</i> Green	✓			
<i>Austerman</i> Austerman	✓			
<i>Kott</i> Kott	✓			
<i>Ogan</i> Ogan	✓			
	(5)			(2)

CO-CHAIR'S SIGNATURE *Joseph Green*

# HOUSE COMMITTEE REPORT

(7)

Date Referred: April 28, 1995

FURTHER REFERRALS:

Resources  
Finance

Date of Committee Action: 1/23/96

The HOUSE SPECIAL COMMITTEE ON OIL AND GAS Committee considered:

HB 325

HOUSE BILL NO. 325

ROYALTY SUSPENSION: N. SLOPE HEAVY OIL

"An Act authorizing suspension of payment of a portion of the royalty due the state for initial production of heavy oil from wells on the Arctic Slope."

recommends it be replaced with the following committee substitute CS HB 325 (046)  the same title  a new title

additional referral to \_\_\_\_\_ Committee

attached amendment(s)

ADOPTS: \_\_\_\_\_ Letter of Intent

ATTACHES NEW FISCAL NOTE(S): (Dept)

APPROVES PREVIOUS: (Dept/Date)

fiscal note(s) (1) DNR (2) DOR

fiscal note(s) \_\_\_\_\_

zero fiscal note(s) \_\_\_\_\_

zero fiscal note(s) \_\_\_\_\_

SIGNING WITH RECOMMENDATIONS	DP	DNP	NR	AM
<i>Scott Degan</i>	✓			
<i>Nancy K. Kelly</i>	✓			
<i>Elizabeth Williams</i>	X			
<i>James L. ...</i>			✓	
<i>Robert ...</i>	X			
<i>insd ...</i>		X		
<i>Bette Davis by Shirley ...</i>	X			

CHAIR'S SIGNATURE *Nancy K. Kelly* 1-23-96

1 HOUSE SPECIAL COMMITTEE ON OIL & GAS

2 January 23, 1996, 9:00 a.m.

3 Tape 1, Side A

4 REP. ROKEBERG: Present are Norman Rokeberg chairman,  
5 Representative Gary Davis, Representative Bill Williams,  
6 Representative Scott Ogan, and Bettye are you on line, can you  
7 hear us?

8 REP. B. DAVIS: Yes I am.

9 REP. ROKEBERG: Representative Bettye Davis at the  
10 Anchorage LIO and thanks for being here Bettye.

11 REP. B. DAVIS: You bet.

12 REP. ROKEBERG: We have a quorum of the Oil and Gas  
13 Committee that is present.

14 REP. BRICE: Mr. Chair I'd like to be recognized as being  
15 here as well.

16 REP. ROKEBERG: I'm sorry, my apologies Tom. Mr. Tom  
17 Brice is also here. Good. I need new glasses. Tom I didn't  
18 get that right, right.

19 REP. BRICE: I'll let it go this time.

20 REP. ROKEBERG: Right, sorry to -- on the calendar today  
21 we have House Bill 325 authorizing suspension of payment of a  
22 portion of royalty due the state for initial production of  
23 heavy oil from wells on the Arctic Slope. On teleconference  
24 today we have Representative Bettye Davis and hopefully Chuck  
25 Logsdon from the Department of Revenue and Mr. Ken Boyd of the  
-- Director of Oil -- the Oil and Gas Division.

1 [THIS PORTION NOT REQUESTED]

2 Tape 1, Side B

3 REP. ROKEBERG: . . . The Chair recognizes the attendance  
4 of Representative Finkelstein at 10:05. Good morning Dave.  
5 Thank you Mr. Phillipi. Bev Ward did you have short statement?

6 MS. WARD: Actually Mr. Chairman we hadn't planned to  
7 read it aloud. It is the same testimony that we gave in  
8 November and we made copies for the Representatives of that.  
9 We still support the bill with small changes (indiscernible).

10 REP. ROKEBERG: Thank you very much. Mr. Ken Boyd, the  
11 Director of Oil and Gas, are you online sir?

12 (Via teleconference)

13 MR. BOYD: Yes Mr. Chairman.

14 REP. ROKEBERG: Would you please proceed with your  
15 testimony, sir?

16 MR. BOYD: Yes, Mr. Chairman. For the record my name is  
17 Ken Boyd. I'm the Director, Division of Oil and Gas. Now Mr.  
18 Chairman I was going to do a voice check to you. Am I coming  
19 through loud and clear, too loud and clear, or what?

20 REP. ROKEBERG: No it's pretty good, a little choppy but  
21 we can hear you.

22 MR. BOYD: All right, again we'll move a little bit  
23 closer to the mike. With me is (indiscernible - cuts out).....

24 REP. ROKEBERG: That's too loud.

25 MR. BOYD: . . . . with the Department of Law, Bill Van  
Dyke, Petroleum Manager and Mike Kotowski who is the Unit

1 Manager. Both Bill and Mike are petroleum engineers with the  
2 Division of Oil and Gas.

3 Mr. Chairman, we just have a couple of comments. The  
4 committee needs to realize that this bill will result in -- in  
5 no royalty for five years per well and there will be no taxes.  
6 The bill doesn't provide for any clear and convincing showing  
7 or any economic analysis. If you recall last year in the  
8 debate with HB 207 we spent a lot of time talking about the  
9 standards we needed to grant royalty relief and one of the  
10 things we talked about a lot was to be able to -- the need  
11 really to show -- to have a clear and convincing showing that a  
12 company needs this royalty relief.

13 The presentation by OXY and -- and -- and BP does not  
14 provide an economic analysis. It does provide some numbers and  
15 some assumptions I presume. I don't know that these  
16 assumptions would be the same for any other operator on the  
17 North Slope. And even if you make the assumption that this is  
18 need then there's no basis for the term selected to cure this  
19 assumed need. The \$15 netback, the 5 year term, the \$500  
20 barrels are all picked but with no -- no basis selected. And  
21 it also would assume that, I presume, that the economics for  
22 all the companies are the same for every field. Having said  
23 that there are some unintended consequences, I think, here. Do  
24 these same assumptions hold that the heavy oil lake of Prudhoe  
25 Bay, the heavy oil of the Kuparuk field, and West Sak, heavy  
oil of Bedombi (ph), and Point Thompson. These fields also

1 contain heavy oil and this bill the way it's crafted applies to  
2 all those fields, yet you've heard testimony from no one on  
3 anything except Schrader bluff. There is clearly no assurance  
4 that the companies will do anything at all at least at Schrader  
5 bluff. There certainly is no assurance that they'll do  
6 anything after five years. There's no assurance that  
7 additional royalty relief wouldn't be sought after the fifth  
8 year. In short, Mr. Chairman, the administration's position is  
9 we believe HB 207 is a better vehicle to craft royalty  
10 reductions. You can do a clear and convincing and detailed  
11 economic analysis to determine need. I am not saying there  
12 isn't a need or that it isn't a valuable tool. There is  
13 nothing (indiscernible) to do. I'm just -- all I'm saying is  
14 that we -- you've picked a bunch of assumptions and made a  
15 bunch of assumptions with no basis. So the Department's and  
16 administration's position is we believe that HB 207 remains the  
17 -- the -- the tool to use for royalty reductions. Thank you  
18 Mr. Chairman. Mr. Chairman, I think as far as I -- just one  
19 more thing. If you want some more specifics we talked about  
20 what is a well and to side track accounts and dates. I don't  
21 know that the assurance of somebody testimony -- testifying,  
22 one company gives us much assurance that in fact side tracks,  
23 or multilaterals or other wells are not in fact separate wells.  
24 So I just wanted to add that. We have some other assumptions  
25 in our bill analysis. I won't get into the details but we're  
here to answer any questions the committee might have.

1 REP. ROKEBERG: Does anybody else on your phone hook up,  
2 Mr. Boyd, that wants to testify from your Department?

3 MR. BOYD: No, Mr. Chairman. We'll -- we'll be available  
4 to answer any questions but somebody else may have something to  
5 say at that time.

6 REP. ROKEBERG: Are there questions of Mr. Boyd?  
7 Representative Finkelstein.

8 REP. FINKELSTEIN: Thank you, Mr. Chairman. Mr. Boyd I'm  
9 -- I'm not as confident as I wasn't at the November hearing, I  
10 was out of town. The -- in the -- in the discussions you've  
11 had about this has anyone pointed out any provisions of the  
12 royalty reduction law we have in place now that won't  
13 adequately address these situations? I realize there's a floor  
14 in some cases but other than that minor difference is there  
15 anything else out there that has been pointed out that would --  
16 would arguably keep the royalty reduction provision from being  
17 used?

18 MR. BOYD: Mr. Chairman, Representative Finkelstein, the  
19 floor is right. I mean we believe the 3 percent floor -- you  
20 know -- at the maximum, it depends on how you look at it as a  
21 whole. The other provisions that would not work at least --  
22 for OXY and only OXY would -- would be the provision under the  
23 settlement of the royalty reductions that I believe Mr. Benton  
24 referred to earlier, he said there would be no -- no effect.  
25 Well the effect would be that this bill -- (indiscernible)  
after this bill they would not be able to use HB 207. Our

1 leases that were changed from 20 percent to 12 and a half and I  
2 think that was 7, these -- the bill as presented here, of  
3 course gets rid of that provision and they would be able to use  
4 it. So I guess the one piece that they wouldn't -- wouldn't be  
5 able to use would be to use bi-oxydental on those  
6 (indiscernible).

7 REP. FINKELSTEIN: Thank you Mr. Chairman.

8 REP. ROKEBERG: Other questions of Mr. Boyd? Mr. Boyd  
9 the fiscal note you provided, could you walk us through your  
10 methodology on that? I'll get it out here. Let's see here,  
11 this is the one that you're estimating a per well change in  
12 revenues of \$228,000 per well per year.

13 MR. BOYD: Yes, Mr. Chairman. What we did was take the  
14 500 barrel per day maximum multiply it by 12-1/2 percent  
15 royalty rate multiply it times a net factor of \$10 a barrel  
16 multiplied by 365 days a year. It's just a -- a benchmark. It  
17 -- it just --- it just sets a number that shows what the  
18 royalty -- what's the royalty --- what's the royalty the state  
19 would not collect per well over that period of time.

20 REP. ROKEBERG: But if there are no wells are drilled  
21 here we're not losing anything, is that correct?

22 MR. BOYD: That's correct.

23 REP. ROKEBERG: So this isn't even the half a loaf we're  
24 talking about under 207, this is a zip loaf or something?  
25 Would that be a fair analysis?

1 MR. BOYD: I have no guarantee and you have received no  
2 guarantee that any wells would be drilled no matter what you do  
3 under any bill or any provision of anything.

4 REP. ROKEBERG: Do -- Representative Williams?

5 REP. WILLIAMS: Yeah what did you call -- first I'd like  
6 to get either something written from your office on your  
7 reasons about why 207 would go along with this to take care of  
8 heavy oil.

9 MR. BOYD: Mr. Chairman, Representative Williams, I beg  
10 your pardon if I've interrupted you but you're breaking up.

11 REP. ROKEBERG: Speak up Bill.

12 REP. WILLIAMS: I would first of all like something  
13 written from your office stating why 207 would -- how 207 would  
14 affect the -- the heavy oil. I have a question and answer  
15 about heavy oil that the five-year royalty suspension from --  
16 in the white paper which I haven't had a chance to study. As  
17 far as saying that after five years or during the five years  
18 that the -- we will be able to assure -- be assured that ARCO,  
19 or BP, or any oil company out there that would like to come in,  
20 there's no -- there's no guarantee in -- in anything. Well I  
21 guess the old saying the only guarantee we have is taxes and  
22 death, what type of guarantee are you talking about?

23 MR. BOYD: Mr. Chairman and Representative Williams I  
24 talk to you about no guarantee either. I'm saying that HB 207  
25 says that we can to allow for production that would not  
economic -- otherwise be economically feasible and it goes on,

1 it doesn't limit it to heavy oil or not to heavy oil It just  
2 allows the commissioner to make that determination based on a  
3 real economic analysis. If at the end of the day we may craft  
4 something that still doesn't provide them any need or we may  
5 provide them the need and they still may not develop it. I  
6 mean they said here if you had this bill which they claim will  
7 give them the relief they seek that they still may not develop  
8 the field.

9 REP. WILLIAMS: They're not -- is -- they are not  
10 developing the field today?

11 MR. BOYD: But they are working on the field today,  
12 Representative Williams. I mean they are drilling wells and  
13 they are making production what I'm saying is under 207 if they  
14 see the need all 207 does is remember from the long -- the long  
15 years we've had is -- is a mechanism for the state to look at  
16 the numbers on which their assumptions are based and then craft  
17 some sort (indiscernible - speakerphone covered by paper)

18 REP. WILLIAMS: Would you -- will you be able to get me  
19 something written on your reasons why the -- 207 would affect  
20 -- would work in this area?

21 MR. BOYD: I can do it Representative Williams.

22 REP. WILLIAMS: Okay and I guess going back to BP's paper  
23 here, The Risk of Project Development Delay, would 207 affect  
24 any of this -- this area? Do you have BP's explana -- paper in  
25 front of you? It's a . . . . .

MR. BOYD: I do Representative Williams.

1 REP. WILLIAMS: Okay, the last page of Risk of Project  
2 Development Delay, would . . . . .

3 MR. BOYD: The last page?

4 REP. WILLIAMS: Yes. And on top of it it has the Risk of  
5 Project Development Delay. Would 207 delay anything in this  
6 area from -- according to their operating. . . . .

7 MR. BOYD: Mr. Chair and Representative Williams, I mean  
8 there would be the application process and the analysis process  
9 which takes time.

10 REP. WILLIAMS: How -- how much time?

11 MR. BOYD: It's hard to say. It depends on how clear and  
12 convincing their argument is right out of the box, whether we  
13 use consultants, perhaps, to come in and -- you know --- time  
14 is money here. With more people doing analysis, we have a  
15 limited staff, I would say 3 to 6 months, and that's a guess.

16 REP. ROKEBERG: Further questions? Representative  
17 Finkelstein.

18 REP. FINKELSTEIN: Thank you Mr. Chairman. Mr. Boyd,  
19 what's the entire history of applications from the industry  
20 under either the old royalty reduction provisions or the new  
21 ones for reductions for these type of fields?

22 MR. BOYD: Mr. Chairman and Representative Finkelstein I  
23 don't have that exact -- that information in front of me. As I  
24 recall there were several applications in Cook Inlet, Texaco,  
25 Marathon comes to mind.

REP. FINKELSTEIN: For the . . . . .

1 MR. BOYD: Beg your pardon, Mr. Chairman, stand by. I  
2 have some

3 REP. FINKELSTEIN: Well could I -- I'll make the  
4 question simpler. How about for North Slope fields what's --  
5 how many times have the companies applied for royalty reduction  
6 under the old provisions or the new provisions?

7 MR. BOYD: Well Mr. Chairman, Representative Finkelstein,  
8 just one, the Conoco/Oxy application of some years ago.

9 REP. FINKELSTEIN: And -- and no one has applied under  
10 the new provisions yet to see how they will work and what the  
11 time frame will be?

12 MR. BOYD: Mr. Chairman, Representative Finkelstein,  
13 that's correct nobody has applied.

14 REP. FINKELSTEIN: Okay, thank you Mr. Chairman.

15 REP. ROKEBERG: Mr. Boyd, the follow up on that question.  
16 As I recall of the -- of the -- actually few but several  
17 royalty reduction applications made under section (j) that  
18 there was never any -- the state has never granted any kind of  
19 a royalty reduction under the prior statutory regime, is that  
20 correct?

21 MR. BOYD: No, Mr. Chairman. We -- the royalty reduction  
22 was granted under the settlement actually on the -- I'm going  
23 to say seven leases are -- I'll say seven leases that Oxy has  
24 the reduction was to 20 percent and 12 percent with the  
25 provisions then they would not apply for -- again for a royalty  
reduction.

1 REP. ROKEBERG: Well I -- but even in Cook Inlet there  
2 was never a grant of royalty reduction is that correct?

3 MR. BOYD: There was never an application. I was  
4 mistaken, there was an application and then it was withdrawn.

5 REP. ROKEBERG: Withdrawn, that's correct. And -- and  
6 the victims of the other one are sitting here. Thank you very  
7 much. Any other questions? Representative Finkelstein.

8 REP. FINKELSTEIN: Thank you Mr. Chairman. But just to  
9 point out again we spent hours and hours debating those issues  
10 here, revised the law and we've now got new provisions that no  
11 applications have ever been submitted under. I just want to  
12 make sure that's the case.

13 REP. ROKEBERG: Well Mr. Boyd the way this statute is  
14 written it -- it is not discretionary on the part of the  
15 commissioner or does not require the Governor's approval, is  
16 that correct?

17 MR. BOYD: Mr. Chairman are you talking about HB 325?

18 REP. ROKEBERG: That's correct.

19 MR. BOYD: As far as I can tell, no.

20 REP. ROKEBERG: It's self-executing therefore your  
21 department nor even a company that would be -- come under the  
22 guise of this particular statute would not have to expend any  
23 money to review an application is that correct?

24 MR. BOYD: Mr. Chairman only the -- the administrative  
25 costs -- you know -- the way you have it crafted now with the  
-- the adding in the PTI index and some of those things but I

1 mean it's -- it -- I'd have to say it's a minor administrative  
2 cost.

3 REP. ROKEBERG: Yeah this is really basically self-  
4 executing. You know when you say -- you know -- you care to  
5 venture a guess what a six -- 3 to 6 month review of a 207  
6 application would cost just your department?

7 MR. BOYD: No, Mr. Chairman, I can't do that. I don't  
8 know the answer to that.

9 REP. ROKEBERG: Okay.

10 MR. BOYD: I don't know also what effect it would have on  
11 the state though if you did not do that sort of economic  
12 analysis.

13 REP. ROKEBERG: And further the analysis of the -- well  
14 the testimony today showed that the state stood to -- to gain  
15 some \$350 million in otherwise foregone royalties from this  
16 particular scheme. Would you buy into that type of analysis  
17 whether the numbers are exactly right but aren't the long-range  
18 potentials for further royalty revenues to the state greater  
19 under this particular bill than no bill at all?

20 MR. BOYD: Mr. Chairman, there are absolutely no way for  
21 me to answer that question.

22 REP. ROKEBERG: Any other questions of Mr. Boyd?  
23 Representative Finkelstein.

24 REP. FINKELSTEIN: Thank you Mr. Chairman. Just to get  
25 the theme behind this wasn't -- and I think Mr. Boyd you were  
one of the proponents of this theme last year, wasn't the theme

1 last year sort of when all these same questions came up that  
2 it's the ability of the administration with discretion under  
3 law to make these kinds of decisions. That every time I and  
4 others propose limitations on that discretion on the royalty  
5 reduction bill the response was no, that's better left to each  
6 situation, negotiations necessary and that that's what we have  
7 a Department of Natural Resources and a Division of Oil and Gas  
8 for? Wasn't that the theme last year and isn't that a little  
9 contradictory to what we're doing today?

10 MR. BOYD: Representative Finkelstein, I certainly hope  
11 not. What I'm saying is that it is specific in each instance  
12 and here is an instance. And I think it's proper now that this  
13 be done. I don't think we've ever testified to anything  
14 different under HB 207.

15 REP. FINKELSTEIN: Well -- well my argument is just it  
16 seems to me we're losing the ability that the legislature took  
17 on last year -- the legislature gave the department to make  
18 these kind of decisions that just sort of trust the department,  
19 we'll make good decisions which was the theme last year is now  
20 being lost in sort of turn it all over -- will eliminate any  
21 administrative discretion.

22 MR. BOYD: Mr. Chairman, Representative Finkelstein, I  
23 think that's absolutely true.

24 REP. FINKELSTEIN: Thank you Mr. Chairman.

25 REP. ROKEBERG: Thank you. Next we'd like to hear from  
Mr. Chuck Logsdon. Chuck are you on line there sir?

1 MR. LOGSDON: Yes, I'm here, Mr. Chairman.

2 REP. ROKEBERG: Well go ahead and give us your testimony,  
3 look forward to it please.

4 MR. LOGSDON: Okay. Really -- I didn't really have much  
5 to add what's been stated by Mr. Boyd of DNR. Our fiscal note  
6 is really done quite simply. It's based on what we were  
7 assuming in the fall of '94 -- fall '95 forecast for production  
8 and royalties from the straight or lost production. The  
9 production assumptions that we used bear as closely as possible  
10 the current development plans of the industry and they're based  
11 on direct communications with the involved developers and  
12 public statements and we do have access to some proprietary  
13 data. The negative fiscal note really just reflects what would  
14 happen if we were to redo the forecast with those same  
15 development plans what the heavy oil would be exempt from  
16 royalties. And that's what the revenue in fact issue is based  
17 upon. That's really all I have to say about the bill, Mr.  
18 Chairman, and I can be available to answer any questions,  
19 obviously.

20 REP. ROKEBERG: So your -- your note -- fiscal note of a  
21 negative 50 some million dollars is really prospective and  
22 based on the development plans that were provided by BP. Is  
23 that correct?

24 MR. LOGSDON: I can expect it -- that we were -- that we  
25 had the ability to obtain that kind of information, yes.

1           REP. ROKEBERG:     And the -- but they don't include  
2 potential development of 230 additional wells over a period of  
3 7 to 9 years on the -- just the Schrader bluff alone. Is that  
4 -- that correct, you didn't take that into account?

5           MR. LOGSDON:     That's correct.

6           REP. ROKEBERG:     Now you've heard testimony here today  
7 that the -- the prospective revenues of some \$60 million should  
8 be as much as \$425 if this legislation went forward and the  
9 field investment did take place as contemplated in the Schrader  
10 bluff area. Do you -- would you agree that that would be at  
11 least a -- a fair analysis of the potential revenue gains in  
12 the future if this amount of development took place?

13          MR. LOGSDON:     I really haven't had the opportunity to  
14 evaluate that -- the -- those -- those assumptions and I -- it  
15 would be, I think, premature of me to comment on whether or not  
16 that number is accurate until we have a chance to look at the  
17 assumptions.

18          REP. ROKEBERG:     Well I understand that but just in the  
19 terms of it conceptually don't we know our priority that that's  
20 going to happen, that we're going to gain more here if in fact  
21 they go ahead with their development?

22          MR. LOGSDON:     Well -- you know -- I mean the issues is,  
23 of course, fraught with uncertainty and oil prices would  
24 probably be the main driver of the whole induction decision  
25 anyway and just try to estimate the revenue you would -- you  
would have to have some consensus about where you thought oil

1 prices were going. And I -- I believe that this is just one of  
2 those unanswerable type questions. It makes this kind of  
3 analysis question so very difficult. Certainly you could come  
4 up with a scenario which would underpin that -- that number  
5 see, just as you suggested but whether would be my own personal  
6 best guess or whether it fell in within the range. I don't  
7 know that that's -- that -- I -- I have just -- am unprepared  
8 to answer that.

9 REP. ROKEBERG: Other questions? Representative  
10 Finkelstein?

11 REP. FINKELSTEIN: Thank you Mr. Chairman. I -- I know  
12 too that your question requires the assumption that HB 207's  
13 provisions don't work because if they do work then -- then  
14 there would be some return to the state under the status quo.  
15 Mr. Logsdon on a broader economic analysis one of the arguments  
16 that's being made is even if there's no return to the state and  
17 even if we will make less than we will under the royalty  
18 reduction provisions in current law that somehow this will be  
19 good because it's going to bring about all this activity and  
20 even in the short term, we're going to make money somehow  
21 because we're going to have more activity going on. Have --  
22 does your department get involved at all -- I suppose --  
23 suppose that you don't, on looking at what other benefits are  
24 out there? Because obviously you don't make any money on  
25 income tax, obviously we don't make any money on sales tax,  
isn't in the bigger sense this new generated activity if there

1 is no income to the state from any royalties or taxes isn't it  
2 a net loss in pub -- public services provided?

3 MR. LOGSDON: Mr. Chairman, Representative Finkelstein, I  
4 actually we are very tightly focused on strictly the petroleum  
5 revenue issue. Obviously the study that was done by Doctor  
6 Goldsmith and others have made estimates of what heavy oil  
7 development could mean in terms of their overall economic  
8 impact. I -- we have just not -- we have not looked at that  
9 generally speaking -- we're -- that the focus has been very  
10 tightly on the impact on the petroleum revenue side.

11 REP. FINKELSTEIN: Thank you Mr. Chairman.

12 REP. ROKEBERG: Mr. Logsdon in the committee substitute,  
13 I'm not sure you had an opportunity to look at that, but it  
14 sets forward a well-head price of \$15 which is I believe the  
15 reported royalty value type of a number. Could -- would you  
16 care to comment on that as a circuit breaker price for  
17 suspension of the -- any -- any royalty exemption and you --  
18 would you agree that that would be a -- a fair price to use?

19 MR. LOGSDON: Mr. Chairman, I -- I believe that it is  
20 that kind of modification that would be appropriate to preserve  
21 a blanket five-year type royalty holiday for any production and  
22 -- and I also believe that it's -- you know -- it's possible  
23 that these sorts of royalty modifications should -- could be  
24 accomplished under the -- through the Department of Natural  
25 Resources but certainly that -- that would be a step in a  
direction that would truncate the risk the state would have for

1 instance in a case of a price slide which occurred for a  
2 lengthy period of time during the five-year holiday.

3 REP. ROKEBERG: And do you think the \$15 -- does that  
4 relate to like the federal \$24 WTI price and could that be a  
5 pretty fair comparison.

6 MR. LOGSDON: Compared to -- what is it -- what's the  
7 federal government's cap again?

8 REP. ROKEBERG: \$24 WTI.

9 MR. LOGSDON: Okay, well let's see -- that would take us  
10 to -- actually it would be -- that would actually be a probably  
11 in -- in the ball park considering the -- the quality of the  
12 heavy oil and the additional transportation costs to -- to move  
13 it to the pipeline and the entire pipeline tariff, that's  
14 probably in the ball park of the number that's somewhat  
15 consistent with the federal cap.

16 REP. ROKEBERG: And just one last thing, there -- there's  
17 a difference between the fall forecast for '95 and the spring  
18 forecast, particularly relates to the -- the peripheral smaller  
19 fields including Schrader bluff as pointed out for the  
20 committee members on page 3 of the white paper. Would you care  
21 to comment on the different methodology used?

22 MR. LOGSDON: I -- as far -- I -- I don't have the -- I  
23 don't have that white paper in front of me, as far as I know  
24 the -- the difference between the spring and the fall would be  
25 a function of any adjustments made in -- in the development  
schedule for the Schrader bluffs is a result of our

1 investigation into the development planning for that -- that  
2 particular field.

3 REP. ROKEBERG: Very good. Further questions of Mr.  
4 Logsdon? Hearing none, thank you very much sir, appreciate  
5 your testimony.

6 [END OF REQUESTED PORTION]

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# What is "heavy oil"?

- Low gravity
- Thick
- Produces slowly over a long period of time
- Disadvantaged in market place
- Capital intensive
- A focus of current debate on oil and gas incentives

# Previous Heavy Oil Development

## ARCO/West Sak Project

- *Spent \$135 Million on 13 wells and facilities*
- *Average producing rate = 250 BOPD per well*
- *Expected Recovery = 1 million barrels*
- *Total Investment = \$135/Barrel*
- *Uneconomical*

# Previous Heavy Oil Experience

Conoco/Tract 14

- *Spent a minimum of \$126 Million on 22 wells, pads, etc.*
- *Average producing rate = 275 BOPD per well*
- *Expected Recovery = 13.5 Million Barrels*
- *Total Investment = \$9.30/BBL*
- *Uneconomical*

Source: SPE 30289, "Milne Point Schrader Bluff: Finding the Keys to Two Billion Barrels", 6/95. Reserves determined from decline curve analysis.

# Suspension Incentives in Other Jurisdictions

- Texas
  - high-cost gas (10 year exemption)
- Utah
  - wildcat wells (first 12 months)
  - development wells (first 6 months)
- Oklahoma
  - horizontal wells (until payout)
  - enhanced oil recovery projects (until payout)
- Montana
  - horizontal wells (first 18 months)
- Mississippi
  - discovery wells (first 5 years)
  - re-activated wells (first 3 years)
- Kansas
  - tertiary projects (for life of project)
  - shallow wells (for life of project)
  - discovery wells (first 12 years)
- Arkansas
  - discovery wells (first 5 years)

SPE 30289



## Milne Point Schrader Bluff: Finding the Keys to Two Billion Barrels

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\* SPE Member

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### ABSTRACT

Milne Point, North Slope Alaska, contains in excess of 2 billion barrels original oil in place (OOIP) in the shallow, Late Cretaceous, Schrader Bluff Formation. This resource is part of a larger accumulation in excess of 26 billion barrels OOIP overlying many of the deeper producing fields. A small waterflood pilot presently produces 3300 barrels of oil per day (BOPD) of 19 API oil from 2650 acres in Milne Point. Initial average well productivity's of 350 BOPD, low by North Slope standards, coupled with current cost, performance, and fiscal conditions, render the resource uneconomic. A multi-pronged approach dealing with well productivity, drilling and facility costs, and development incentives is underway to save this resource from abandonment. Technological and contractual innovations are considered keys to success. Which keys fit the lock will determine the development of billions of barrels of recoverable oil.

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Illustrations at end of paper

### INTRODUCTION

Milne Point is located approximately twelve miles west of Prudhoe Bay on the North Slope of Alaska (Figure No. 1). BPXA acquired Milne Point from the majority owners, CONOCO and Chevron, and began operating the field on 1 January, 1994. Occidental Petroleum continues to maintain a minority working interest in the field. The field currently produces 28,000 BOPD primarily from the Kuparuk Formation, one of the main North Slope reservoirs. The Schrader Bluff accumulation overlies this deeper horizon. BPXA has initiated a significant challenge to commercialize this Schrader Bluff reservoir following earlier attempts by CONOCO at Milne and by ARCO to the south and west of Milne, in the reservoir interval known informally as West Sak.

### THE RESOURCE

The shallow Schrader Bluff/West Sak/Ugnu reservoirs overlie the main reservoirs at the Kuparuk River, Milne Point, and Prudhoe Bay fields. With 26 billion barrels of oil in place, these shallow pools are larger than the North Slope's Prudhoe Bay. The Milne Point portion of this resource (Figure No. 2), the subject of this paper, consists of a stacked sequence of

reservoirs with variable oil water contacts and variable API gravities, covering over 32,000 acres (50 square miles). This challenging reservoir is one of the largest undeveloped accumulations in North America, and with even modest recoveries, reserves must be considered substantial.

### SHALLOW SAND NORTH SLOPE HISTORY

The Schrader Bluff discovery well at Milne Point, Kavearak Point 32-25, was drilled by Standard Oil of California with partners, Mobil and Phillips in mid-1969. Although a deeper horizon was tested, the shallower intervals were only logged. Additional drilling concentrated on the deeper horizons, but the accumulations were considered uneconomic until the CONOCO partnership crystallized and committed to development in the early 1980's. Milne Point #1 was the first to test the shallower interval, yielding 125 BOPD of 19 degree API oil by drill stem test. The partnership developed the deeper Kuparuk Formation starting in 1985, leaving the Schrader Bluff until later.

Arco's West Sak pilot at the Kuparuk River Unit attempted to produce from roughly the stratigraphic equivalent of Milne Point's Schrader Bluff. Commencing production in September 1984, an estimated \$135 million was invested in 13 wells and processing facilities. Significant additional investments were made in reservoir studies and project design. The production wells averaged 120 BOPD without stimulation and about 250 BOPD after fracture stimulation. About 0.8 MM barrels were recovered before the pilot was abandoned in December 1986. Difficult reservoir fluid properties (high oil viscosity), unconsolidated sands, and low completion efficiency contributed to the project's low productivity.

CONOCO's Schrader Bluff pilot at the Milne Point commenced production in March 1991. The pilot was producing about 3,300 BOPD at the end of 1993 when BP acquired the Milne Point Unit. At this point, the 12 producers averaged 275 BOPD/well of 19 degree API gravity crude and about 3 MM barrels had been

recovered. Approximately \$126 million had been invested in 22 wells, four pads, road power lines, and pipelines. As with the West Sak pilot, this project lost money and failed to meet key development hurdles for commercial viability: sufficient well productivity at low capital costs.

### RESERVOIR CHARACTERISTICS

The Schrader Bluff consists of Late Cretaceous near shore marine sand sequences, informally referred to as the "N" and "O" sands. The individual reservoir units are predominantly very fine to fine grained, moderately sorted unconsolidated quartz sands with varying amounts of accessory minerals, mainly rock fragments, mica and glauconite. The reservoir units are amalgamations of storm deposited and redistributed, for the most part, below wave base. Bioturbation, and burrows are common in some intervals whereas, others display fine laminated bedding, suggesting more rapid sedimentation. Calcareous interbeds are locally common, often associated with concentrations of bivalve debris.

The upper "N" sands consist of multiple reservoir layers varying in thickness between 5 and 15 feet, with permeabilities ranging between 5 millidarcies to 5 darcies. The lower "O" sands consist of two main sand bodies that although are finer grained than the "N" sands are generally more massive and competent. These sands are more continuous and are more correlative across the North Slope than the thinner, more discontinuous "N" interval. The "O" sands thickness varies between 10 to 35 feet with permeabilities between 10 millidarcies and 1 darcy. The average porosity in all sand units varies between 25 to 28 percent.

The formation dips gently north-northeast at a rate of approximately 170 ft per mile. The resulting monocline is broken by numerous faults of variable displacement, most of which trend north-northeast and progressively downdrop the reservoir to the northeast. Depths range from 3500 feet - 4500 feet. Faults generally producing offsets between 20-150 feet compartmentalize the reservoir to some

degree. This coupled with stratigraphic discontinuities, can hydraulically isolate individual reservoir units.

The fracture gradient is between 0.66-0.70 psi/ft with an overburden stress gradient of 0.85 psi/ft. The estimated net confining stress is between 1000 to 1300 psi.

### OIL CHARACTERISTICS

The Schrader Bluff Pool is understaturated by about 500 psi and correspondingly has no gas cap. The initial average reservoir pressure is 1750 psig at 4000 ft true vertical depth subsea with an average reservoir temperature of 81°F. These pressures are only slightly higher than the local hydrostatic pressures. Currently, the average reservoir pressure is between 1400 to 1750 psi depending on producing fault block.

The hydrocarbon quality varies between the N and O sands, the deeper O sand containing a better-quality crude than the N sand. The N sand oil gravities range from 14° to 19° API with viscosities between 40 and 140 centipoise(cp). The oil gravities and viscosities improve in the O sands, oil gravities typically falling between 18° to 21.5° API with viscosities from 30 to 45 cp. Figure No. 3 shows the anticipated API gravity variations across the Schrader Bluff formation.

In general, the PVT properties of the Schrader Bluff hydrocarbons bear a resemblance to conventional heavy oil systems, namely:

- low API gravities (14-22°),
- low gas oil ratio(GOR)(100-200 scf/stb),
- low oil formation volume factor (about 1.04-1.08 rbbl/stb),
- high average viscosity (30 to 70 cp at original conditions).

The live oils of the Schrader Bluff are dominated by the C7+ fractions (67 mole percent on average). This corresponds to an exceedingly small amount of C2-C6 intermediate hydrocarbons and suggests high biodegradation. The hydrocarbons contain no hydrogen sulfide, and very little quantities of carbon dioxide or nitrogen. The gas

composition is primarily methane. The formation water contains approximately 27,000 ppm total dissolved solids, with an average salinity of 20,000 ppm NaCl equivalent.

In common with fluid systems from shallow and soft sands, the Schrader Bluff hydrocarbon properties exhibit significant variations across sand bodies. This variance is seen vertically, from sand to sand, and laterally within one sand as it is traced down dip. The mapped variance is poorly understood at this time.

### PRESENT DEVELOPMENT

A localized Tract 14 pilot project was initiated in 1991, developing approximately 2560 acres (Figure No. 2). Roads, pipelines and general facilities to support 4 pads were constructed and presently support 23 deviated wells (Figure No. 4). A limited waterflood was initiated in March 1992. The reservoir is currently developed on a spacing that varies from 160 acre to 80 acres. It is anticipated that development will be ultimately be equal to, or less than, 80 acres.

### RESERVOIR / FIELD PERFORMANCE

#### Drilling

Drilling and completion costs comprise one of the major cost levers being aggressively worked. Historical drilling and completion costs averaged \$2.3 MM per well. Changes in the casing program have resulted in significant cost reductions. Current drill and completion costs average \$1.6 MM, a 30 percent savings. Work is underway to reduce these costs further.

#### Completions

Typical completion design includes 2 7/8" tubing with an electrical submersible pump (ESP) and a wellbore heat trace system preventing freezing in the permafrost section of the wellbore. (Figure No. 5). Sand control methods are required to insure long ESP run lives. Wells where O-sands have not been controlled have produced varying quantities of sand, leading to premature ESP failures.

Gravel packs, pre-packed screens, and frac-packed sand control techniques have been

employed to determine the most cost effective and least damaging completion. The future challenge is to improve frac-packing technology and reduce completion costs.

### **Offtake History**

Commercial production from Schrader Bluff began in March 1991. Waterflood was initiated in March 1992 in four different fault blocks when several production wells were converted to water injectors and two additional injectors were drilled. There are twenty three (23) wells in Tract 14 region; 2 horizontal producers, 15 active conventional producers, of which 4 are shut-in because of ESP failures, 5 injectors and 1 well that was never completed due to faulted section.

Initial production averaged approximately 350 BOPD. The initial gas oil ratio averaged 180 scf/stb with watercuts generally less than 1 percent. Currently, the average production rate is 200 BOPD per well with an average GOR of 450 scf/stb. The watercut has increased to 14 percent. The most productive wells of the field have cumulative volumes of 0.5 MMstbo. Cumulative production to date is approximately 4.1 MMstbo representing approximately 1.4 percent of original oil in place within the Tract 14 region. The field decline rate is 6 percent per year (Figure No. 6).

Completion designs limit reservoir surveillance activities. Therefore, alternative data acquisition methods are used. For example, RFT pressures are obtained in the Schrader Bluff from wells drilled to the deeper Kuparuk formation. This pressure information provides valuable data for monitoring depletion in the different sands.

### **Reserves**

Reservoir volumetric analysis quantifying oil in place, as complex as it might be, is one of the more straight forward estimations regarding the Schrader Bluff. Actual reservoir connectivity due to stratigraphy and sedimentology, as well as structural compartmentalization, complicate the picture. Therefore, sweep efficiency will be highly variable and in some areas, ineffective.

Additional efforts are focused on quantifying the effects of three drive mechanisms providing energy to the reservoir: solution gas compaction, and water drives. Initial performance is attributed to solution gas drive, followed by contributions from compaction and water support. The ultimate necessity and timing of waterflood support is considered key to large-scale planning.

Milne Point's Schrader Bluff contains more than 2 billion barrels of oil. The Schrader Bluff, over the entire North Slope, contains more than 16 billion barrels. An additional 10 billion barrels resides in the informally named Ugnu sands overlying the Schrader Bluff. The oils in this unit have progressively lower API gravities corresponding to increased bio-degradation. The associated higher viscosities, coupled with the lower temperatures as one approaches the permafrost at 1500-2000 feet, renders recoveries from this resource more problematic.

Assuming waterflood support, and limiting production to existing producers, modeling indicates recoveries exceeding 16 percent. Applying these recoveries to original oil in place yields greater than 320 MMstbo with fieldwide development. This first generation model will be replaced with a more refined simulator being developed to assist in reservoir evaluation, planning and maintenance.

### **EOR Recoveries**

The reservoir and oil characteristics of the Schrader Bluff make it a prime candidate for various enhanced oil recovery (EOR) projects. Among the methods that have passed initial screening are Air Injection (In-situ Combustion), various floods, such as CO<sub>2</sub> or natural gas liquid projects, and to a lesser degree, steam flooding. Each of these methods has its own advantages and disadvantages, with varying probabilities of success. Several methods might ultimately be employed in different parts of the field, depending upon local reservoir and oil character.

Scoping models of these processes yield possible incremental recoveries from 12-40 percent over those recovered by waterflood.

These models indicate that air injection yields the highest recoveries, although capital costs for compressors, facilities, and well completions are anticipated to be significant. Extremely tight environmental compliance on the North Slope is another significant consideration in what processes ultimately move from modeling to field testing.

### **CHALLENGES**

Presently, the Schrader Bluff and the total shallow oil accumulation of 26 billion barrels in the greater North Slope area, do not favorably compete for international development funds. Contributing factors are: elevated North Slope facility and drilling costs; costs associated with environmental protection, presently inflexible fiscal terms; all coupled with production rates, low by North Slope standards. The combination yields net rates of return and paybacks that are unattractive under current economic conditions.

Assuming constant economic factors such as royalty rates, and oil prices, main challenges to unlocking large-scale development include:

- 1) driving down front end capital costs associated with drilling and facilities to levels, comparable with Canadian and northern tier Lower 48 operations, through design, operational innovations, and judicious contractual agreements,
- 2) accelerating initial production and modifying decline curves on a per well basis through innovative completion techniques and reservoir management,
- 3) maximizing ultimate recovery through reservoir management and to a lesser degree, enhanced oil recovery methods.

If such challenges can be met, the keys to success will have been found.

### **Costs**

Cost savings have already been realized in many areas including: casing programs, well head hardware, hydraulic fracture designs,

analysis of hole sizing, facilities design, piggybacking on existing facility designs, utilizing surplus equipment from other North Slope assets, pad design, fit for purpose rigs, logging costs, workover costs, and investigation of coil tubing completions.

In addition, general operating and overhead costs are prime targets for reduction. As an example, the workover cost of replacing a failed ESP, universally utilized at Milne Point, has been reduced by half. Furthermore, costs are expected to be reduced to one third of the original costs within the year. The frequency of ESP replacement, a significant operating expense, has also seen improvement with expected runlives increasing from 3 to 5 years.

### **Well Productivities**

Well productivities are primarily keyed to net pay, oil viscosity, completion design, and ESP runlives. Whereas, net pay and oil viscosity are variables somewhat beyond control, gains have been made in completion design, and all operational aspects of ESP's.

Recent innovative hydraulic fracture designs involving pumping large volumes in short time frames, achieving wide fracture width with minimal propagation, have yielded the highest productivity index to date. These rates, while pushing the envelope of existing equipment, have the potential of increasing initial production rates by a factor of 2 to 3.

### **Environmental Considerations**

Operations on the North Slope of Alaska are not "business as usual" when it comes to environmental concerns. In these times of heightened awareness, Milne Point is located in a place where this awareness is focused. Alaska contains a high percentage of our protected lands within the United States. Over 50 % of the total acreage devoted to Parks or Refuges fall within Alaska, and with this high concentration, goes a heightened responsibility. As stewards of the environment in which we work, we must be diligent in our protection of this resource. This stewardship comes with a cost, however, and this cost is substantial.

Due to land ownership, lease conditions, and legislation, the North Slope is regulated by three layers of government, the North Slope Borough, the State of Alaska, and the United States government. As a result, regulations must be followed, studies conducted, reports filed and permits obtained for each of these entities.

The nature of the tundra wetlands and its associated flora and fauna drives many aspects of operations, all to minimize impact: facility design, waste disposal, drill pad site selection, road construction, and timing of operations with regard to temperature and wildlife cycle. These costs are necessary for doing business in a responsible manner. But, the costs are considerable and put an additional economic burden upon any successful development. Being fully committed to our environmental responsibilities, and simultaneously striving to find keys to unlocking this resource, crystallizes an environmental challenge: finding ways to fully protect the environment by reducing the foot print, and thereby, reducing overall costs.

### PRESENT DEVELOPMENT PLANS

The 1995 Schrader Bluff program includes drilling as many as 5 wells from the existing Milne Point pad infrastructure to achieve higher production rates at lower drilling and completion costs. Non-conventional wells and large scale frac-packs are two examples of technologies under consideration to improve production rates. In addition, drilling and completion methods and costs are being challenged and alternative drilling fluids are being evaluated to minimize completion and formation damage.

In conjunction with this drilling program, a comprehensive reservoir and fluid study is underway to more fully understand performance. This work is fully cross-disciplinary and interlinks at many levels. (Figure No. 7) As well as integrating existing data, conventional core and downhole fluid samples are being taken to further this analysis. Much of this data will be the basis for a fullfield simulator being constructed to assist in reservoir management and evaluation.

Development scenarios for collection and processing facilities are being evaluated. The aim is to efficiently collect production from potentially hundreds of new wells, while increasing facility capacity to process the flowstreams. Several alternatives are under consideration, including debottlenecking the central processing plant and 'partial processing' of produced fluids at well pads.

The desire to minimize surface impact by centralized pad design dovetails with cost reduction. However, this drives up drilling costs and complicates field development, and maintenance, as it requires highly deviated wells. As the iterations involving development strategy, facility design and drilling costs are far from unique, choosing the final solution will be a challenge in its own right.

EOR processes are being screened and scoping analyses will be conducted to evaluate incremental recoveries. However, primary and secondary recovery, coupled with cost, are the main Schrader Bluff economic drivers. Enhanced oil recovery is not considered a key to unlocking the Schrader Bluff resource. As presented in this paper, the keys are closer at hand.

### ACKNOWLEDGMENTS

The authors wish to acknowledge Occidental Petroleum for granting permission to publish this material. Thanks go to the previous staff of CONOCO who saw the potential of the Schrader Bluff resource and went forward with the initial pilot project. Similarly, those within BP who have seen the potential and can see the path towards realization are acknowledged. Thanks also go to Craig Smalley, BP-Sunbury, for assistance rendered.

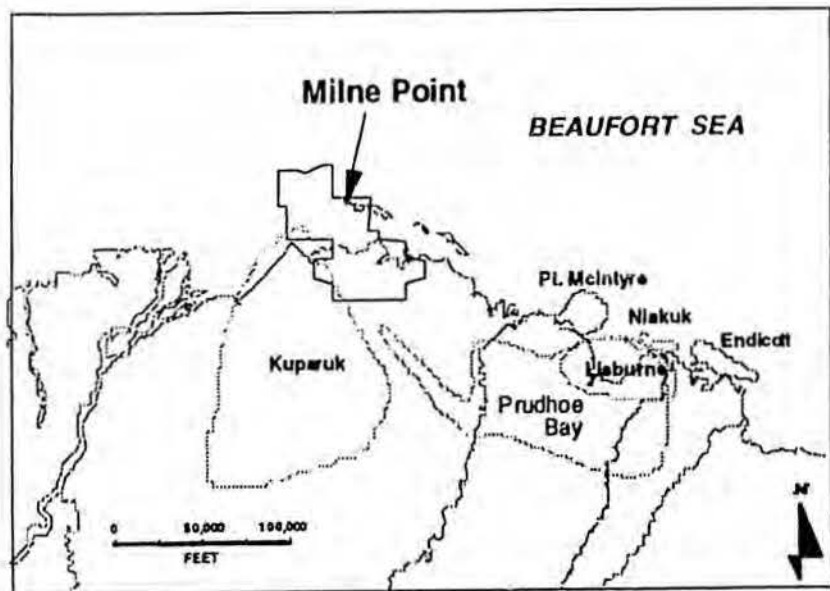


Figure 1 - Map of the North Slope of Alaska

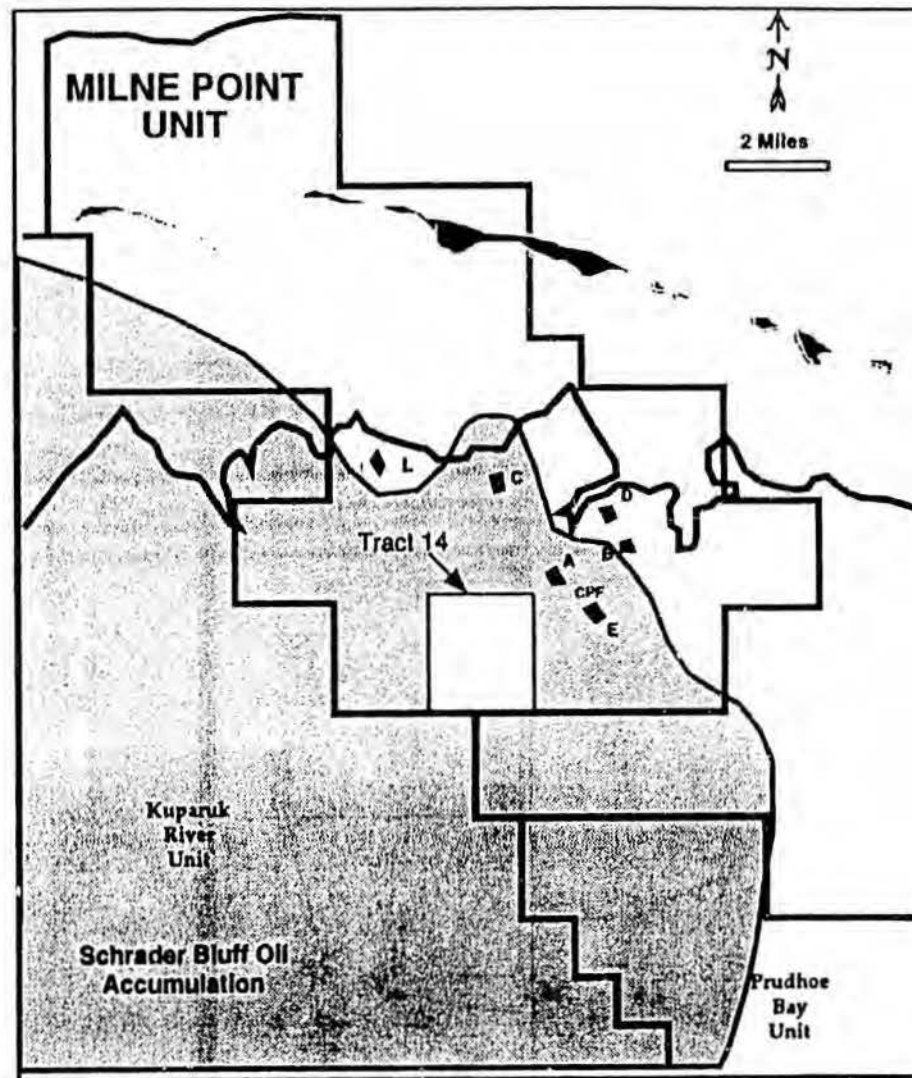


Figure 2 - Schrader Bluff Oil Accumulation

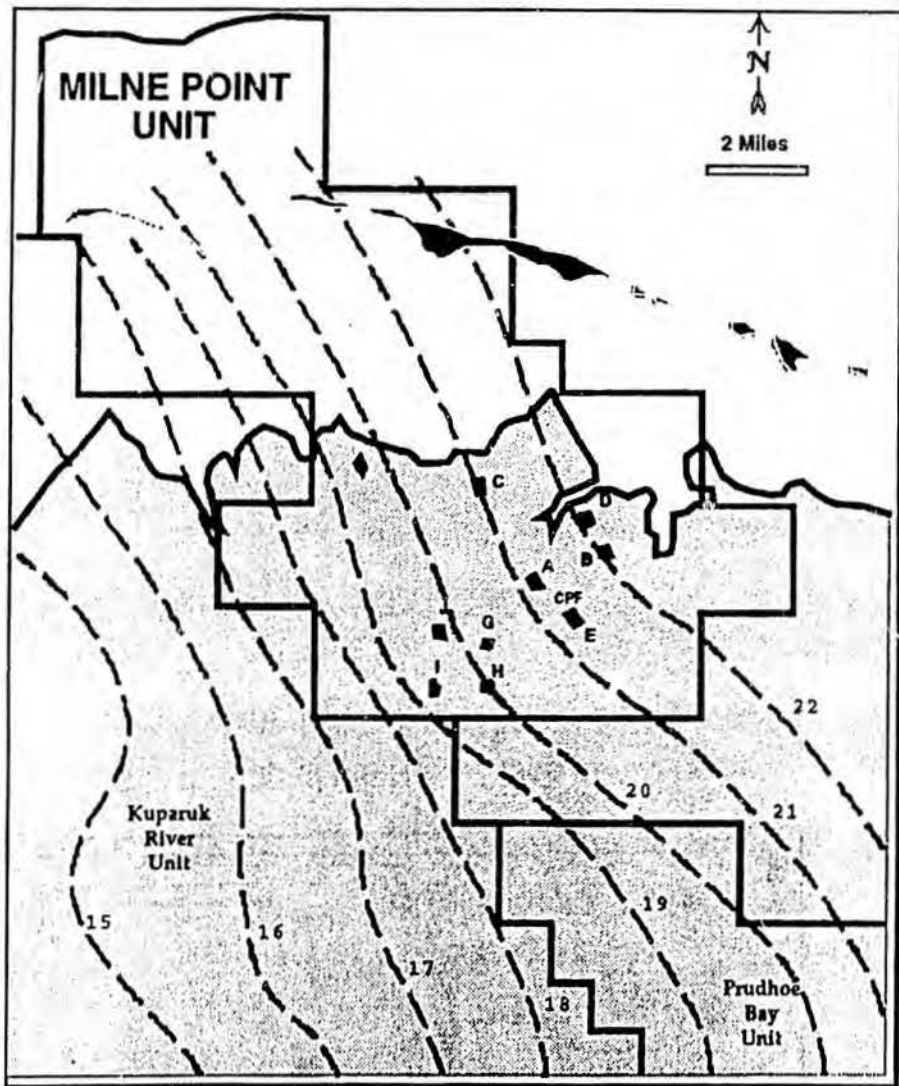


Figure 3 - Schrader Bluff API Gravity Map

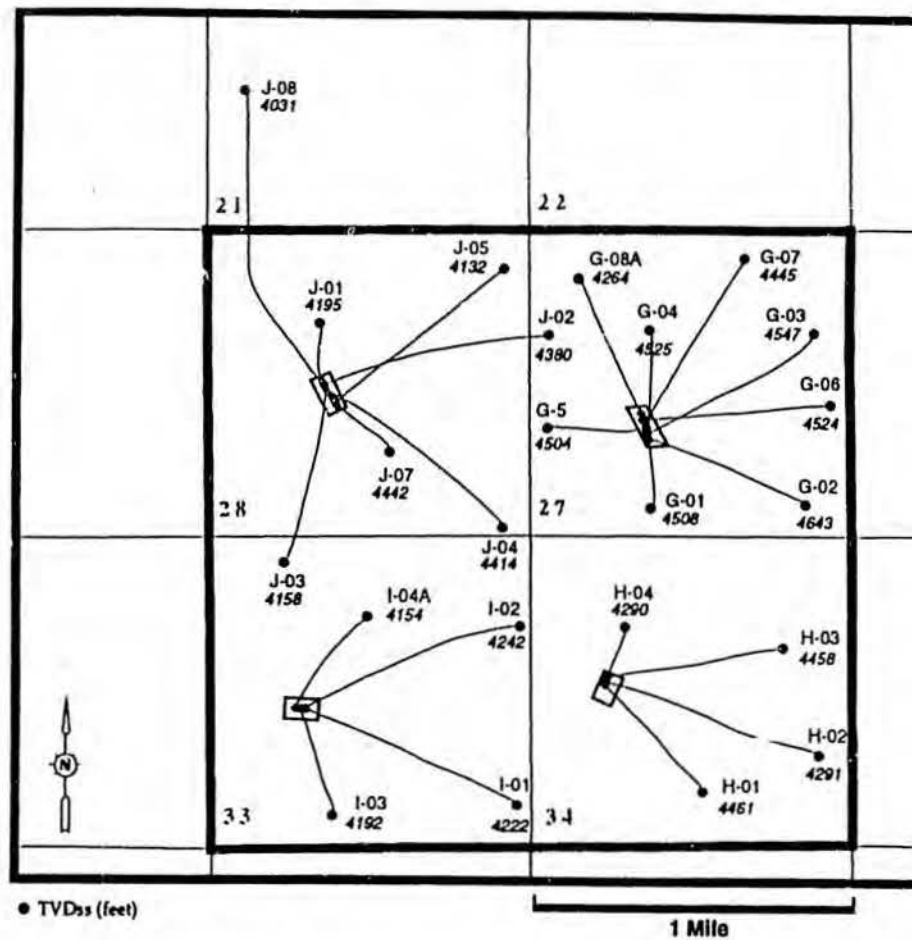


Figure 4 - Tract 14 Well Location Map

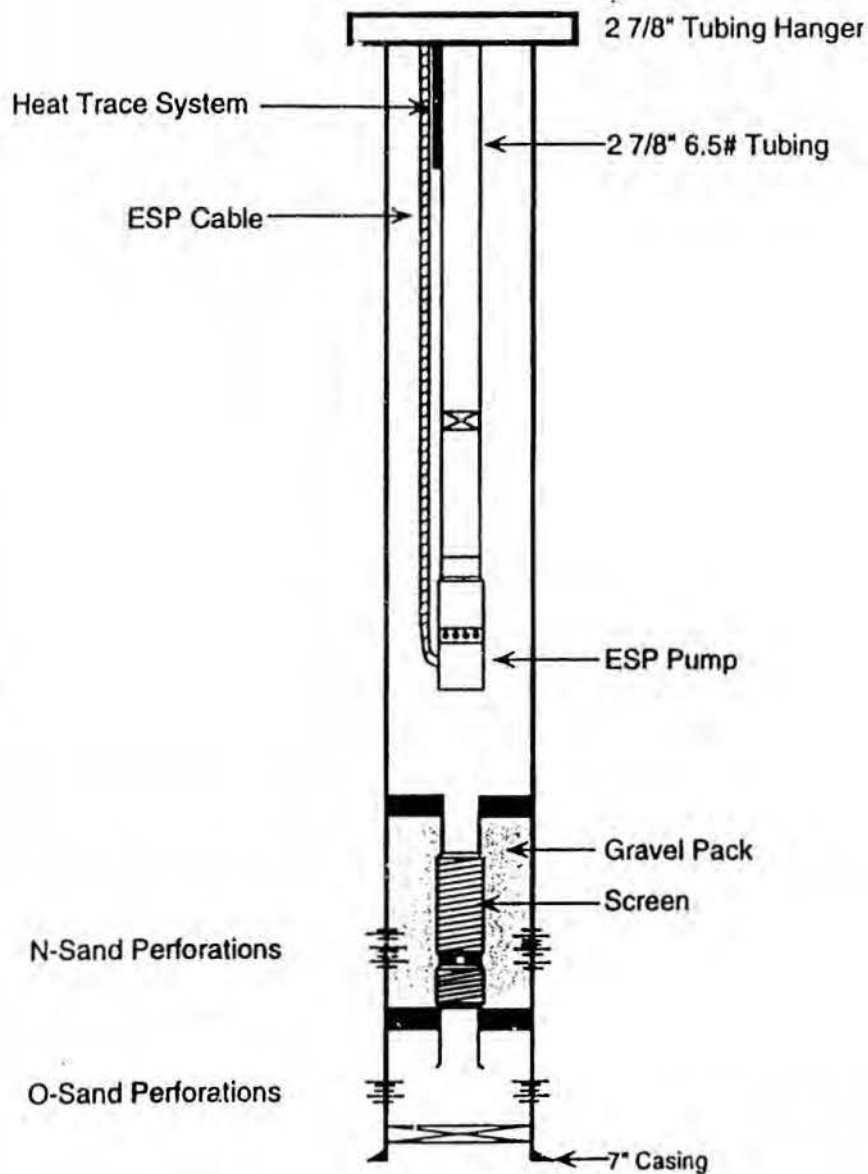


Figure 5 - Generic Schrader Bluff Completion

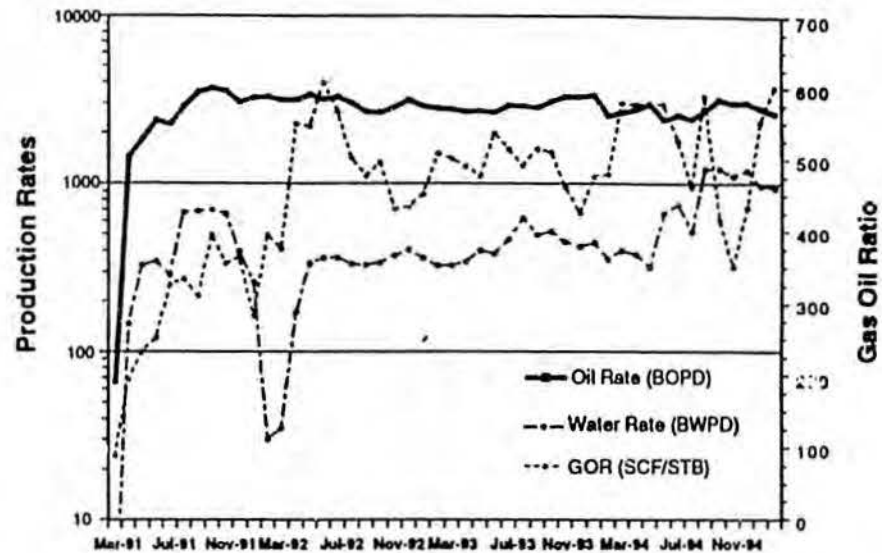


Figure 6 - Monthly Average Production History

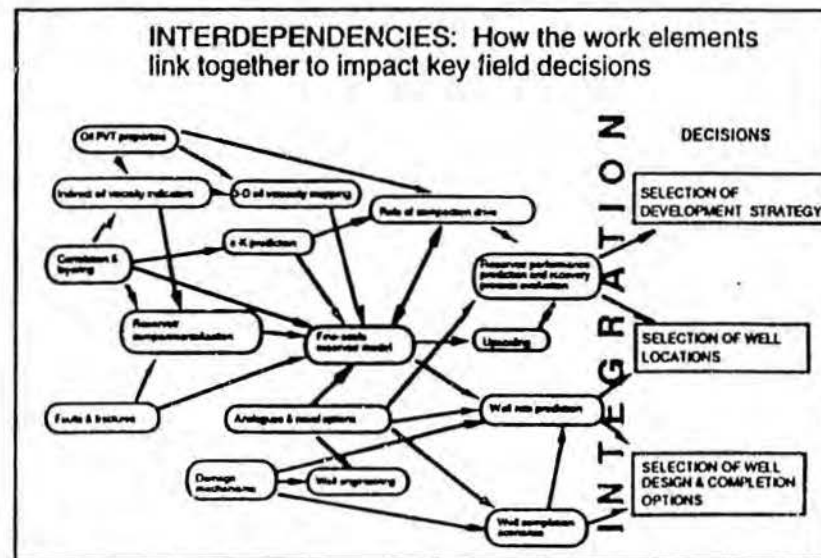


Figure 7 - Work Program Interdependencies

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January 16, 1996

Ms. Shirley Armstrong  
Office of Rep. Norman Rokeburg  
Room 110, State Capitol  
Juneau, Alaska 99801

Re: Enclosed Price Ceiling Examples  
Our File No.: 840.1

Dear Shirley:

Enclosed are the BLM and IRS incentive price ceiling examples that I mentioned to Rep. Rokeburg yesterday, and that he requested. I've marked the ceiling language in blue pen.

Sincerely,

SIMPSON, TILLINGHAST, SORENSEN & LORENSEN

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Jon K. Tillinghast

PAGE 1  
LEVEL 1 - 1 OF 3 DOCUMENTS

FEDERAL REGISTER  
Vol. 60, No. 116

Proposed Rules

DEPARTMENT OF THE INTERIOR (DOI)  
Bureau of Land Management (BLM)

43 CFR Part 3100

[WO-610-4110-02 1A]  
RIN 1004-AC26

Promotion of Development, Reduction of Royalty on Heavy Oil

60 FR 31663

DATE Friday, June 16, 1995

ACTION Notice of proposed rulemaking, notice of reopening of comment period

SUMMARY On April 10, 1995, the Bureau of Land Management (BLM) published in the Federal Register (60 FR 18081) a notice of proposed rulemaking to amend the regulations related to the waiver, suspension, or reduction of rental, royalty, or minimum royalty on "heavy oil" (crude oil with a gravity of less than 20 degrees). The notice allowed a comment period of 60 days, closing on June 9, 1995.

The Department of Energy (DOE) is currently developing new information on the potential impacts of the proposed rule. DOE is focusing particularly on the effects of raising the qualifying crude oil gravity to more than 20 degrees. In order to allow all interested parties sufficient time to review the new DOE information, BLM is reopening the comment period for an additional 30 days. Information on the DOE findings is available from Dr. John Bebout, at the address shown below under FOR FURTHER INFORMATION CONTACT.

DATES Comments should be submitted by July 17, 1995. Comments received or postmarked after the above date may not be considered in the decisionmaking process on the final rule.

ADDRESSES Comments should be sent to Director (140), Bureau of Land Management,

Room 5555, 1849 C Street, NW, Washington, DC 20240. Comments can also be sent to internet!WO140@attmail.com. Please include "attn: AC26" and your name and return address in your internet message. Comments will be available for public review at the above address during regular business hours (7:45 a.m. to 4:15 p.m.), Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Dr. John W. Bebout, Bureau of Land Management (310), 1849 C Street, NW, Washington, DC 20240 (202) 452-0340.

Micheal A. Ferguson,

Acting Assistant Director, Resource Use and Protection

60 FR 31663

[FR Doc 95-14785 Filed 6-15-95, 8 45 am]

BILLING CODE 4130-84-P

FEDERAL REGISTER  
Vol 60, No 68

Proposed Rules

DEPARTMENT OF THE INTERIOR (DOI)  
Bureau of Land Management (BLM)

43 CFR Part 3100

[WO-610-00-4110-2411]  
RIN 1004-AC26

Promotion of Development, Reduction of Royalty on Heavy Oil

60 FR 18081

DATE Monday, April 10, 1995

ACTION Proposed rule

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To view the next page, type np\* TRANSMIT  
To view a specific page, transmit p\* and the page number, e.g. p\*1  
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SUMMARY The Bureau of Land Management (BLM) is issuing this proposed rule to amend the regulations relating to the waiver, suspension, or reduction of rental, royalty, or minimum royalty. This amendment would establish 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. This action is being taken to 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. The BLM believes that this amendment will result in substantial additional revenue for the States and Federal Government, increase the cumulative amount of domestic oil production from existing wells, increase the percentage of oil recovery from presently developed reservoirs, minimize the necessity of drilling new wells with their additional environmental impacts, assist in reducing the national balance of trade deficit, and help promote stability in the jobs and

*Aimed @ existing heavy oil development*

services related to the domestic oil industry

**DATES** Comments should be submitted by June 9, 1995. Comments postmarked after this date may not be considered as part of the decisionmaking process in issuance of a final rule.

**ADDRESSES** Comments should be sent to Director (140), Bureau of Land Management, Room 5555, Main Interior Building, 1849 C Street, N.W., Washington, D.C. 20240. Comments will be available for public review in Room 5555 at the above address during regular business hours (7:45 a.m. to 4:15 p.m.), Monday through Friday.

60 FR 18081. \*

FOR FURTHER INFORMATION CONTACT: Dr. John W. Bebout, Bureau of Land Management,  
(202) 452-0340

**SUPPLEMENTARY INFORMATION:** 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. In order to encourage the greatest ultimate recovery of oil or gas and in the interest of conservation, the Secretary, upon a determination that it is necessary to promote development, or that a lease cannot be successfully operated under the terms provided therein, may reduce the royalty on an entire leasehold or any portion thereof. The provision concerning stripper well properties allows royalty reduction for properties that produce an average of less than 15 barrels of oil per eligible well per well-day.

The Bureau of Land Management (BLM) has reason to believe that additional royalty relief for producers of heavy crude oil may be necessary to maintain current levels of development, promote investment in enhanced recovery efforts, and encourage maximum recovery of the resource, thus warranting royalty reduction under Section 39 of the Mineral Leasing Act (30 U.S.C. 209).

Fluctuating oil prices, combined with high production costs, have resulted in an uncertain economic future for producers of low gravity crude oil. As recently as last January, California producers of heavy crude were spending between \$9 and \$10 to produce a barrel of crude oil that was typically selling for between \$8.50 and \$9 per barrel (from data provided by the Conservation Commission of California Oil and Gas Producers). When depreciation, depletion, and amortization costs were considered, nearly 69% of the state's production was uneconomic and more than 13,000 industry and industry-related jobs were at risk (California Independent Petroleum Association).

Heavy crude oil prices have recently risen to the point that the immediate crisis in California has passed. Many of the heavy oil properties remain only marginally economic, however, and are vulnerable to future down-turns in oil prices. As many as two-thirds of the marginal properties could be lost during a period of sustained low oil prices (National Petroleum Council Committee on Marginal Wells/Executive Summary-Draft). The danger in losing these wells is that, although production from individual wells may be small, their collective loss would be significant. The United States would lose the opportunity to take advantage of new technologies being developed by the Department of Energy (DOE) and industry, and the remaining recoverable reserves would be lost.

This proposed rule would preserve the contribution of marginal producers of heavy crude oil to the national reserve base. As a result of this relief, more wells should stay on line (even in periods of depressed oil prices), fewer recoverable reserves should be lost, and there will be less adverse economic impact on States and local communities.

The DOE has modeled the BLM's proposed royalty rate reduction for heavy crude oil. It is DOE's conclusion that the proposal will benefit all producers of heavy oil while remaining revenue neutral to all oil producing States except California (California contains the majority of the nation's heavy oil reserves). Assuming a West Texas Intermediate Crude oil price of \$ 20 per barrel—a price consistent with recent oil markets—the proposal can be expected to increase recoverable reserves in California by around 72 percent, from 132.8 million barrels to 228.5 million barrels.

5/24/11  
6 ms.

A provision of the proposed rule provides for the termination of individual royalty reductions should the average price of West Texas Intermediate Crude oil rise to a level greater than \$ 24 per barrel for a period of at least 6 consecutive months. This provision is intended to ensure that [13082] royalty relief is only provided during periods of low market prices

The proposed 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 measured 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

Rich - are there production rules?

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 proposed rule also provides for royalty rate reductions for stripper oil wells. Many provisions of this proposed rule are essentially the same as the provisions of the existing regulations that pertain to stripper wells, except that references to "stripper well" have been replaced with "heavy oil well." The similarity between the existing provisions pertaining to stripper wells and the provisions of this proposed rule could allow for some restructuring of section 43 CFR 3103.4-1 to reduce the overall regulatory text and to increase clarity. The public is invited to comment on whether reorganizing 43 CFR 3103.4-1 should be considered in preparing the final heavy oil royalty reduction rule.

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

It is hereby determined that this rule does not constitute 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 rule will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 et seq.). This is because the proposed royalty rate reduction is voluntary, requires no additional paperwork, and applies to all operators regardless of size. Additionally, the BLM has determined, under Executive Order 12630, that the rulemaking will not cause a taking of private property.

60 FR 18081, \*18082

The BLM has certified that these regulations meet the applicable standards provided in sections 2(a) and 2(b)(2) 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 1010-0090 and 1004-0145.

#### List of Subjects for 43 CFR Part 3100

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

On March 30, 1995, an outdated version of this proposed rule was published in the Federal Register (60 FR 16424) by mistake. That proposed rule publication is hereby withdrawn, and this version is published in its place.

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 proposed to be amended as set forth below.

#### 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. 351-359.

#### Subpart 3103--Fees, Rentals and Royalty

2. Section 3103.4-1 is amended by revising paragraph (b)(1), redesignating paragraph (e) as paragraph (g), and adding new paragraphs (e) and (f) to read as follows:

§ 3103.4-1 -- Waiver, suspension, or reduction of rental, royalty or minimum royalty

\* \* \* \* \*

(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 payor in the proper BLM office. It 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

\*\*\*\*\*

(e)(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) scale

(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

60 FR 18081, \*18082

entrained liquefiable hydrocarbons) or any completion producing oil and less than 60 MCF of gas per day

(f) 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/payor 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 communitization agreement number or the unit agreement name), the names of the operators for each lease, the calculated new royalty rate as determined under paragraph (f)(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 1994, the operator must submit Purchaser's Statements for July, August, and September of 1994.

(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 1994, the [\*18083] operator must submit Purchaser's Statements for the months of September 1993, and March and September 1994, 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/payor 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

$V[1]$  = Average Production (bbls) of Well #1 over the last 3 calendar months of sales

$V[2]$  = Average Production (bbls) of Well #2 over the last 3 calendar months of sales

$V[n]$  = Average Production (bbls) of each additional well ( $V[3]$ ,  $V[4]$ , etc ) over the last 3 calendar months of sales

$G[1]$  = Average Gravity (degrees) of oil produced from Well #1 over the last 3

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calendar months of sales

$G[2]$  = 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 ( $G[3]$ ,  $G[4]$ , 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 degrees API; Well #2, 6,000 bbls, 21 degrees API; Well #3, 2,000 bbls, 14 degrees 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 communitization agreement or a unit participating area, the weighted average API oil gravity for the lands dedicated to that specific communitization agreement or unit participating area must be determined in the manner prescribed in paragraph (f)(3) of this section and assigned to all property subject to Federal royalties in the communitization agreement or unit participating area

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

(i) Qualifying royalty rate determination

(A) The operator/payor 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 oil less than 3 times in their productive life may still qualify for this royalty rate reduction. However, no further reductions will be granted until the property has a sales history of at least 3 production months (see paragraph (f)(5)(iii) of this section).

(ii) Calculating the qualifying royalty rate. If the Federal leases or portions thereof (e.g., communitization or unit agreements) qualify as heavy oil property, the operator/payor must use the weighted average API gravity rounded down to the nearest 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	2.2
9	3.1

(b) FR 18081, \*18083

10	39
11	48
12	56
13	65
14	74
15	82
16	91
17	99
18	108
19	116
20	125

*Start declens @ 20°  
 HR 6.99 start @ 25° So.  
 API 19 → Royalty  
 11.6  
 4.52  
 BLM  
 11/6/99*

(iii) New royalty rate effective date. The new royalty rate will be effective on the first day of production 2 months after BLM receives notification by the operator payor. The rate will apply to all oil production from the property for the next 12 months. If the API oil gravity is 20 degrees or greater, the royalty rate will be the rate in the lease terms.

(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 payor must determine the weighted average API oil gravity for the property for that period. The operator/payor must then determine the royalty rate for the following year using the table in paragraph (f)(5)(ii) of this section.

(B) The operator/payor must compare the newly determined royalty rate to the initial qualifying royalty rate. The operator/payor must notify BLM of its determinations under this paragraph and paragraph (A) of this § 3103 1-(f)(5)(iv). The new royalty rate will not become effective until the first day of the second month after BLM receives notification, and will remain effective for 12 calendar months. 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.

(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 (f).

(vi) Certification. The operator/payor must use the applicable royalty rate when submitting the required royalty [\*18084] reports/payments to the

Minerals Management Service (MMS). In submitting royalty reports, payments using a royalty rate reduction authorized by this paragraph (f), the operator/payor 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 (f).

(vii) Agency action. If an operator/payor incorrectly calculates the royalty rate, the BLM will determine the correct rate and notify the operator/payor in writing. Any additional royalties due are payable immediately upon receipt of this notice. The BLM will assess late payment or underpayment charges 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 BLM will assess late payment or underpayment charges in accordance with 30 CFR 218.102.

(6) The BLM may suspend or terminate all royalty reductions granted under this paragraph (f) upon 6 month's notice in the Federal Register when BLM determines that:

(i) The average oil price remains above \$ 24 per barrel over a period of 6 consecutive months (based on the West Texas Intermediate 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, 1997, the royalty rate reductions authorized by this paragraph (f) 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 that can be attributed to this rule.

*OK since you're not  
encouraging large new  
capital expenditures  
otherwise you'd be  
hoarding money.*

(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) for oil completions using the lease royalty rate.

(11) The minimum royalty provisions of § 3103.3-2 will continue to apply.

\* \* \* \* \*

Dated April 4, 1995

Bob Armstrong,

Assistant Secretary of the Interior

[FR Doc 95-8702 Filed 4-7-95, 8:45 am]

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FEDERAL REGISTER  
Vol 60, No 61

Proposed Rules

DEPARTMENT OF THE INTERIOR (DOI)  
Bureau of Land Management (BLM)

43 CFR Part 3100

[WO-610-00-4110-2411]  
RIN 1004-AC26

Promotion of Development, Reduction of Royalty on Heavy Oil

60 FR 16424

DATE Thursday, March 30, 1995

ACTION Proposed rule

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To view the next page, type np\* TRANSMIT.

To view a specific page, transmit p\* and the page number, e.g. p\*1  
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**SUMMARY** The Bureau of Land Management (BLM) is issuing this proposed rule to amend the regulations relating to the waiver, suspension, or reduction of rental, royalty, or minimum royalty. This amendment would establish 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. This action is being taken to 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. The BLM believes that this amendment will result in substantial additional revenue for the States and Federal Government, increase the cumulative amount of domestic oil production from existing wells, increase the percentage of oil recovery from presently developed reservoirs, minimize the necessity of drilling new wells with their additional environmental impacts, assist in reducing the national balance of trade deficit, and help promote stability in the jobs and

services related to the domestic oil industry

**DATES** Comments should be submitted by May 30, 1995. Comments postmarked after this date may not be considered as part of the decisionmaking process in issuance of a final rule.

**ADDRESSES** Comments should be sent to Director (140), Bureau of Land Management, Room 5555, Main Interior Building, 1849 C Street, N.W., Washington, D.C. 20240. Comments will be available for public review in Room 5555 at the above address during regular business hours (7:45 a.m. to 4:15 p.m.), Monday through Friday.

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FOR FURTHER INFORMATION CONTACT: Dr. John W. Behout, Bureau of Land Management,  
(202) 452-0340 [ \*16425 ]

**SUPPLEMENTARY INFORMATION** 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. In order to encourage the greatest ultimate recovery of oil or gas and in the interest of conservation, the Secretary, upon a determination that it is necessary to promote development, or that a lease cannot be successfully operated under the terms provided therein, may reduce the royalty on an entire leasehold or any portion thereof. The provision concerning stripper well properties allows royalty reduction for properties that produce an average of less than 15 barrels of oil per eligible well per well-day.

The Bureau of Land Management (BLM) has reason to believe that additional royalty relief for producers of heavy crude oil may be necessary to maintain current levels of development, promote investment in enhanced recovery efforts, and encourage maximum recovery of the resource, thus warranting royalty reduction under Section 39 of the Mineral Leasing Act (30 U.S.C. 209).

Fluctuating oil prices, combined with high production costs, have resulted in an uncertain economic future for producers of low gravity crude oil. As recently as last January, California producers of heavy crude were spending between \$ 9 and \$ 10 to produce a barrel of crude oil that was typically selling for between \$ 8.50 and \$ 9 per barrel (from data provided by the Conservation Commission of California Oil and Gas Producers). When depreciation, depletion, and amortization costs were considered, nearly 60% of the state's production was uneconomic and more than 13,000 industry and industry-related jobs were at risk (California Independent Petroleum Association).

Heavy crude oil prices have recently risen to the point that the immediate crisis in California has passed. Many of the heavy oil properties remain only marginally economic, however, and are vulnerable to future down-turns in oil prices. As many as two-thirds of the marginal properties could be lost during a period of sustained low oil prices (National Petroleum Council Committee on Marginal Wells Executive Summary-Draft). The danger in losing these wells is that, although production from individual wells may be small, their collective loss would be significant. The United States would lose the opportunity to take advantage of new technologies being developed by the Department of Energy (DOE) and industry, and the remaining recoverable reserves would be lost.

This proposed rule would preserve the contribution of marginal producers of heavy crude oil to the national reserve base. As a result of this relief, more wells should stay on line (even in periods of depressed oil prices), fewer recoverable reserves should be lost, and there will be less adverse economic impact on States and local communities.

The DOE has modeled the BLM's proposed royalty rate reduction for heavy crude oil. It is DOE's conclusion that the proposal will benefit all producers of heavy oil while remaining revenue neutral to all oil producing States except California (California contains the majority of the nation's heavy oil reserves). Assuming a West Texas Intermediate Crude oil price of \$ 20 per barrel—a price consistent with recent oil markets—the proposal can be expected to increase recoverable reserves in California by around 72 percent, from 132.8 million barrels to 228.5 million barrels. The increase in recoverable reserves

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will ultimately result in a 35 percent increase in Federal revenues (royalties and individual and corporate taxes) and a 49 percent increase in California State revenues

A provision of the proposed rule provides for the termination of individual royalty reductions should the average price of West Texas Intermediate Crude oil rise to a level greater than \$ 28 per barrel for a period of at least 6 consecutive months. This provision is intended to ensure that royalty relief is only provided during periods of low market prices.

The proposed 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 measured 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. The royalty rate for years subsequent to the initial 12 month period will be the lesser of the newly calculated royalty rate or the royalty rate determined for the initial year. This provision is necessary to avoid discouraging additional investment in enhanced recovery and workovers that may have the collateral effect of increasing the gravity of the oil produced from the property. In no case, however, would the royalty rate exceed the rate established by the terms of the lease.

The section amended by this proposed rule also provides for royalty rate reductions for stripper oil wells. Many provisions of this proposed rule are essentially the same as the provisions of the existing regulations that pertain to stripper wells, except that references to "stripper well" have been replaced with "heavy oil well." The similarity between the existing provisions pertaining to stripper wells and the provisions of this proposed rule could allow for some restructuring of section 43 CFR 3103.4-1 to reduce the overall regulatory text and to increase clarity. The public is invited to comment on whether

reorganizing 43 CFR 31.34-1 should be considered in preparing the final heavy oil royalty reduction rule.

The principal author of this proposed rule is Dr. John W. Bebout, Senior Technical Specialist, Division of Fluid Minerals, assisted by the staff of the Division of Legislation and Regulatory Management, Bureau of Land Management.

It is hereby determined that this rule does not constitute 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.

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This rule has been reviewed under Executive Order 12860

The BLM has determined that this rule will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 et seq.). This is because the proposed royalty rate reduction is voluntary, requires no additional paperwork, and applies to all operators regardless of size. Additionally, the BLM has determined, under Executive Order 12630, that the rulemaking will not cause a taking of private property. [\*16426]

The BLM has certified that these regulations meet the applicable standards provided in sections 2(a) and 2(b)(2) 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 1010-0090 and 1004-0145

#### 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 proposed to be amended as set forth below

#### 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. 351-359

#### Subpart 3103--Fees, Rentals and Royalty

2. Section 3103.4-1 is amended by revising paragraph (b)(1), redesignating paragraph (e) as paragraph (g), and adding new paragraphs (e) and (f) to read as follows:

§ 3103.4-1 -- Waiver, suspension, or reduction of rental, royalty or minimum royalty

.....

(b)(1) An application for the above benefits on other than stripper oil well leases or heavy oil properties must be filed by the operator payor in the proper BLM office. It 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.

.....

(e)(1) A heavy oil well property is any Federal lease or portion thereof segregated for royalty purposes, a communitization area, or a unit.

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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) scale

(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 60 MCF of gas per day

(f) 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 payor 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 communitization agreement number or the unit agreement name), the names of the operators for each lease, the calculated new royalty rate as determined under paragraph (f)(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 1994, the operator must submit Purchaser's Statements for July, August, and September of 1994.

(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 1994, the operator must submit Purchaser's Statements for the months of September 1993, and March and September 1994, 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/ payor for calculating the weighted average API gravity for a heavy oil well property

$$\frac{(V[1] \times G[1]) + (V[2] \times G[2]) + (V[n] \times G[n])}{V[1] + V[2] + \dots + V[n]} = \text{Weighted Average API gravity for a property}$$

Where

V[1]=Average Production (bbls) of Well #1 over the last 3 calendar months of sales

V[2]=Average Production (bbls) of Well #2 over the last 3 calendar months of

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sales

V[n]= Average Production (bbls) of each additional well (V[3], V[4], etc ) over the last 3 calendar months of sales

G[1]= Average Gravity (degrees) of oil produced from Well #1 over the last 3 calendar months of sales

G[2]= 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 (G[3], G[4], 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 degrees API, Well #2, 6,000 bbls, 21 degrees API, Well #3, 2,000 bbls, 14 degrees 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 communitization agreement or a unit participating area, the weighted average API oil gravity for the lands dedicated to that specific communitization agreement or unit participating area must be determined in the manner prescribed in paragraph (f)(3) of this section and assigned to all property [\*16-27] subject to Federal royalties in the communitization agreement or unit participating area

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

(i) Qualifying royalty rate determination

(A) The operator/payor 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 oil less than 3 times in their productive life may still qualify for this royalty rate reduction. However, no further reductions will be granted until the property has a sales history of at

least 3 production months (see paragraph (f)(5)(iii) of this section)

(ii) Calculating the qualifying royalty rate. If the Federal leases or portions thereof (e.g., communitization or unit agreements) qualify as heavy oil property, the operator-payer must use the weighted average API gravity rounded down to the nearest 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 Royalty
--

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average API gravity (degrees)	rate (percent)
6	0.5
7	1.4
8	2.2
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	9.9
18	10.8
19	11.6
20	12.5

(iii) **New royalty rate effective date.** The new royalty rate will be effective on the first day of production 2 months after BLM receives notification by the operator/payor. The rate will apply to all oil production from the property for the next 12 months. If the API oil gravity is 20 degrees or greater, the royalty rate will be the rate in the lease terms.

(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/payor must determine the weighted average API oil gravity for the property for that period. The operator/payor must then determine the royalty rate for the following year using the table in paragraph (f)(5)(ii) of this section.

(B) The operator/payor must compare the newly determined royalty rate to the initial qualifying royalty rate. The operator/payor must notify BLM of its determinations under this paragraph and paragraph (A) of this § 3103.1-4(f)(5)(iv). The lower of the two rates will be used for the new 12-month period. The new royalty rate will not become effective until the first day of the second month after BLM receives notification, and will remain effective for 12 calendar months. 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 remain at the previous royalty rate until the next 12-month anniversary

(C) The royalty rate will never exceed the heavy oil property royalty rate calculated during the first qualifying period unless and until BLM terminates all heavy oil royalty rate reductions under paragraph (f)(6) (i) or (ii) of this section

(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 (f)

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(vi) **Certification** The operator/payor 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 (f), the operator/payor 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 (f).

(vii) **Agency action** If an operator/payor incorrectly calculates the royalty rate, the BLM will determine the correct rate and notify the operator/payor in writing. Any additional royalties due are payable immediately upon receipt of this notice. The BLM will assess late payment or underpayment charges 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/payor. 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/payor must pay the difference in royalty resulting from the retroactive application of the non-manipulated rate. The BLM will assess late payment or underpayment charges in accordance with 30 CFR 218.102.

(6) The BLM may suspend or terminate all royalty reductions granted under this paragraph (f) upon 6 month's notice in the Federal Register when BLM determines that-

(i) The average oil price remains above \$ 28 per barrel over a period of 6 consecutive months (based on the West Texas Intermediate 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, 1997, the royalty rate reductions authorized by this paragraph (f) have not been effective in reducing the loss of otherwise recoverable reserves resulting from wells being shut in or abandoned.

(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 pavor must separately calculate the royalty for gas production (including condensate produced in association with gas) for oil completions using the lease royalty rate

(11) The minimum royalty provisions of @ 3103 3-2 will continue to apply

\* \* \* \* \*

the effective date of this regulation, of a petition to reinstate a lease under §3108.2-3 of this title; and

(f) Each succeeding time a specific lease is reinstated under §3108.2-3 of this title, the annual rental on that lease shall increase by an additional \$5 per acre or fraction thereof for leases that were originally issued non-competitively and by an additional \$10 per acre or fraction thereof for leases that were originally issued competitively.

[53 FR 17353, May 16, 1988 and 53 FR 22837, June 17, 1988]

### §3103.3 Royalties.

#### §3103.3-1 Royalty on production.

(a) Royalty on production shall be payable only on the mineral interest owned by the United States. Royalty shall be paid in amount or value of the production removed or sold as follows:

(1) 12½ percent on all leases, including exchange and renewal leases and leases issued in lieu of unpatented oil placer mining claims under §3108.2-4 of this title, issued after December 22, 1987, except:

(i) Leases issued after December 22, 1987, resulting from offers to lease or bids filed on or before December 22, 1987, which are subject to the rates in effect on December 22, 1987; and

(ii) Leases issued on or before December 22, 1987, which are subject to the rates contained in the lease or in regulations at the time of issuance;

(2) 16½ percent on noncompetitive leases reinstated under §3108.2-3 of this title plus an additional 2 percentage-point increase added for each succeeding reinstatement;

(3) Not less than 4 percentage points above the rate used for royalty determination contained in the lease that is reinstated or in force at the time of issuance of the lease that is reinstated for competitive leases, plus an additional 2 percentage-point increase added for each succeeding reinstatement.

(b) Leases that qualify under specific provisions of the Act of August 8, 1946 (30 U.S.C. 226c) may apply for a limitation of a 12½ percent royalty rate.

(c) The average production per well per day for oil and gas shall be determined pursuant to 43 CFR 3162.7-4.

(d) Payment of a royalty on the helium component of gas shall not convey the right to extract the helium. Applications for the right to extract helium shall be made under part 16 of this title.

[53 FR 22838, June 17, 1988]

#### §3103.3-2 Minimum royalties.

(a) A minimum royalty shall be payable at the expiration of each lease year beginning on or after a discovery of oil or gas in paying quantities on the lands leased, except that on unitized leases the minimum royalty shall be payable only on the participating acreage, at the following rates:

(1) On leases issued on or after August 8, 1946, and on those issued prior thereto if the lessee files an election under section 15 of the Act of August 8, 1946, a minimum royalty of \$1 per acre or fraction thereof in lieu of rental, except as provided in paragraph (a)(2) of this section; and

(2) On leases issued from offers filed after December 22, 1987, and on competitive leases issued from successful bids placed at oral auctions conducted after December 22, 1987, a minimum royalty in lieu of rental of not less than the amount of rental which otherwise would be required for that lease year.

(b) Minimum royalties shall not be prorated for any lands in which the United States owns a fractional interest but shall be payable on the full acreage of the lease.

(c) Minimum royalties and rentals on non-participating acreage shall be payable to the Service.

(d) The minimum royalty provisions of this section shall be applicable to leases reinstated under §3108.2-3 of this title and leases issued under §3108.2-4 of this title.

[46 FR 33882, July 22, 1983, as amended at 46 FR 11837, Mar. 27, 1984; 46 FR 30448, July 30, 1984; 53 FR 22838, June 17, 1988]

#### §3103.4 Promotion of development.

##### §3103.4-1 Waiver, suspension or reduction of rental, royalty or minimum royalty.

(a) In order to encourage the greatest ultimate recovery of oil or gas and in the interest of conservation, the Secretary, upon a determination that it is necessary to promote development or that the leases cannot be successfully operated under the terms provided therein, may waive, suspend or reduce the rental or minimum royalty or reduce the royalty on an entire leasehold, or any portion thereof.

(b)(1) An application for the above benefits on other than stripper oil well properties shall be filed in the proper BLM office. It shall contain the serial numbers 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.

(2) Each application shall show the number, location and status of each well drilled, a tabulated statement for each month covering a period of not less than 6 months prior to the date of filing the application of the aggregate amount of oil or gas subject to royalty, the number of wells counted as producing each month and the average production per well per day.

(3) Every application shall contain a detailed statement of expenses and costs of operating the entire lease, the income from the sale of any production and all facts tending to show whether the wells can be successfully operated upon the fixed royalty or rental. Where the application is for a reduction in royalty, full information shall be furnished as to whether overriding royalties, payments out of production, or similar interests are paid to others than the United States, the amounts so paid and efforts made to reduce them. The applicant shall also file agreements of the holders to a reduction of all other royalties or similar payments from the leasehold to an aggregate not in excess of one-half the royalties due the United States.

(c)(1) A stripper well property is any Federal lease or portion thereof segregated for royalty purposes, a

communization agreement, or a participating area of a unit agreement, operated by the same operator, that produces an average of less than 15 barrels of oil per eligible well per well-day for the qualifying period.

(2) An eligible well is an oil well that produces or an injection well that injects and is integral to production for any period of time during the qualifying or subsequent 12-month period.

(3) 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 liquid hydrocarbons) or any completion producing oil and less than 60 MCF of gas per day.

(4) An injection well is a well that injects a fluid for secondary or enhanced oil recovery, including reservoir pressure maintenance operations.

(d) Stripper oil well property royalty rate reduction shall be administered according to the following requirements and procedures.

(1) An application for the benefits under paragraph (a) of this section for stripper oil well properties is not required.

(2) Total oil production (regardless of disposition) for the subject period from the eligible wells on the property is totaled and then divided by the total number of well days or portions of days, both producing and injection days, as reported on Form MMS-3160 or MMS-4054 for the eligible wells to determine the property average daily production rate. For those properties in communization agreements and participating areas of unit agreements that have allocated (not actual) production, the production rate for all eligible well(s) in that specific communization agreement or participating area is determined and shall be assigned to that allocated property in that communization agreement or participating area.

(3) Procedures to be used by operator:

(1) Qualifying determination.  
(A) Calculate an average daily production rate for the property in order to verify that the property qualifies as a stripper property.

(B) The initial qualifying period for producing properties is the period August 1, 1990, through July 31, 1991. For

the properties that were shut-in for 12 consecutive months or longer, the qualifying period is the 12-month production period immediately prior to the shut-in. If the property does not qualify during the initial qualifying period, it may later qualify due to production decline. In those cases, the 12-month qualifying period will be the first consecutive 12-month period beginning after August 31, 1990, during which the property qualifies.

(ii) Qualifying royalty rate calculation. If the property qualifies, use the production rate rounded down to the next whole number (e.g., 6.7 becomes 6) for the qualifying period, and apply the following formula to determine the maximum royalty rate for oil production from the Federal leases for the life of the program.

Royalty Rate (%) =  $0.5 + (0.8 \times \text{the average daily production rate})$

The formula-calculated royalty rate shall apply to all oil production (except condensate) from the property for the first 12 months. The rate shall be effective the first day of the production month after the Minerals Management Service (MMS) receives notification. If the production rate is 15 barrels or greater, the royalty rate will be the rate in the lease terms.

(iii) Outyears royalty rate calculations.

(A) At the end of each 12-month period, the property average daily production rate shall be determined for that period. A royalty rate shall then be calculated using the formula in paragraph (d)(3)(ii) of this section.

(B) The new calculated royalty rate shall be compared to the qualifying period royalty rate. The lower of the two rates shall be used for the current period provided that the operator notifies the MMS of the new royalty rate. The new royalty rate shall not become effective until the first day of the month after the MMS receives notification. Notification shall be received on Form MMS-4377 and mailed to Minerals Management Service, P.O. Box 17110, Denver, CO 80217. If the operator does not notify the MMS of the new royalty rate within 60 days after the end of the subject 12-month period, the royalty rate for the property shall revert back to

the royalty rate established as the qualifying period royalty rate, effective at the beginning of the current 12-month period.

(C) The royalty rate shall never exceed the calculated qualifying royalty rate for the life of this program.

(iv) Prohibition. For the qualifying period and any subsequent 12-month period, the production rate shall be the result of routine operational and economic factors for that period and for that property and not the result of production manipulation for the purpose of obtaining a lower royalty rate. A production rate that is determined to have resulted from production manipulation will not receive the benefit of a royalty rate reduction.

(v) Certification. The applicable royalty rate shall be used by the operator/payer when submitting the required royalty reports/payments to MMS. By submitting royalty reports/payments using the royalty rate reduction benefits of this program, the operator certifies that the production rate for the qualifying and subsequent 12-month period was not subject to manipulation for the purpose of obtaining the benefit of a royalty rate reduction, and the royalty rate was calculated in accordance with the instructions and procedures in these regulations.

(vi) Agency action. If a royalty rate is improperly calculated, the MMS will calculate the correct rate and inform the operator/payers. Any additional royalties due are payable immediately upon notification. Late payment or underpayment charges will be assessed in accordance with 30 CFR 218.102. The BLM may terminate a royalty rate reduction if it is determined that the production rate was manipulated by the operator for the purpose of receiving a royalty rate reduction. Terminations of royalty rate reductions will be effective on the effective date of the royalty rate reduction resulting from the manipulated production rate (i.e., the termination will be retroactive to the effective date of the improper reduction). The operator/payer shall pay the difference in royalty resulting from the retroactive application of the unmanipulated rate. Late payment or underpayment charges will be assessed in accordance with 30 CFR 218.102.

(4) The royalty rate reduction provision for stripper well properties shall be effective as of October 1, 1992. If the oil price, adjusted for inflation by BLM and MMS, using the implicit price deflator for gross national product with 1991 as the base year, remains on average above \$28 per barrel, based on West Texas Intermediate crude average posted price for a period of 6 consecutive months, the benefits of the royalty rate reduction under this section may be terminated upon 6 months' notice, published in the FEDERAL REGISTER.

(5) The Secretary will evaluate the effectiveness of the stripper well royalty reduction program and may at any time after September 10, 1997, termi-

nate any or all royalty reductions granted under this section upon 6 months notice.

(6) The stripper well property royalty rate reduction benefits shall apply to all oil produced from the property.

(7) The royalty for gas production (including liquids produced in association with gas) for oil completions shall be calculated separately using the lease royalty rate.

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

(9) The minimum royalty provisions of §3103.3-2 apply.

(10) Examples.

## § 1.43-3 Certification.

- (a) Petroleum engineer's certification of a project.
- (1) In general.
  - (2) Timing of certification.
  - (3) Content of certification.
- (b) Operator's continued certification of a project.
- (1) In general.
  - (2) Timing of certification.
  - (3) Content of certification.
- (c) Notice of project termination.
- (1) In general.
  - (2) Timing of notice.
  - (3) Content of notice.
- (d) Failure to submit certification.
- (e) Effective date.

## § 1.43-4 Qualified enhanced oil recovery costs.

- (a) Qualifying costs.
- (1) In general.
  - (2) Costs paid or incurred for an asset which is used to implement more than one qualified enhanced oil recovery project or for other activities.
- (b) Costs defined.
- (1) Qualified tertiary injectant expenses.
  - (2) Intangible drilling and development costs.
  - (3) Tangible property costs.
  - (4) Examples.
- (c) Primary purpose.
- (1) In general.
  - (2) Tertiary injectant costs.
  - (3) Intangible drilling and development costs.
  - (4) Tangible property costs.
  - (5) Offshore drilling platforms.
  - (6) Examples.
- (d) Costs paid or incurred prior to first injection.
- (1) In general.
  - (2) First injection after filing of return for taxable year costs are allowable.
  - (3) First injection more than 36 months after close of taxable year costs are paid or incurred.
  - (4) Injections in volumes less than the volumes specified in the project plan.
  - (5) Examples.
- (e) Other rules.
- (1) Anti-abuse rule.
  - (2) Costs paid or incurred to acquire a project.
  - (3) Examples.

## § 1.43-5 At-risk limitation. (Reserved)

## § 1.43-6 Election out of section 43.

- (a) Election to have the credit not apply.
- (1) In general.
  - (2) Time for making the election.
  - (3) Manner of making the election.
- (b) Election by partnerships and S corporations.

## § 1.43-7 Effective date of regulations.

(T.D. 8448, 57 FR 54923, Nov. 23, 1992)

## § 1.43-1 The enhanced oil recovery credit—general rules.

(a) *Claiming the credit*—(1) *In general*. The enhanced oil recovery credit (the "credit") is a component of the section 38 general business credit. A taxpayer that owns an operating mineral interest (as defined in § 1.614-2(b)) in a property may claim the credit for qualified enhanced oil recovery costs (as described in § 1.43-4) paid or incurred by the taxpayer in connection with qualified enhanced oil recovery projects (as described in § 1.43-2) undertaken with respect to the property. A taxpayer that does not own an operating mineral interest in a property may claim the credit. To the extent a credit included in the current year business credit under section 38(b) is unused under section 38, the credit is carried back or forward under the section 38 business credit carryback and carryforward rules.

(2) *Examples*. The following examples illustrate the principles of this paragraph (a).

*Example 1. Credit for operating mineral interest owner.* In 1992, A, the owner of an operating mineral interest in a property, begins a qualified enhanced oil recovery project using cyclic steam. B, who owns no interest in the property, purchases and places in service a steam generator. B sells A steam, which B uses as a tertiary injectant described in section 193. Because A owns an operating mineral interest in the property with respect to which the project is undertaken, A may claim a credit for the cost of the steam. Although B owns the steam generator used to produce steam for the project, B may not claim a credit for B's costs because B does not own an operating mineral interest in the property.

*Example 2. Credit for operating mineral interest owner.* C and D are partners in CD, a partnership that owns an operating mineral interest in a property. In 1992, CD begins a qualified enhanced oil recovery project using cyclic steam. D purchases a steam generator and sells steam to CD. Because CD owns an operating mineral interest in the property with respect to which the project is undertaken, CD may claim a credit for the cost of the steam. Although D owns the steam generator used to produce steam for the project, D may not claim a credit for the costs of the steam generator because D paid those costs

## Internal Revenue Service, Treasury

in a capacity other than that of an operating mineral interest owner.

(b) *Amount of the credit*. A taxpayer's credit is an amount equal to 15 percent of the taxpayer's qualified enhanced oil recovery costs for the taxable year, reduced by the phase-out amount, if any, determined under paragraph (c) of this section.

(c) *Phase-out of the credit as crude oil prices increase*—(1) *In general*. The amount of the credit (determined without regard to this paragraph (c)) for any taxable year is reduced by an amount which bears the same ratio to the amount of the credit (determined without regard to this paragraph (c))

as—

- (i) The amount by which the reference price determined under section 2634(c) for the calendar year immediately preceding the calendar year in which the taxable year begins exceeds \$28 (as adjusted under paragraph (c)(2) of this section); bears to
- (ii) \$6.

(2) *Inflation adjustment*—(i) *In general*. For any taxable year beginning in a calendar year after 1991, an amount equal to \$28 multiplied by the inflation adjustment factor is substituted for the \$28 amount under paragraph (c)(1)(i) of this section.

(ii) *Inflation adjustment factor*. For purposes of this paragraph (c), the inflation adjustment factor for any calendar year is a fraction, the numerator of which is the GNP implicit price deflator for the preceding calendar year and the denominator of which is the GNP implicit price deflator for 1990. The "GNP implicit price deflator" is the first revision of the implicit price deflator for the gross national product as computed and published by the Secretary of Commerce. As early as practicable, the inflation adjustment factor for each calendar year will be published by the Internal Revenue Service in the Internal Revenue Bulletin.

(3) *Examples*. The following examples illustrate the principles of this paragraph (c).

*Example 1. Reference price exceeds \$28*. In 1992, E, the owner of an operating mineral interest in a property, incurs \$100 of qualified enhanced oil recovery costs. The reference price for 1991 determined under section

2634(c) is \$30 and the inflation adjustment factor for 1992 is 1. E's credit for 1992 determined without regard to the phase-out for crude oil price increases is \$15 (\$100 × 15%). In determining E's credit, the credit is reduced by \$5 (\$15 × (\$30 - \$28) ÷ (\$30 - \$25)). Accordingly, E's credit for 1992 is \$10 (\$15 - \$5).

*Example 2. Inflation adjustment*. In 1993, F, the owner of an operating mineral interest in a property, incurs \$100 of qualified enhanced oil recovery costs. The 1992 reference price is \$34, and the 1993 inflation adjustment factor is 1.10. F's credit for 1993 determined without regard to the phase-out for crude oil price increases is \$15 (\$100 × 15%). In determining F's credit, \$30.80 (1.10 × \$28) is substituted for \$28, and the credit is reduced by \$6 (\$15 × (\$34 - \$30.80) ÷ (\$34 - \$30)). Accordingly, F's credit for 1993 is \$9 (\$15 - \$6).

(d) *Reduction of associated deductions*—(1) *In general*. Any deduction allowable under chapter I for an expenditure taken into account in computing the amount of the credit determined under paragraph (b) of this section is reduced by the amount of the credit attributable to the expenditure.

(2) *Certain deductions by an integrated oil company*. For purposes of determining the intangible drilling and development costs that an integrated oil company must capitalize under section 29(b), the amount allowable as a deduction under section 263(c) is the deduction allowable after paragraph (d)(1) of this section is applied. See § 1.43-1(b)(2) (extent to which integrated oil company intangible drilling and development costs are qualified enhanced oil recovery costs).

(e) *Basis adjustment*. For purposes of subtitle A, the increase in the basis of property which would (but for this paragraph (e)) result from an expenditure with respect to the property is reduced by the amount of the credit determined under paragraph (b) of this section attributable to the expenditure.

(f) *Passthrough entity basis adjustment*—(1) *Partners' interests in a partnership*. To the extent a partnership expenditure is not deductible under paragraph (d)(1) of this section or does not increase the basis of property under paragraph (e) of this section, the expenditure is treated as an expenditure described in section 706(a)(2)(B) (concerning decreases to basis of partnership interests). Thus, the adjusted bases of the partners' interests in the

TONY KNOWLES, GOVERNOR

**DEPARTMENT OF NATURAL RESOURCES**

DIVISION OF OIL AND GAS

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PHONE. (907) 269-3784

February 9, 1996

Mr. John Morgan  
BP Exploration (Alaska) Inc.  
900 East Benson Boulevard  
P.O. Box 196612  
Anchorage, Alaska 99519-6612

Mr. Edward K. Behm  
OXY USA Inc.  
6 Desta Drive, Suite 6000  
P.O. Box 50250  
Midland, Texas 79710-0250

Dear Sirs:

BP Exploration (Alaska) Inc. ("BP") and OXY USA Inc. ("OXY") have made representations to the House of Representatives in support of HB 325 concerning the feasibility of heavy oil development in the Milne Point Unit, Schrader Bluff Participating Area in both a "white paper" dated January 22, 1996, and in testimony to the House Subcommittee on Oil and Gas, the House Resources Committee and the House Finance Committee. Further, BP and OXY offered to make detailed back-up data available to the Division of Oil and Gas. As a result, the Division has been asked by members of the Alaska State Legislature to review the economics of heavy oil development at the Milne Point Unit in order to evaluate the provisions of HB 325. On February 8, 1996, the Division received from OXY a summary sheet titled "Critical Assumptions." More information is needed to provide background to the bottomline figures presented so far, similar to the information OXY previously provided for its prior Milne Point Unit royalty reduction request and the information BP provided to assist the Division in evaluating BP's economics for another field.

In order to perform the requested review, the Division will need detailed and comprehensive data from BP and OXY supporting the analyses that both companies have previously presented. This data must cover both the full Schrader Bluff pool development and, because the proposed legislation is currently structured on a per-well basis, the per-well economics of the Schrader Bluff pool. In both cases, the companies should provide the incremental company economics that are projected to accrue to the project through facility sharing arrangements, pipeline tariffs, tax benefits, etc. We recognize that each company's economic assessment is different, and so each company should provide its own analysis of these impacts.

Mr. John Morgan  
BP Exploration (Alaska) Inc.  
February 9, 1996

Mr. Edward J. Behm  
OXY USA Inc.

Per-well economics. The "Critical Assumptions" sheet provides a summary guide to the kind and detail of information required by the Division. Supporting data necessary includes:

1. Production and Revenues: the historical data for each Schrader Bluff well, including initial production rates, decline rates and per-well reserves, plus all back-up data supporting the chart presented in BP's Finance Committee presentation on February 8, 1996 ("BP's Presentation") entitled "Schrader Bluff Typical Well Production Rate vs Time (years)."
2. Drilling and equipment costs: historical data for each Schrader Bluff well, plus an analysis of the cost reduction trends including any documents supporting the statement made in BP's Presentation that the 1995 Schrader Bluff development program has demonstrated that drilling costs have been reduced, that completion costs have remained constant, and that ESP life has been improved. Provide the results of the well performance and technical study referred to in BP's Presentation as soon as it is available.
3. Supporting data for the dry hole cost assumption of 86.80% of producing well costs and for the 90% success rate assumption.
4. Back-up data and analysis for the \$0.72/bbl associated facility cost, including an explanation of the calculation used. This component should be also thoroughly documented in the Schrader Bluff development economics.
5. Complete detail and analysis for the \$2.20/bbl operating expense estimate and a detailed explanation of the \$0.50/bbl for fixed per-well operating expense. The operating expenses should also be thoroughly documented in the Schrader Bluff pool development economics. Forecasts of both this component and item 4 above must be supported by historical (actual) data.
6. Complete detail and analysis for OXY's calculation of 0.6% severance tax and 8.0% property tax percentages calculated on revenue, including an explanation of why revenue was used instead of the oil value and property assessment. If BP has different values, please provide those values plus the supporting detail.

Schrader Bluff pool development. It is the Division's understanding that the decision to develop the Schrader Bluff is not made on a well-by-well basis. For example, Mr. Policky testified that development of the Schrader Bluff pool would require upgrading of the central production facility serving all horizons in the unit. BP and OXY should each provide the Division with the complete analysis of the whole project, including any documentation describing the "full development scenario" of 350-400 wells presented in OXY's Critical Assumption sheet versus any documentation describing the 230 well

Mr. John Morgan  
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February 9, 1996

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development scenario represented in the BP's Presentation in a chart titled "Additional Production from Heavy Oil by Development Year." Included in this information should be the same kind of analysis that would be presented to corporate decisionmakers who would ultimately commit resources to the development of the Schrader Bluff pool. Additionally, please provide the economic analysis of facility expansion and the way that such capital expenditures are to be allocated to Schrader Bluff production. Potential areas of risk should be identified and an explanation of how they were incorporated into the assessment.

Other Information Needed.

1. Any BP documents prepared for the purpose of seeking financial approval and commitment to acquire its interest in the Milne Point Unit including any *pro forma* finance memoranda.
2. Copies of all AFEs (both accepted and rejected) for any capital expenditures relating to the Schrader Bluff pool including the \$15MM expenditures for the recent 6 new wells, well completions, and additional technical study.
3. Internal documents that explain the company's approval and sanction process for a major investment, including economic hurdle parameters, IRR, NPV, PW, any other financial criteria required by the company's evaluation, corporate, federal and state income tax rates, cost of capital, and Schrader Bluff contribution to company incremental economics. NOTE: BP has already provided all but the Schrader Bluff contribution to company incremental economics and need not duplicate information provided.
4. From OXY, an EXCEL-type spreadsheet (on disk to speed analysis) detailing how the 12.8 and 15.9 rates of return, the 6.5 and 5.4 year pay back periods, the \$115M net discounted cash flow, negative \$307M discounted cash flows, and the total per-well royalties undiscounted of \$1843M and \$1,040M were calculated in the white paper. Please provide a calculation of the total per-well royalties using the fifteen percent discount rate that OXY used for its own internal analysis.  
From BP, all documents supporting Mr. Policky's testimony to the House Finance Committee that BP's rate of return varies 2-3% higher than OXY's rate of return, and an EXCEL-type spreadsheet (on disk to speed analysis) of the calculation of the rate of return.
5. BP's 1995-1997 Business Plan dated 9/30/94 and any other BP or OXY Business Plan related to Schrader Bluff pool development.
6. Provide BP and OXY's actual marine transportation cost per barrel and a description of the differences between BP and OXY's transportation costs.

Mr. John Morgan  
BP Exploration (Alaska) Inc.  
February 9, 1996

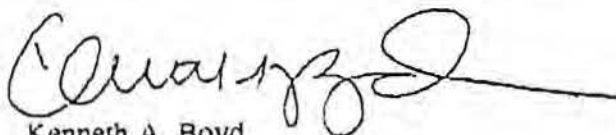
Mr. Edward J. Behm  
OXY USA Inc.

7. The Arthur D. Little study cited in the BP/OXY white paper states that a TAPS owner has a \$1.00/bbl advantage over a non-TAPS owner. If either BP or OXY does not agree with that proposition please provide the relevant calculation along with the supporting documentation.

8. Mr. Policky testified on February 8, 1996, to the House Finance Committee that currently the Milne Point Unit CPF is running at capacity at 25MBD with Kuparuk production; that they intend to add 40MBD in the next few weeks for Kuparuk production; that they intend to add 10MBD capacity in 1997 for Cascade/Kuparuk production; and that they would then need to add an additional 15MBD capacity for Schrader Bluff production. Please provide a detailed schedule of production versus capacity for the MPU CPF specifically explaining the capacity schedule as it relates to the production curve for the 230 well development scenario that shows a peak of 45MBD. If not detailed above already, please provide a detailed capital investment schedule for the two Schrader Bluff pool development scenarios.

If you wish the Division to maintain any of the information submitted as confidential, please mark each page "confidential," submit such information in a sealed envelope separate from non-confidential information, and provide a statement describing the authority under which the Division may maintain the information confidential. If you have any questions about the analyses or data to be provided, please address them in writing to Kevin Banks, Petroleum Economist, Division of Oil and Gas, 3601 C Street, Suite 1380, Anchorage, Alaska, 99503-5948. Because we are dealing with the Legislature in a public forum, any communications should be made in writing.

Very truly yours,



Kenneth A. Boyd  
Director, Division of Oil and Gas

cc: Commissioner John Shively, Department of Natural Resources  
Representative Mark Hanley, Co-Chair, House Finance Committee,  
Alaska State Legislature  
Jim Palmer, BP Exploration (Alaska) Inc.

# HOUSE COMMITTEE REPORT

(7)

Date Referred: April 28, 1995

FURTHER REFERRALS:

Resources  
Finance

Date of Committee Action: 1/23/96

The HOUSE SPECIAL COMMITTEE ON OIL AND GAS Committee considered:

HB 325

HOUSE BILL NO. 325

ROYALTY SUSPENSION: N. SLOPE HEAVY OIL.

"An Act authorizing suspension of payment of a portion of the royalty due the state for initial production of heavy oil from wells on the Arctic Slope."

recommends it be replaced  
with the following committee substitute

CS HB 325 (04G)

the same title  
 a new title

additional referral to \_\_\_\_\_ Committee

attached amendment(s)

ADOPTS: \_\_\_\_\_ Letter of Intent

ATTACHES NEW FISCAL NOTE(S): (Dept)

APPROVES PREVIOUS: (Dept/Date)

fiscal note(s) ① DNR ② DOR

fiscal note(s) \_\_\_\_\_

zero fiscal note(s) \_\_\_\_\_

zero fiscal note(s) \_\_\_\_\_

SIGNING WITH RECOMMENDATIONS	DP	DNP	NR	AM
<i>John Degan</i>	✓			
<i>N. K. Kolesky</i>	✓			
<i>W. K. Williams</i>	X			
<i>Frank [unclear]</i>			✓	
<i>Robert [unclear]</i>	X			
<i>and [unclear]</i>		X		
<i>Bette Davis by Shirley [unclear]</i>	X			

CHAIR'S SIGNATURE

*N. K. Kolesky*

1-23-96

D  
(9)

HOUSE COMMITTEE REPORT

2/7/96

Date Referred to Committee: January 24, 1996

FURTHER REFERRALS:

Finance

Date of Committee Action: 2/7/96

The RESOURCES Committee considered:

HB 325

HOUSE BILL NO. 325

ROYALTY SUSPENSION: N. SLOPE HEAVY OIL

"An Act authorizing suspension of payment of a portion of the royalty due the state for initial production of heavy oil from wells on the Arctic Slope."

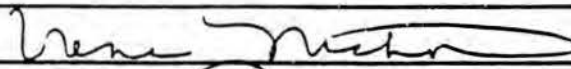

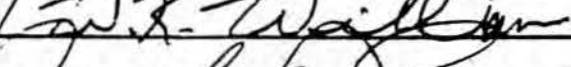
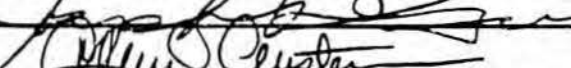

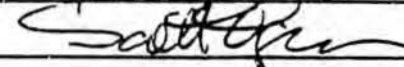
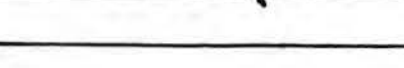
recommends it be replaced with the following committee substitute CSHB 325 (0+6) [ ] the same title [X] a new title

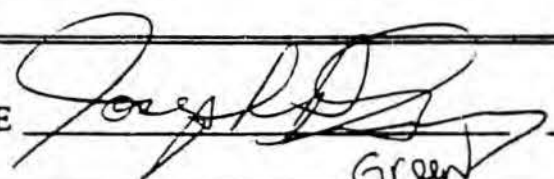
[ ] additional referral to \_\_\_\_\_ Committee  
[ ] attached amendment(s)

ADOPTS: \_\_\_\_\_ Letter of Intent

ATTACHES NEW FISCAL NOTE(S): (Dept) \_\_\_\_\_ APPROVES PREVIOUS: (Dept/Date) REV, DNR 1/24/96  
[ ] fiscal note(s) \_\_\_\_\_ (2) [X] fiscal note(s) \_\_\_\_\_

[ ] zero fiscal note(s) \_\_\_\_\_ [ ] zero fiscal note(s) \_\_\_\_\_

SIGNING WITH RECOMMENDATIONS	DP	DNP	NR	AM
 Nicholia				X
 DAVIES				X
 Williams	✓			
 Green	✓			
 Austerman	✓			
 Kott	✓			
 Ogan	✓			
	(5)			(2)

CO-CHAIR'S SIGNATURE  Green




**BP EXPLORATION**

**James A. Palmer**  
Director  
External Affairs  
Alaska

BP Exploration (Alaska) Inc  
900 East Benson Boulevard  
P O Box 196612  
Anchorage, Alaska 99519-6612  
(907) 564-5435

November 10, 1995

Representative Joseph Green  
Alaska State Legislature  
716 W. Fourth Avenue, Suite 350  
Anchorage, Alaska 99501-2133

Dear Representative ~~Green~~ 

Earlier this year, BP Exploration (Alaska) commissioned a study on the economic impacts of marginal oil field development in Alaska. Conducted by the Institute of Social and Economic Research, the results of the study were presented to the State of Alaska Oil and Gas Policy on June 5, 1995.

Although specific marginal fields would have differing degrees of economic and public sector impacts, the general conclusion about the significance of developing marginal oil fields is important to note.

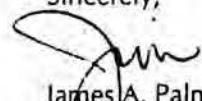
"Marginal oil field development in Alaska can generate jobs and income for Alaska workers, sales for Alaska businesses, and an increase in the state tax base more than sufficient to offset any additional costs to government from resource management and public service requirements from population increase."

Additionally, when compared to the state's natural resource revenues and management expenditures of fishing, lands, wildlife, mining and timber, the marginal oil field is the only case where resource management costs are covered by the revenues generated, and the substantial revenues are available to contribute to the general costs of the government (see Figure 5B in attached summary).

As you know, the oil industry faces a variety of competitive challenges it must overcome in order to attract the funds it needs to survive and grow in Alaska. Together with the state, we've begun to take our first tangible steps toward overcoming our competitive disadvantages by working together. This includes efforts such as last year's legislation that encourages development of new, economically marginal oil fields.

This study is another step in the cooperative process. I thought you would appreciate receiving a copy of the executive summary for your initial examination. If you would like a copy of the entire report, please feel free to give me a call at 564-5435.

Sincerely,



James A. Palmer  
Director, External Affairs  
Alaska

encl:

## MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

### EXECUTIVE SUMMARY

Marginal oil field development in Alaska can generate jobs and income for Alaska workers, sales for Alaska businesses, and an increase in the state tax base more than sufficient to offset any additional costs to government from resource management and public service requirements from population increase.

This conclusion is based on an analysis using existing information about the economy and public sector combined with a description of a hypothetical marginal oil field. In reality, each marginal field would have different characteristics, and the actual economic and public sector effects would differ from the description in this study. However, given the economics of field development, this study demonstrates that the general conclusions are consistent with a broad range of assumptions about both field characteristics and the economy.

The purpose of this study is to provide a framework for analysis of the economic effects of new, small marginal oil fields which may be typical of new petroleum industry activity in Alaska. The analysis is generic and hopefully will lead to more detailed and specific studies where appropriate. Some of the information used to develop the parameters for the analysis come from the ongoing study of the Badami oil field on the North Slope. Since that project is only in the earliest stages of its evolution, it would be inappropriate to interpret this analysis as a study of the Badami prospect.

The study examines a hypothetical marginal oil field on the North Slope with anticipated recoverable reserves of 100 million barrels of oil. We assume a total development budget of \$320 million, most of which would be spent in a two-year period during which the initial wells would be drilled, the pipeline constructed, the modules fabricated and put into place, and the operating facility built. Production would subsequently continue over a 20-year period at a cost of \$320 million. In the early production years, the drilling of wells would continue and after year 5, the drilling activity would switch to workovers of the existing wells. The purpose of these development and production cost figures is to calculate economic effects, and they should not be interpreted as reflecting the actual costs associated with any particular field.

Although some expenditures, in particular module fabrication and equipment for the modules and pipeline, would be purchased outside the state, much of the work would be carried out onsite during both field development and production. These tasks include site preparation, pipeline and module installation, and well drilling; and all have a large labor component. During production the operation of the field and drilling would continue around the clock so the number of workers employed would be 4

times the number of jobs to be done onsite. The development and production jobs would require highly trained and skilled workers so wages would be high and some specialized jobs would, of necessity, be filled by workers from Outside. Based on current experience, the share of jobs going to residents would be high, but some workers would choose to live outside the state.

Other costs associated with field development and production would generate sales, employment, and payrolls for Alaska vendors providing supplies, equipment, and services to the owner company, the oil service companies doing the contract drilling and other work, the construction contractors, etc. A large portion of the economic effect of marginal field development would come from the recirculation within the economy of the high payrolls paid the North Slope workers. These payrolls would generate sales, jobs, and tax base in the communities where the Slope workers live.

Figure 1 shows the size and composition of Alaska employment and payroll which the development and production of the field would generate after subtracting onsite jobs likely to be filled by nonresidents. Field development would be spread over several years, so the number of annual average jobs produced in the peak year would be about 500 with a payroll of \$25 million. As the figure shows, the majority of those jobs would be offsite in vendor businesses, in the communities where the workers reside, and in the public sector. During production the number of jobs would fall to under 250 for an average year, and the pattern again is that most of the jobs would be offsite. However, in both the development and production phases, the payrolls are concentrated onsite.

The actual economic impact in a real situation would depend on the development and production plan as well as the resident share of employment and purchase of other inputs. But once the field size has been estimated, the budget and with it the economic effect would be constrained within a narrowly defined range. Basically the budget must be economically feasible, and the economic effect would flow from that budget. While the economic effects are clearly defined once the development strategy has been identified, the revenues that the field would generate are much less so since they are sensitive to actual, rather than anticipated, production, wellhead price, and the tax and royalty rates in place.

The range of variation of state revenues from production, primarily royalties but also the state share of the property tax and the corporate income tax, in response to variation in these parameters is shown in Figure 2. For example, if over its life the field were to produce 150 million barrels, the wellhead averages \$8.31 (1995 \$) and the royalty rate is 6%, production revenues would be \$84 million. For the range from low to high price, production, and royalty, the range of production revenues is \$29 to \$328 million.

Two other sources of revenue, from the "full pipeline effect" and the payrolls generated by the new jobs, are less volatile and significant. Adding production from a marginal field to the existing throughput of the Alyeska pipeline marginally reduces

the tariff on existing throughput and increases its wellhead value. This "full pipeline effect" would increase severance tax and royalty revenues from production from all North Slope fields. The payroll generated by the marginal field activity represents a tax base which could be tapped to pay some of the state government costs imposed by the new workers and their families. Although the state currently has no vehicle to allow these workers to pay for some of the public services they receive, the tax capacity represented by their payroll should be included as a potential revenue source.

The costs to state government from marginal field development consist of management costs such as environmental monitoring, tax auditing, etc., and more importantly the costs of providing services for the families of the new workers both onsite and in Alaska's urban centers. These costs can be divided into those which support oil industry families, vendor families, and other private and public workers in the urban centers. The public management costs are about \$7 million, and the population-related costs are about \$4.4 million, totaling about \$51 million.

These public sector costs are contrasted with the range of revenues which the field could produce over its life in Figure 3. Subtracting the costs from the revenues yields a range for the state revenue "dividend" (Figure 4), which is the tax base generated by the marginal field over and above the amount necessary to pay for the costs of state government imposed by the field. The "dividend" ranges from \$1 to \$300 million depending upon production, price, and royalty rate.

Figure 5A shows the range of production revenues introduced as Figure 2, converted to an annual equivalent. It contrasts the potential range of revenues for the marginal field with the total annual revenues to the state generated by other natural resources based on a recent analysis of the sources of state revenues prepared by Legislative Research in 1993. The range for the marginal oil field is clearly consistent with the total revenues to the state from most other natural resources.

Finally, Figure 5B compares the state's natural resource revenues from various resources with the state's resource management expenditures for those same natural resources. The marginal oil field is the only case where resource management costs are covered by the revenues generated, and the substantial revenues are available to contribute to the general costs of government.

FIGURE 1A. MARGINAL FIELD ECONOMIC EFFECT  
RESIDENT EMPLOYMENT

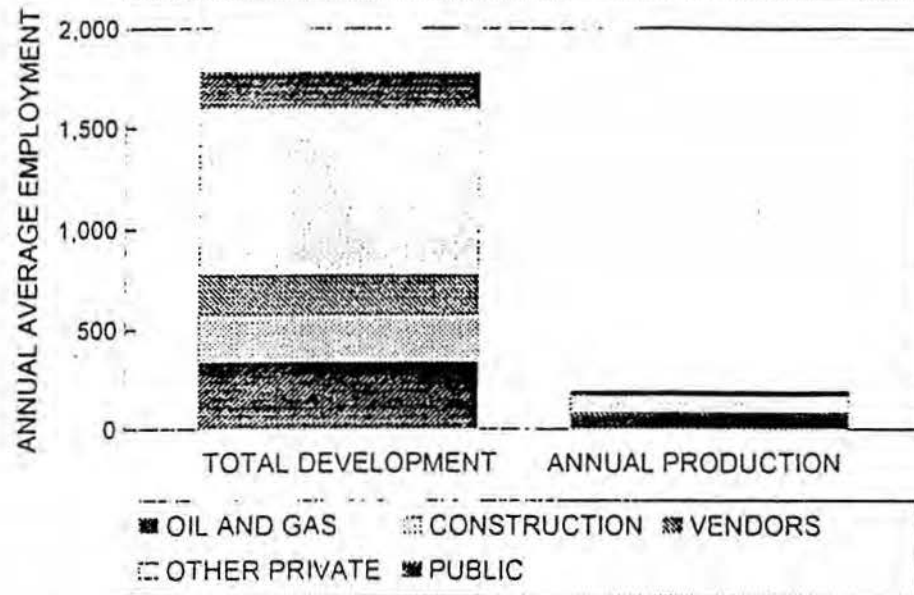
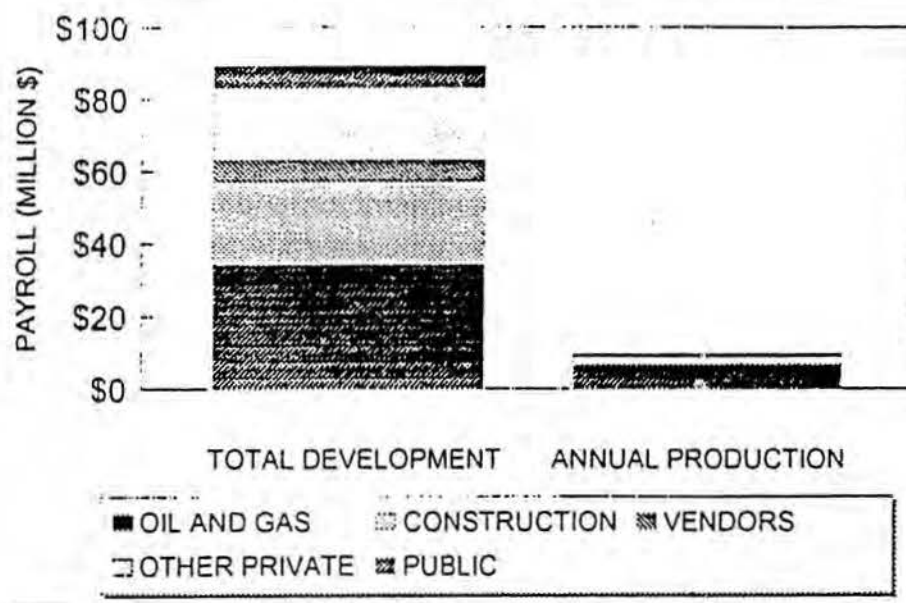
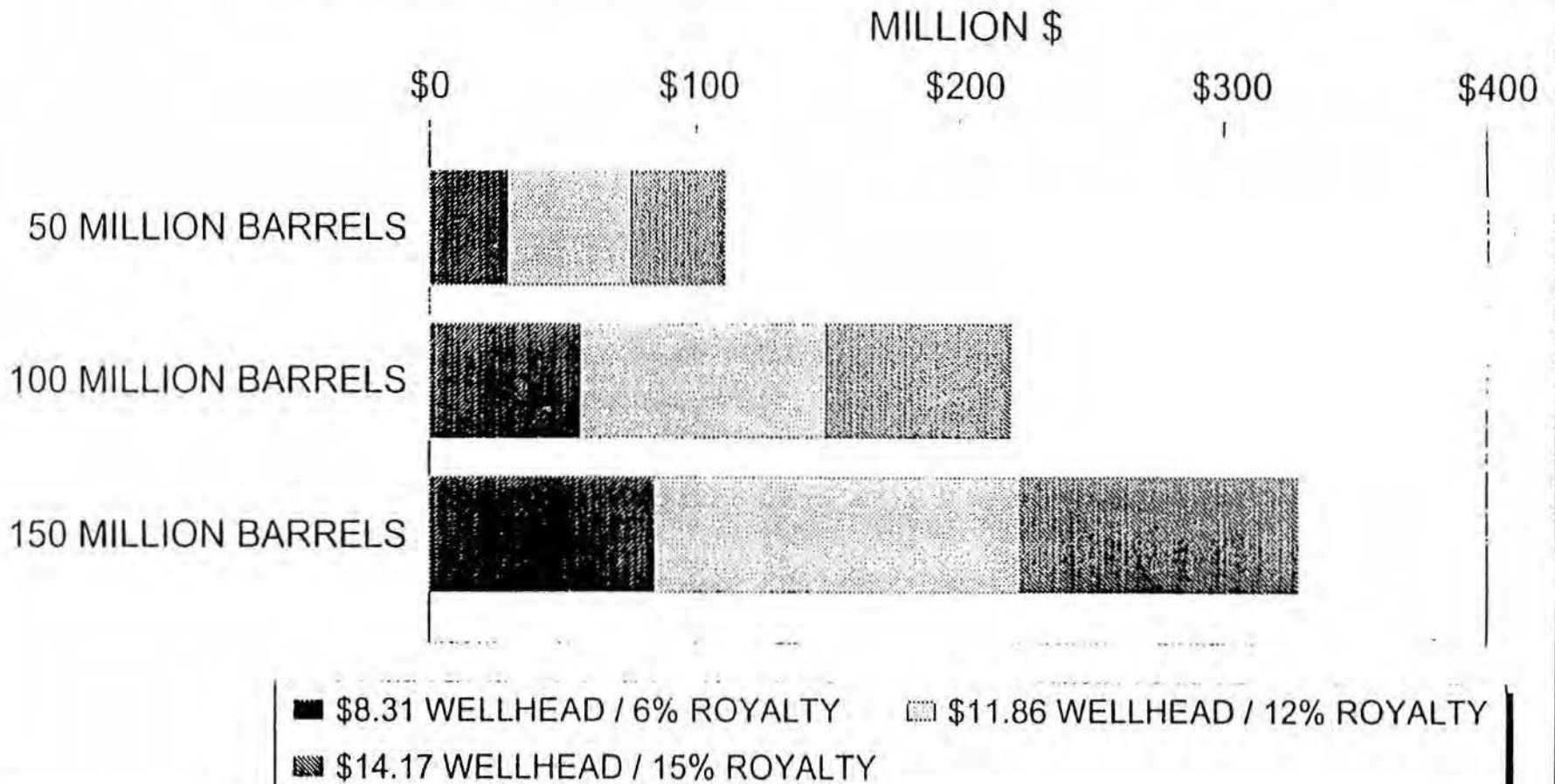


FIGURE 1B. MARGINAL FIELD ECONOMIC EFFECT:  
RESIDENT PAYROLL

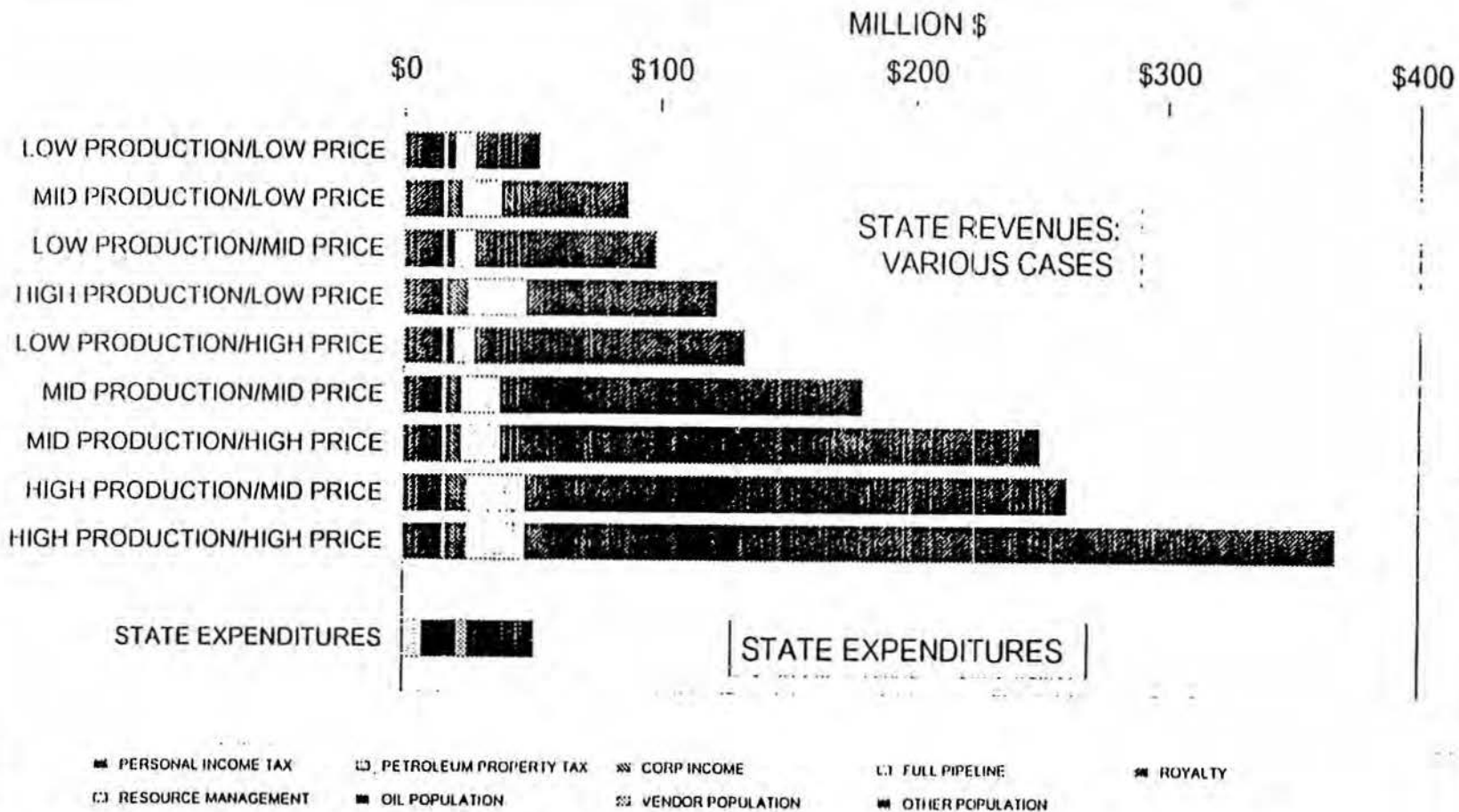


**FIGURE 2. MARGINAL FIELD PRODUCTION REVENUES**  
 SENSITIVITY TO PRODUCTION, WELLHEAD PRICE, AND ROYALTY RATE



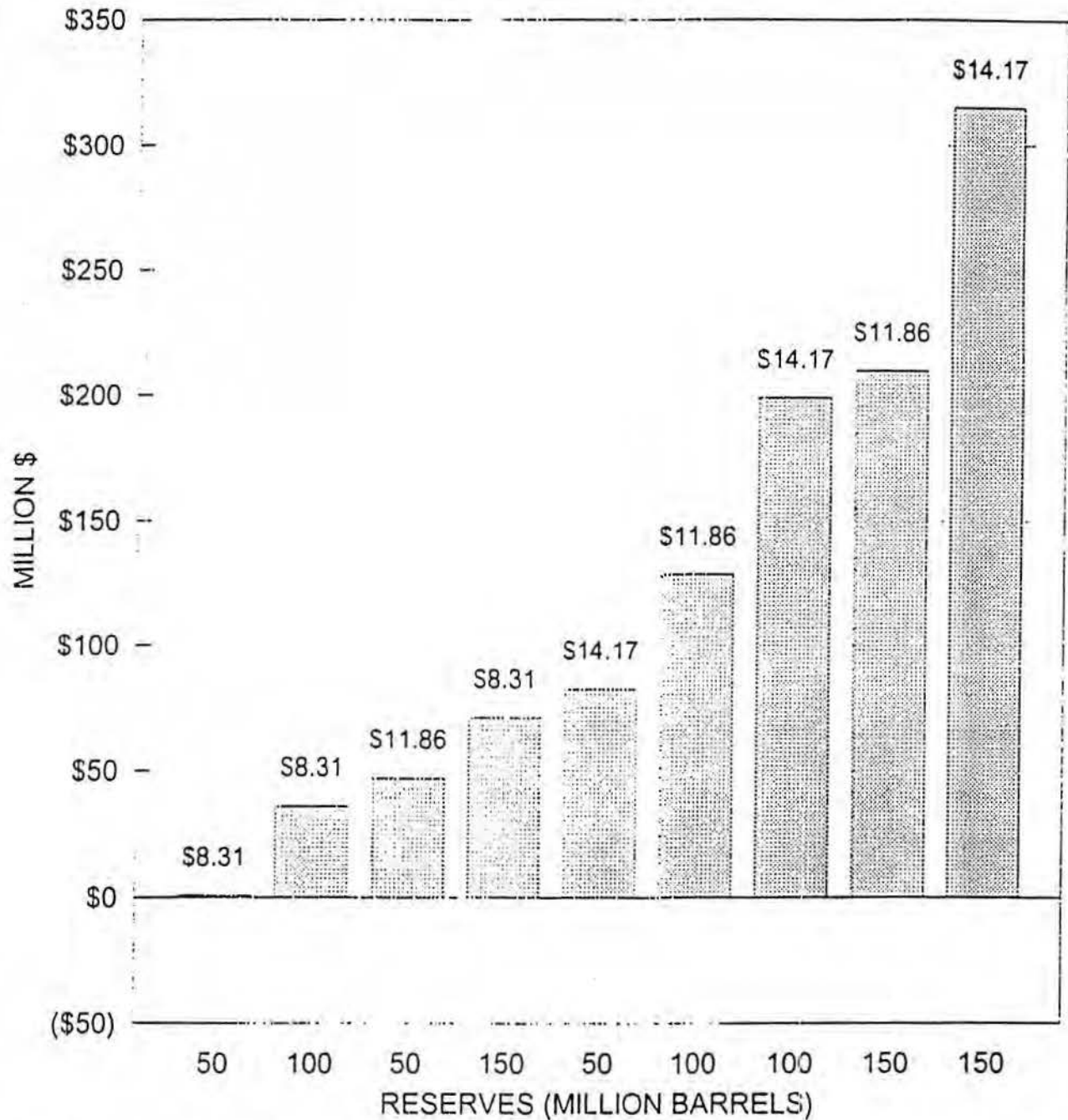
REVENUES OVER THE LIFE OF THE FIELD

**FIGURE 3. STATE REVENUES AND EXPENDITURES:  
LIFE OF THE FIELD**



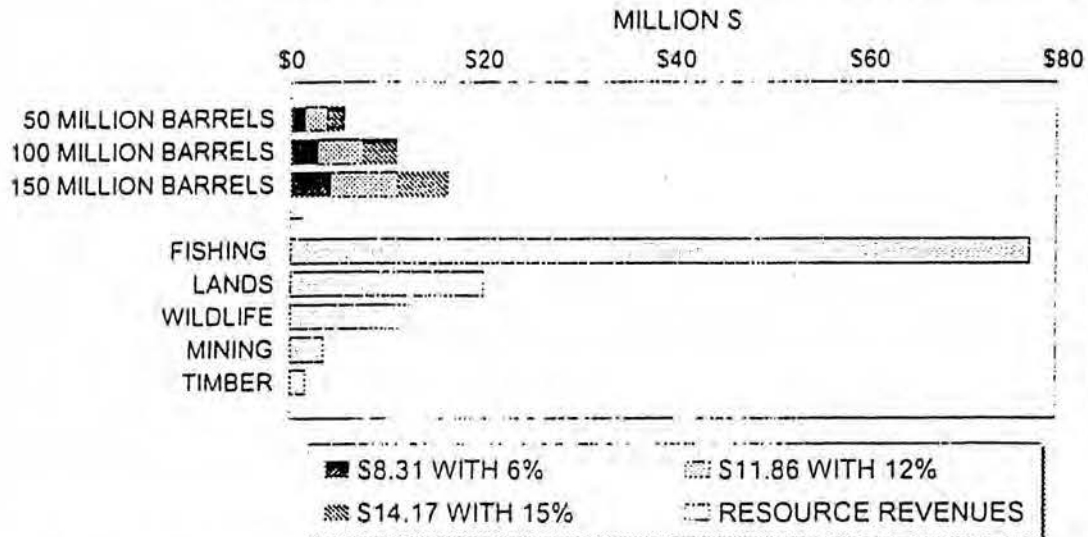
# FIGURE 4. STATE REVENUE "DIVIDEND"

VARIATION IN RESERVES, PRICE, AND ROYALTY RATE



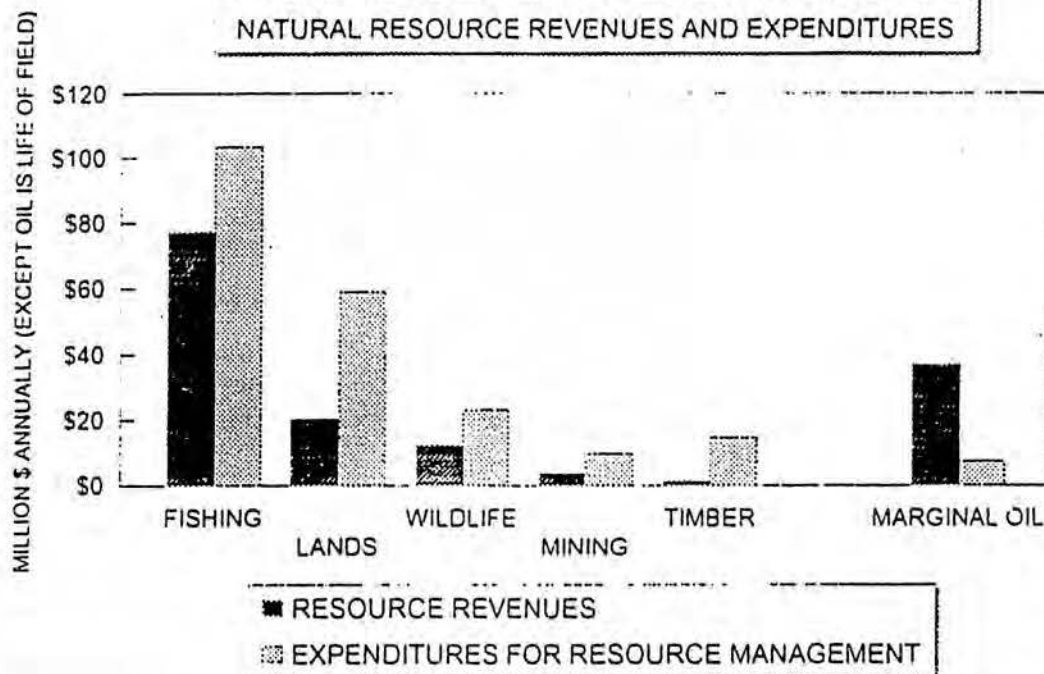
REVENUES IN EXCESS OF AMOUNT NEEDED  
TO PROVIDE NEW PUBLIC SERVICES

**FIGURE 5A. ANNUAL MARGINAL FIELD PRODUCTION REVENUES  
COMPARISON TO TOTAL REVENUES FROM OTHER RESOURCES**



SOURCE FOR OTHER RESOURCES: LEGISLATIVE RESEARCH 1993

**FIGURE 5B. STATE OF ALASKA  
NATURAL RESOURCE REVENUES AND EXPENDITURES**



SOURCE: LEGISLATIVE RESEARCH, 1993.  
EXCEPT MARGINAL OIL IS LOWEST REVENUE CASE FROM TEXT NET OF INCOME AND SALES TAX RE



## CALIFORNIA INDEPENDENT PETROLEUM ASSOCIATION

Main Office: 1112 "I" Street, Suite 350, Sacramento, CA 95814 • 916-447-1177 • Fax 916-447-1144  
Environmental Affairs Office: 5201 Truxtun Avenue, #119, Bakersfield, CA 93309 • 805-633-3119 • Fax 805-633-3191

June 21, 1995

JUL 05 1995

Representative Joe Green  
Alaska State Legislature  
Alaska State Capitol  
Juneau, Alaska 99801

**RE: CIPA Support for HB 325, the "Heavy Oil Royalty Suspension" Bill**

Dear Representative Green:

The California Independent Petroleum Association (CIPA) wishes to express its strong support for HB 325, provided that Congress lifts the ban on the export of Alaskan North Slope crude oil which appears likely to happen soon. CIPA represents over 550 production, exploration and service companies operating in California.

This measure proposes a simple yet effective incentive for independent producers, including those in California, to invest in heavy oil projects in Alaska. As you know, approximately two-thirds of California's oil production is heavy oil and this state's producers know only too well the difficult investment climate for heavy oil and the large role incentives can play in stimulating such activity.

Simplifying the process of obtaining incentives is critical for the independent producer because of limited manpower resources. And in order to be an effective inducement to increase activity, the incentive must significantly affect an independent's economics. HB 325 appears to accomplish both of these goals.

Please do not hesitate to contact me at (916) 447-1185 if I may be of assistance in your deliberations on this proposal.

Sincerely,

A handwritten signature in black ink, appearing to read "Dan K", with a long horizontal line extending to the right.

Daniel P. Kramer  
Executive Director

Revision Date: \_\_\_\_\_ Dept. Affected: Revenue  
 Title: Royalty Suspension: N. Slope Heavy Oil BRU: Revenue Operations  
 Component: Oil and Gas Audit  
 Sponsor: Representative Green  
 Requestor: H (O&G) Committee COMPONENT SERIAL NO. 115

Expenditures/Revenues: (Thousands of Dollars)

OPERATING EXPENDITURES	FY 97	FY 98	FY 99	FY 00	FY 01	FY 02
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
<b>TOTAL OPERATING</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>

CAPITAL EXPENDITURES						
----------------------	--	--	--	--	--	--

CHANGE IN REVENUES ( )	-1,800.0	-2,400.0	-5,700.0	-11,000.0	-12,000.0	-24,500.0
------------------------	----------	----------	----------	-----------	-----------	-----------

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other						
<b>TOTAL</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>

Estimate of any current year (FY96) cost \$ \_\_\_\_\_

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

(See Attached Analysis)

Prepared by: Chuck Logsdon  
 Division: Oil & Gas Audit  
 Approved by Commissioner: *Walter Long*  
 Agency: Department of Revenue

Phone: 276-1363 ext. 265  
 Date: 1/19/96  
 Date: 1/19/96

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Analysis of Bill/Program Effects

This bill has two main parts. The first addresses the ability of the Commissioner of the Department of Natural Resources to modify the payment of royalty on leases, and the second suspends the royalty obligation for wells producing less than 500 barrels a day of Alaska North Slope (ANS) heavy oil for five years of production.

The Department of Revenue Fall 1995 forecast assumptions for Alaska North Slope heavy oil production, wells, and revenues FY 1997 to FY 2002 is contained in the following table:

	Production	Wells	Severance Tax	Royalties
1997	3000 bb/d	14	0	\$1800 thousand
1998	4000	16	0	2400
1999	5700	22	0	5700
2000	11100	42	0	11000
2001	18100	65	0	12000
2002	24500	85	0	24500

The bill would effectively reduce projected heavy oil royalties to zero.

# Alaska State Legislature

WHILE IN SESSION  
CAPITOL BUILDING  
SHEARER AVENUE, ANCHORAGE, ALASKA 99506-1142  
PHONE: 465-4401  
FAX: 465-4415

INTERIM ADDRESS  
177 WEST 4TH AVENUE  
ANCHORAGE, ALASKA 99501  
PHONE: 465-4415  
FAX: 465-4415



CO-CHAIR, RESOURCES COMMITTEE  
VICE CHAIR, JUDICIARY COMMITTEE  
MEMBER, STATE AFFAIRS COMMITTEE

FINANCE SUBCOMMITTEE  
DEPT. OF NATURAL RESOURCES  
DEPT. OF COMMERCE & ECONOMIC DEVELOPMENT  
DEPT. OF ENVIRONMENTAL CONSERVATION

Representative Joe Green  
District 12

## 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 500 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.

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 "C" STREET, SUITE 1380  
ANCHORAGE, ALASKA 99503-5948  
PHONE: (907) 269-8784

March 22, 1996

The Honorable Mark Hanley  
Alaska State Representative  
State Capitol, Room 507  
Juneau, Alaska 99801-1182  
MAIL STOP 3101  
FAX 1-907-465-2418

Dear Representative Hanley:

I received the proposed amendments from your office on March 19. These amendments do two things (other than "housekeeping").

First, they clarify that only new grass roots wells are eligible for royalty relief, and, further, they describe what types of other "well operations" will not be considered for relief. As with any list, it is impossible to contemplate every variation of well type or well operation (nor can it envision future technology). Nonetheless, I believe this gives a pretty clear message as to what the legislative intent is. This intent is further clarified by the new "initial production" language you inserted. I suggest the following amendment to round out the concepts you propose:

Page 2, after line 30

2 #

Adopted

insert "(E) for purposes of calculating the first 500 barrels per day of production from a well, production from dual completions and other forms of multiple completions in a well is to be added together and counted as production from a single well."

Second, they clarify that "field cost" deductions will not be allowed from any royalty free production of heavy oil. The bill does not define "field costs." I suggest the following amendment to clarify what I believe your intent is:

Page 2, after line 30

# 3

Adopted

insert "(F) for purposes of defining field costs in this subparagraph, field costs include ~~the~~ those ~~costs~~ outlined in AS 38.05.180(f)."

LEASE or UNIT expenses

The bill appears to suggest "reported royalty" will be the actual royalty. This needs further clarification, and I will work with the legislature to come up with more appropriate language.

3/22/96  
ATTACHMENT 2

The Honorable Mark Hanley  
Alaska State Representative  
March 22, 1996  
Page 2

I further suggest two "housekeeping" amendments:

*Adopted*

Page 2, line 10

*Am 4*

delete "finished goods"  
insert "industrial commodities"

Page 2, line 22

*Am 5 Adopted*

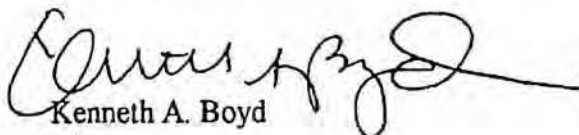
insert after the word "performed":  
"at least once monthly"

*concept*

*19 or quarter*

I continue to have concerns with the overall approach taken in the legislation and the proposed 500 b/d, \$15/b and 10 year open window trigger points. I still believe that HB-207 is the proper vehicle to determine both the need for, and level of, royalty relief. Heavy oil has an important role to play in the future on the north slope. Hopefully we can continue to discuss our differences and reach a common understanding.

Sincerely,



Kenneth A. Boyd  
Director

032296mh.kb

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SIMPSON, TILLINGHAST, SORENSEN & LORENSEN  
A PROFESSIONAL CORPORATION

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RONALD W. LORENSEN  
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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

February 22, 1996

The Honorable Mark Hanley  
Alaska State Representative  
Co-Chair House Finance Committee  
State Capitol, Room 507  
Juneau, Alaska 99801-1182

Re: HB 325; Royalty floor  
Our file: 553.7

Dear Representative Hanley:

The purpose of this letter is to share OXY USA Inc.'s ("OXY") views on the option of creating a royalty floor in HB 325. Under this option, royalties would not be suspended for a period of 5 years; rather, royalties during an initial development period would be reduced to 2 or 3 percent. As the attached chart indicates, if the committee's desire is still to craft an effective incentive--that is, one that appears calculated to push heavy oil development over the 15 percent hurdle-rate threshold--then:

(1) with a 2 percent "floor," the incentive period would need to be extended to six years from the initial drilling of each new well; and

(2) with a 3 percent "floor," the incentive period would be eight years.

OXY believes that a royalty floor would make HB 325 a materially less effective incentive without yielding any corresponding revenue benefits to the state. For these reasons, we would oppose its inclusion in the legislation. To explain:

1. **A floor's impact on the bill's effectiveness as an incentive.** The purpose of HB 325 is to spur capital investment in new heavy oil drilling by: (a) improving each well's rate of return; and (b) reducing the capital recovery period to a commercially reasonable term. Either a 2%/6-year, or 3%/8-year, "floor" would yield the same rate of return as a 5-year suspension--as the attached graph illustrates. However, by extracting royalty payments at the outset of production, a floor would impair initial cash flow and resultantly prolong capital recovery. As you know, even a five-year royalty

suspension yields a 5.4 year projected capital recovery period--still longer than the commercial five-year standards. *See White Paper*, p. 37. Any material adverse impact on that already-marginal recovery period could adversely affect investment decisions.

Moreover, a floor would increase the investor's risk to declining oil prices. With the bill's \$15/bbl. ceiling, the state is protected from high-side risk. However, if oil prices fall, the resultant losses to the operator would be aggravated by the need to pay a royalty on gross production value. The increased risk occasioned by a royalty floor during the capital recovery period will undoubtedly be considered by investment decision-makers.

For these reasons, jurisdictions seeking to encourage new capital investment (as opposed to prolonging an exiting field's economic life) have uniformly chose to suspend payment obligations at the outset of development, rather than spread reduced payments over a longer period. *See White Paper*, p. 35. <sup>1/</sup> Indeed, the Arthur D. Little Report specially mentioned royalty suspensions as an effective vehicle for encouraging investment in marginal fields. *Id.* at 34. In sum, a royalty suspension would be consistent with precedent and prevailing wisdom. The approach envisioned by a "floor" would not be.

2. **A floor's impact on state revenues.** On a nominal dollar basis, the royalty suspension maximizes state revenues from heavy oil development. <sup>2/</sup> This is because heavy oil wells: (a) have low initial production rates; (b) decline very slowly; and (c) have unusually long lives. Indeed, in the White Paper OXY showed that, for these reasons, the state would receive \$800,000 more in royalties for each well under a royalty suspension than from a five-percent royalty over the life of the field. *White Paper*, p. 39.

As a result, it is in the state's interest to front-load the incentive, and have it expire at the earliest possible time.

HB 207 requires a 3-5% royalty floor. That is because that law's drafters had in mind more conventional oil fields with perhaps a 20-year field life, and a 20% annual production decline. In these more typical situations, the state does have a clear interest in capturing a share of initial action. Conversely, with a 41-year field life, and only a 10% annual production decline rate, the state gains nothing, and at some point actually loses revenues, by dragging out an incentive simply for the purpose of capturing a share of initial production.

If you have further questions on this matter, please do not hesitate to ask.


---

<sup>1/</sup> It's true that most of these other incentives suspend a state's severance tax, rather than royalties. However, and as the White Paper explains, this is only because oil production in other states generally occurs on private land, and therefore the severance tax forms the principal government "take" from oil production.

<sup>2/</sup> It remains our understanding that the State of Alaska generally predicates its economic analyses on nominal dollars.

Sincerely,

SIMPSON, TILLINGHAST,  
SORENSEN & LORENSEN



Jon K. Tillinghast

cc: Rep. Joe Green  
Rep. Norman Rokeburg  
Members, House Finance Committee

JKT:tg

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

FEB 02 1996

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JON K. TILLINGHAST

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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.: 840.2

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. <sup>1/</sup>*

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

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<sup>1/</sup> 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.<sup>2/</sup> The effort, unfortunately, is procrustean.<sup>3/</sup> The goals of HB 325 can't be forced into HB 207's structure for six reasons:

### *I. 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 38.05.180(j)(1)(B)--might be made to fit Schrader Bluff.<sup>4/</sup>

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.<sup>5/</sup>

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<sup>2/</sup> 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.

<sup>3/</sup> 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.

<sup>4/</sup> 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.

<sup>5/</sup> 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 38.05.180(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." <sup>6/</sup> 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," <sup>7/</sup> or what Chair Rokeburg more directly described as "old uneconomic fields...e.g. Cook Inlet." <sup>8/</sup>

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.*

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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.

<sup>6/</sup> Minutes, Senate Finance Committee, May 8, 1995.

<sup>7/</sup> *Id.* at 3.

<sup>8/</sup> 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."<sup>9/</sup> Indeed, and as Mr. Boyd explained to the Senate Finance Committee, the Conoco/OXY royalty relief application had been decided under that clause.<sup>10/</sup>

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.*<sup>11/</sup>

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:

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<sup>9/</sup> *Minutes, House Oil and Gas Committee*, March 9, 1995 at 4.

<sup>10/</sup> *Minutes, Senate Finance Committee*, May 8, 1995.

<sup>11/</sup> *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;<sup>12</sup> / 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.

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<sup>12</sup> / AS 33.05.180(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,<sup>13/</sup>

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

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<sup>13/</sup> 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.

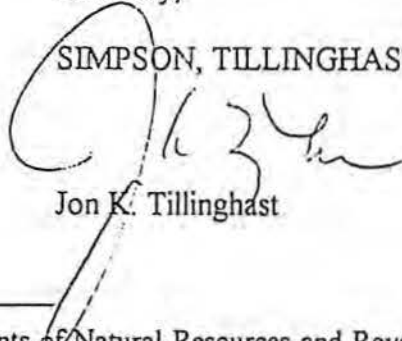
HB 325, on the other hand, focuses only on a single, well-understood development challenge. As a result, it invites a reassertion of legislative involvement in this sphere, if the legislature chooses to take that opportunity. In part, that's because there seems something of a consensus that ANS heavy oil is unlikely to be developed without an effective incentive.<sup>14/</sup> 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

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<sup>14/</sup> 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.

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



Retroactive changes to leases are unfair advantages to individual companies, harming competition, and possibly neglecting the State's best interest.

To accommodate the economic difficulties of developing heavy crude the State should never forgo the royalty completely. With some royalty being paid, there is a formal relationship and interest in the health of the well by the owner (State) and the producer (lease holder).

In many businesses, (film, music, TV) royalty negotiations are standard. There are many models of shared risk at the investment level, but, over the life of the project all royalties are paid. Benefit now, pay later, but, you should come back and pay.

As the chairman of House Oil and Gas said on 1/23/96, "... (it's) self executing". But, I urge you not to shoot Alaska in it's future earnings.

Appendix Alaska

Alaska Onshore/Near Shore

Field Size (mmb)	Appraisal Wells			Development Cost (\$/bbl)	First Oil (Years)	Production Profile		Operating Costs			
	Number**	Cost/Well (\$mm)	Duration (Years)			Peak Uptake (%)	Field Life (Years)	Total (\$/bbl)	Variable (\$/bbl)	Fixed (\$/bbl)	Tariff (\$/bbl)
10*	1	10	2	6.0	4	14	12	6.6	3.2	3.4	3.0
25*	1	10	2	4.7	4	14	12	5.1	2.4	2.7	3.0
50*	2	10	2	3.4	4	13	12	4.0	1.8	2.2	3.0
125	3	10	3	2.8	4	12	15	3.1	1.4	1.7	3.0
250	4	10	3	2.5	5	11	20	2.5	1.1	1.4	3.0
500	5	10	3	2.1	5	10	22	2.1	1.0	1.1	3.0

\* TAPS tariff only shown, \$2.00/bbl for TAPS owner

4.0 → 11.1  
 4.8 → 12.1

02/13/96 TUE 12:14 FAX 915 885 5931 OXY HEAVY OIL TEAM

# Alaska State Legislature

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CO-CHAIR, RESOURCES COMMITTEE  
VICE CHAIR, JUDICIARY COMMITTEE  
MEMBER, STATE AFFAIRS COMMITTEE

FINANCE SUBCOMMITTEES:  
DEPT. OF NATURAL RESOURCES  
DEPT. OF COMMERCE & ECONOMIC DEVELOPMENT  
DEPT. OF ENVIRONMENTAL CONSERVATION

## Representative Joe Green

District 10

February 2, 1996

Mr. Ken Boyd, Director  
Division of Oil & Gas  
Department of Natural Resources  
3601 "C" Street, Suite 1380  
Anchorage, Alaska 99503

Mr. Boyd,

Thank you for the copy of your letter responding to Representative Bill Williams' questions about the applicability of AS 38.05.180 (j) in reducing the royalty for heavy oil.

I appreciate the position you and Commissioner Shively share on heavy oil incentives, and as well, I appreciate the proposed amendment language offered; however, I feel that neither AS 38.05.180(j), nor the proposed amendment achieves the goal I set when I introduced HB 325.

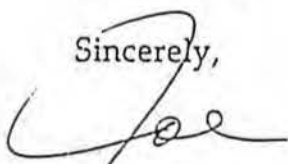
As I stated after your testimony on HB 325 last Friday, the incentives offered in HB 325 are not discretionary. I believe this is the most important aspect of the bill. To allow DNR to have discretionary authority to grant the royalty reduction would introduce an unacceptable degree of uncertainty. As you well know, in the eyes of investors, uncertainty equals risk, and risk is the major element we are attempting to diminish.

The committee substitute offered by the Oil & Gas Committee adequately protects the state with a limited window of opportunity, and a production and price ceiling above which the full royalty applies. The issue of a minimum royalty has been discussed, and it may be possible to discuss this issue further, as an amendment to HB 325, or as a modification to AS 38.05.180(j).

Mr. Ken Boyd  
February 2, 1996  
Page 2

I remain open to proposals to amend AS 38.05.180 (j) to clarify that it can be used to adequately reduce the risk of producing heavy oil to interested potential developers. However, at this time I still feel that the certainty of an automatic royalty reduction is necessary and therefore cannot support discretionary uncertainty in HB 325.

Sincerely,

A handwritten signature in black ink, appearing to read "Joe", written over a horizontal line.

Representative Joe Green, Co-Chairman  
House Resources Committee

TONY KNOWLES, GOVERNOR

## DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 "C" STREET, SUITE 1330  
ANCHORAGE, ALASKA 99503-5948  
PHONE: (907) 269-8784

January 30, 1996

The Honorable Bill Williams  
Alaska State Representative  
State Capitol, Room 128  
Juneau, Alaska 99801-1182

Dear Representative Williams:

You asked whether HB 207, passed last session, could be used to grant royalty relief for the production of "heavy oil." The division's short answer is yes. Nevertheless, because of the concerns expressed in the hearing on January 24 about the applicability of HB 207 to heavy oil production, the administration would support an amendment to HB 207 to provide explicitly that it applies to heavy oil production.

Subject to several provisions designed to protect the state's interests, HB 207 grants authority to the commissioner of the Department of Natural Resources to modify the existing royalty rate "to allow for production that would not otherwise be economically feasible" for any one of three types of oil or gas pools. In essence, the three are:

1. To allow production from an oil or gas pool that has been delineated, but has not previously produced ("New Pool").
2. To prolong the economic life of an oil or gas pool as costs per barrel or barrel equivalent increase ("Declining Pool").
3. To reestablish production from a shut-in oil or gas pool ("Shut-in Pool").

For purposes of HB 207, heavy oil production is no different from any other type of oil production. In other words, HB 207 would apply whether the oil production consisted of heavy, medium, or light production. If a company wished to produce heavy oil from a Shut-in Pool, it could be granted royalty relief under HB 207. For example, heavy oil production from ARCO's portion of the Schrader Bluff pool (which ARCO calls West Sak) that has been shut-in could be granted royalty relief. The same would be true for heavy oil production from a Declining Field or New Field.

Oxy and BP have a specific concern about whether heavy oil production from the Schrader Bluff pool within the Milne Point Unit could qualify under HB 207. Again the issue is not whether heavy oil production could qualify; rather it is whether the Schrader Bluff pool fits within one of the three types of pools listed in HB 207.

In the division's opinion, the Schrader Bluff pool does not meet the definition of a New Pool because the Schrader Bluff production has been sold. Arguably, the Schrader Bluff pool meets the definition of a Shut-in Pool. The Arco portion of the Schrader Bluff pool is currently shut-in. The Tract 14 pilot project for production from the Oxy and BP portion was shut-in from 1992 to 1994. If the production remains uneconomic, as the companies asserted in their testimony and the pilot project was stopped, the Schrader Bluff pool would clearly qualify as a Shut-in Pool.

The Honorable Bill Williams  
January 30, 1996  
Page 2

The most applicable definition to the Schrader Bluff pool is the Declining Pool definition, number 2 above. First, granting royalty relief could "prolong the economic life of" the Schrader Bluff pool production. Second, the costs per barrel increase with heavy oil production. Most importantly, granting relief, assuming it was justified, would be consistent with HB 207's primary purpose "to allow for production that would not be otherwise be economically feasible." It appears that HB 207 could be applied to heavy oil production from the Milne Point Unit.

Nevertheless, some of the companies and representatives have expressed concern about the applicability of HB 207 to heavy oil production from the Milne Point Unit. To alleviate any concern about HB 207's applicability to the Milne Point Unit, the administration would support an amendment to HB 207 to make heavy oil explicitly included within the purview of HB 207. 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 the production from an oil pool containing heavy oil, defined as production with American Petroleum Institute weighted average gravity of 20 degrees or less; or

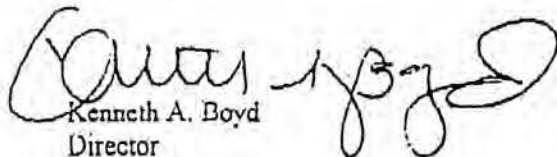
Such an amendment is preferable to HB 325 because it would subject any relief to the protection of the state's interests afforded by HB 207. Specifically, it would require a complete and thorough economic analysis of heavy oil royalty relief, which is lacking in HB 325. Indeed, no state agency has been given the detailed backup data that presumably supports the economic assertions contained in the white paper prepared by BP and Oxy. HB 207 would also provide for public and legislative comment before any relief is granted. Finally, it would allow any relief granted to be conditioned to change if the bases upon which the relief is granted change.

By passing HB 207, the legislature adopted a consistent policy that would treat all players fairly and equally. HB 207 allows for "fiscally efficient" royalty terms. HB 325 is not fiscally efficient because it is not sensitive to profitability. It reduces the state's royalty without a showing of necessity by the companies or a guarantee of anything in return to the state for granting relief. Despite the companies' contrary protestations, they can have certainty of relief under HB 207 before making any investment.

Undeniably, HB 207 is not as administratively simple as HB 325 because it requires a complete review. The long debate over HB 207 last session convinced me that although both the legislature and the governor want expedited development of Alaska's oil and gas resources, they want this done with proper scrutiny. This scrutiny, clearly present in HB 207, is lacking in HB 325.

I hope this information is helpful to you. If you have any further questions, please feel free to call me.

Sincerely,

  
Kenneth A. Boyd  
Director

TONY KNOWLES, GOVERNOR

**DEPARTMENT OF NATURAL RESOURCES**

DIVISION OF OIL AND GAS

3601 "C" STREET, SUITE 1380  
ANCHORAGE, ALASKA 99503-5948  
PHONE: (907) 269-3734

February 9, 1996

Mr. John Morgan  
BP Exploration (Alaska) Inc.  
900 East Benson Boulevard  
P.O. Box 196612  
Anchorage, Alaska 99519-6612

Mr. Edward K. Behm  
OXY USA Inc.  
6 Desta Drive, Suite 6000  
P.O. Box 50250  
Midland, Texas 79710-0250

Dear Sirs:

BP Exploration (Alaska) Inc. ("BP") and OXY USA Inc. ("OXY") have made representations to the House of Representatives in support of HB 325 concerning the feasibility of heavy oil development in the Milne Point Unit, Schrader Bluff Participating Area in both a "white paper" dated January 22, 1996, and in testimony to the House Subcommittee on Oil and Gas, the House Resources Committee and the House Finance Committee. Further, BP and OXY offered to make detailed back-up data available to the Division of Oil and Gas. As a result, the Division has been asked by members of the Alaska State Legislature to review the economics of heavy oil development at the Milne Point Unit in order to evaluate the provisions of HB 325. On February 8, 1996, the Division received from OXY a summary sheet titled "Critical Assumptions." More information is needed to provide background to the bottomline figures presented so far, similar to the information OXY previously provided for its prior Milne Point Unit royalty reduction request and the information BP provided to assist the Division in evaluating BP's economics for another field.

In order to perform the requested review, the Division will need detailed and comprehensive data from BP and OXY supporting the analyses that both companies have previously presented. This data must cover both the full Schrader Bluff pool development and, because the proposed legislation is currently structured on a per-well basis, the per-well economics of the Schrader Bluff pool. In both cases, the companies should provide the incremental company economics that are projected to accrue to the project through facility sharing arrangements, pipeline tariffs, tax benefits, etc. We recognize that each company's economic assessment is different, and so each company should provide its own analysis of these impacts.

Mr. John Morgan  
BP Exploration (Alaska) Inc.  
February 9, 1996

Mr. Edward J. Behm  
OXY USA Inc.

*Handley*

Per-well economics The "Critical Assumptions" sheet provides a summary guide to the kind and detail of information required by the Division. Supporting data necessary includes:

1. Production and Revenues: the historical data for each Schrader Bluff well, including initial production rates, decline rates and per-well reserves, plus all back-up data supporting the chart presented in BP's Finance Committee presentation on February 8, 1996 ("BP's Presentation") entitled "Schrader Bluff Typical Well Production Rate vs Time (years)."
2. Drilling and equipment costs: historical data for each Schrader Bluff well, plus an analysis of the cost reduction trends including any documents supporting the statement made in BP's Presentation that the 1995 Schrader Bluff development program has demonstrated that drilling costs have been reduced, that completion costs have remained constant, and that ESP life has been improved. Provide the results of the well performance and technical study referred to in BP's Presentation as soon as it is available.
3. Supporting data for the dry hole cost assumption of 86.80% of producing well costs and for the 90% success rate assumption.
4. Back-up data and analysis for the \_\_\_\_\_ associated facility cost, including an explanation of the calculation used. This component should be also thoroughly documented in the Schrader Bluff development economics.
5. Complete detail and analysis for the \_\_\_\_\_ operating expense estimate and a detailed explanation of the \_\_\_\_\_ for fixed per-well operating expense. The operating expenses should also be thoroughly documented in the Schrader Bluff pool development economics. Forecasts of both this component and item 4 above must be supported by historical (actual) data.
6. Complete detail and analysis for OXY's calculation of \_\_\_\_\_ severance tax and property tax percentages calculated on revenue, including an explanation of why revenue was used instead of the oil value and property assessment. If BP has different values, please provide those values plus the supporting detail.

Schrader Bluff pool development. It is the Division's understanding that the decision to develop the Schrader Bluff is not made on a well-by-well basis. For example, Mr. Policky testified that development of the Schrader Bluff pool would require upgrading of the central production facility serving all horizons in the unit. BP and OXY should each provide the Division with the complete analysis of the whole project, including any documentation describing the "full development scenario" of 350-400 wells presented in OXY's Critical Assumption sheet versus any documentation describing the 230 well

Mr. John Morgan  
BP Exploration (Alaska) Inc  
February 9, 1996

Mr. Edward J. Behm  
OXY USA Inc.

development scenario represented in the BP's Presentation in a chart titled "Additional Production from Heavy Oil by Development Year." Included in this information should be the same kind of analysis that would be presented to corporate decisionmakers who would ultimately commit resources to the development of the Schrader Bluff pool. Additionally, please provide the economic analysis of facility expansion and the way that such capital expenditures are to be allocated to Schrader Bluff production. Potential areas of risk should be identified and an explanation of how they were incorporated into the assessment.

Other Information Needed:

1. Any BP documents prepared for the purpose of seeking financial approval and commitment to acquire its interest in the Milne Point Unit including any *pro forma* finance memoranda.
2. Copies of all AFEs (both accepted and rejected) for any capital expenditures relating to the Schrader Bluff pool including the \$15MM expenditures for the recent 6 new wells, well completions, and additional technical study.
3. Internal documents that explain the company's approval and sanction process for a major investment, including economic hurdle parameters, IRR, NPV, PW, any other financial criteria required by the company's evaluation, corporate, federal and state income tax rates, cost of capital, and Schrader Bluff contribution to company incremental economics. NOTE: BP has already provided all but the Schrader Bluff contribution to company incremental economics and need not duplicate information provided.
4. From OXY, an EXCEL-type spreadsheet (on disk to speed analysis) detailing how the 12.8 and 15.9 rates of return, the 6.5 and 5.4 year pay back periods, the \$115M net discounted cash flow, negative \$307M discounted cash flows, and the total per-well royalties undiscounted of \$1843M and \$1,040M were calculated in the white paper. Please provide a calculation of the total per-well royalties using the fifteen percent discount rate that OXY used for its own internal analysis.  
From BP, all documents supporting Mr. Policky's testimony to the House Finance Committee that BP's rate of return varies 2-3% higher than OXY's rate of return, and an EXCEL-type spreadsheet (on disk to speed analysis) of the calculation of the rate of return.
5. BP's 1995-1997 Business Plan dated 9/30/94 and any other BP or OXY Business Plan related to Schrader Bluff pool development.
6. Provide BP and OXY's actual marine transportation cost per barrel and a description of the differences between BP and OXY's transportation costs.

Mr. John Morgan  
BP Exploration (Alaska) Inc.  
February 9, 1996

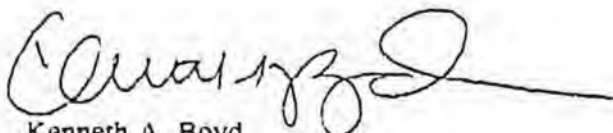
Mr. Edward J. Behm  
OXY USA Inc.

7. The Arthur D. Little study cited in the BP/OXY white paper states that a TAPS owner has a \$1.00/bbl advantage over a non-TAPS owner. If either BP or OXY does not agree with that proposition please provide the relevant calculation along with the supporting documentation.

8. Mr. Policky testified on February 8, 1996, to the House Finance Committee that currently the Milne Point Unit CPF is running at capacity at 25MBD with Kuparuk production; that they intend to add 40MBD in the next few weeks for Kuparuk production; that they intend to add 10MBD capacity in 1997 for Cascade/Kuparuk production; and that they would then need to add an additional 15MBD capacity for Schrader Bluff production. Please provide a detailed schedule of production versus capacity for the MPU CPF specifically explaining the capacity schedule as it relates to the production curve for the 230 well development scenario that shows a peak of 45MBD. If not detailed above already, please provide a detailed capital investment schedule for the two Schrader Bluff pool development scenarios.

If you wish the Division to maintain any of the information submitted as confidential, please mark each page "confidential," submit such information in a sealed envelope separate from non-confidential information, and provide a statement describing the authority under which the Division may maintain the information confidential. If you have any questions about the analyses or data to be provided, please address them in writing to Kevin Banks, Petroleum Economist, Division of Oil and Gas, 3601 C Street, Suite 1380, Anchorage, Alaska, 99503-5948. Because we are dealing with the Legislature in a public forum, any communications should be made in writing.

Very truly yours,



Kenneth A. Boyd  
Director, Division of Oil and Gas

cc: Commissioner John Shively, Department of Natural Resources  
Representative Mark Hanley, Co-Chair, House Finance Committee,  
Alaska State Legislature  
Jim Palmer, BP Exploration (Alaska) Inc.

WILLIAM M.  
**MERCER**  
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Handout  
2/14/96

February 13, 1996

Mr. Robert F. Stalnaker  
Director of Retirement & Benefits  
State of Alaska  
Department of Administration  
Division of Retirement & Benefits  
P.O. Box 110203  
Juneau, AK 99811-0203

**Re: National Guard and Naval Militia Retirement System**

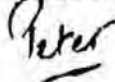
Dear Bob:

In the June 30, 1994 actuarial valuation report for the System we recommended a reduction in the 25-year amortization period for unfunded liabilities following the introduction of a lump sum retirement benefit option. This was due to the fact that a large proportion of retirees have recently elected lump sums at retirement. We suggested reducing the period to 10 years, which is the approximate average expected future service to retirement for the current active membership. The valuation disclosed that this reduction in the amortization period would increase the past service cost by about \$600,000, resulting in a total contribution of approximately \$2.6 million for fiscal years 1997 and 1998.

The valuation disclosed that the funding ratio as of June 30, 1994 was 17.2%. In other words, 17.2% of the present value of accumulated benefits is funded by assets. Given the low level of the funding ratio, we recommend that the contribution of \$2.6 million be implemented as soon as possible. The sooner this accelerated funding is implemented, the sooner we can expect the funding ratio to return to levels which are financially sound.

Please do not hesitate to call, Bob, if you have any questions or comments.

Kind regards,



Peter L. Godfrey, FIA, ASA, EA, MAAA  
Principal

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AKA.96/FTAL0213.FLG

c: Mr. Brian R. McGee

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