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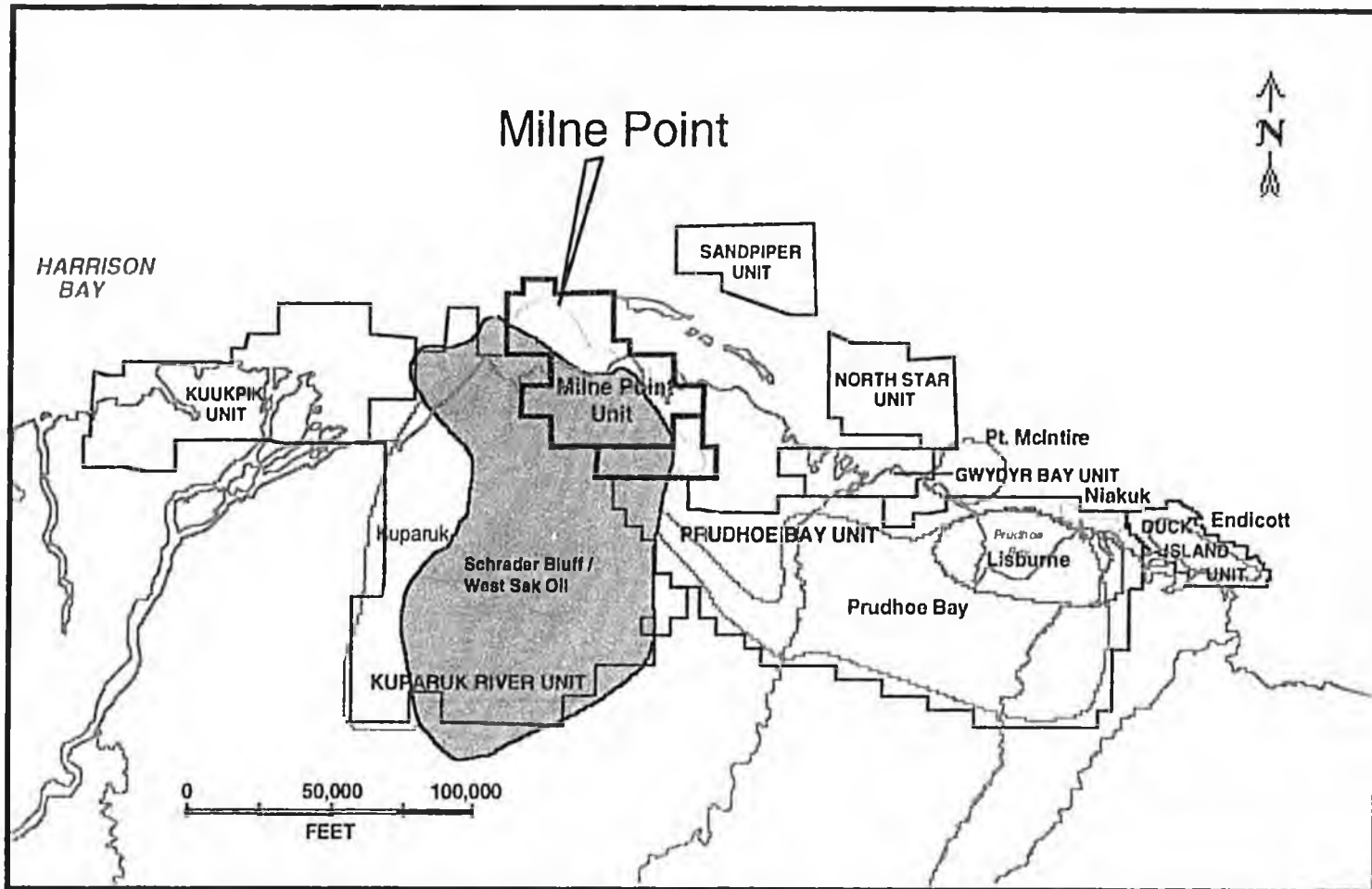
**325**

# **Heavy Oil Potential at Milne Point**

**Presentation by BP Exploration (Alaska) Inc  
before the House Natural Resources Committee**

**January 26, 1996**

# North Slope Fields



# Schrader Bluff Heavy Oil Development

- 
- The map illustrates the Schrader Bluff Heavy Oil Development, divided into three main sections: KRU (Krusenkrantz Unit), CFP (Central Field Pad), and PBU (Pilot Borehole Unit). The development is categorized into three stages: 'Development at Acquisition' (light gray), 'Development in Progress' (dark gray), and 'Future Development' (white). Existing pads are marked with solid black squares, while future pads are marked with squares containing a grid pattern. The map also shows a coastline to the west and a wellbore extending south from the PBU section.
- Development at Acquisition
  - Development in Progress
  - Future Development
  - Existing Pad
  - Future Pads

# 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**

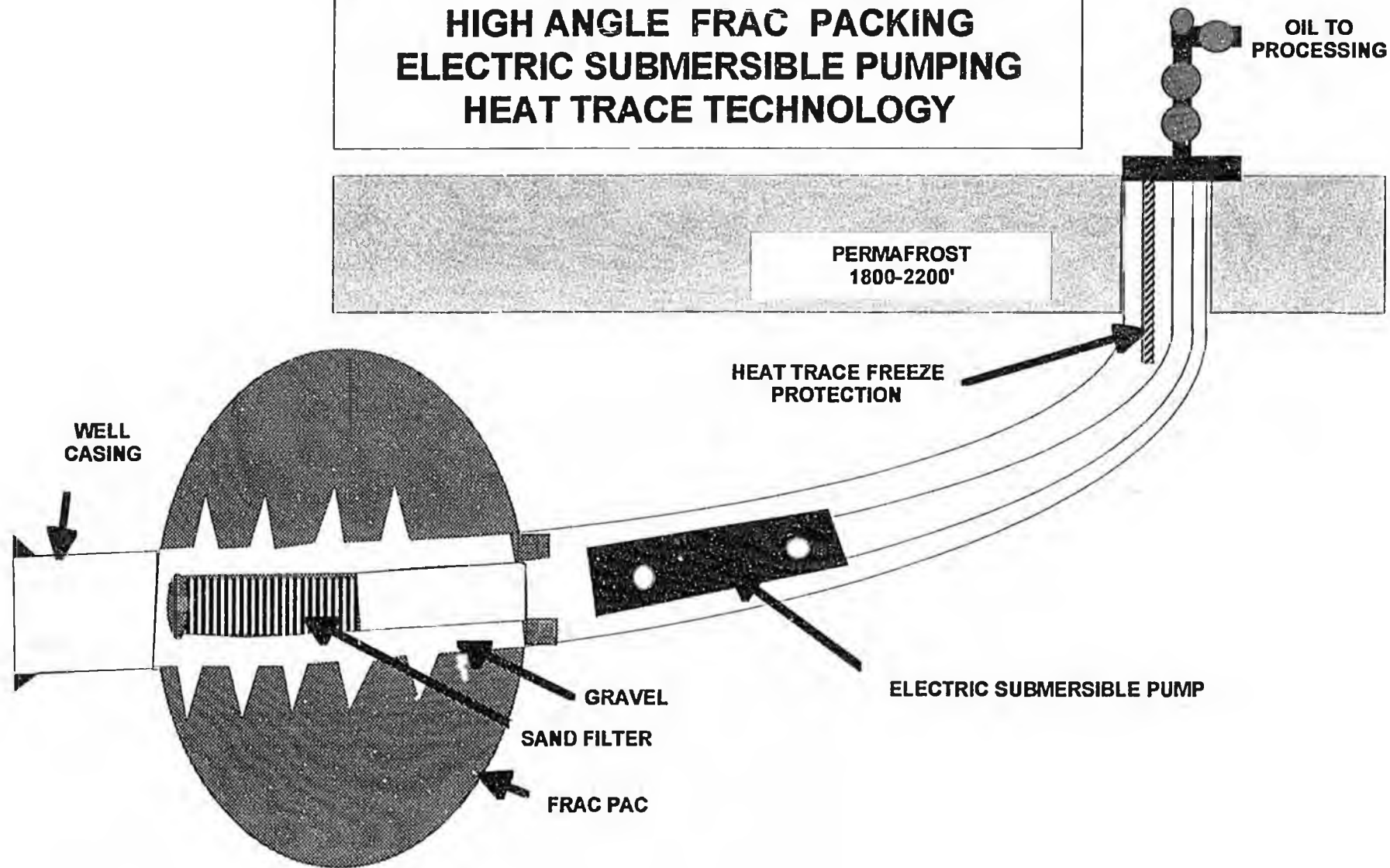
- Six wells drilled; completions in progress; not on production
- Three wells recompleted and on production
- Reservoir and facility technical studies initiated

- **Results**

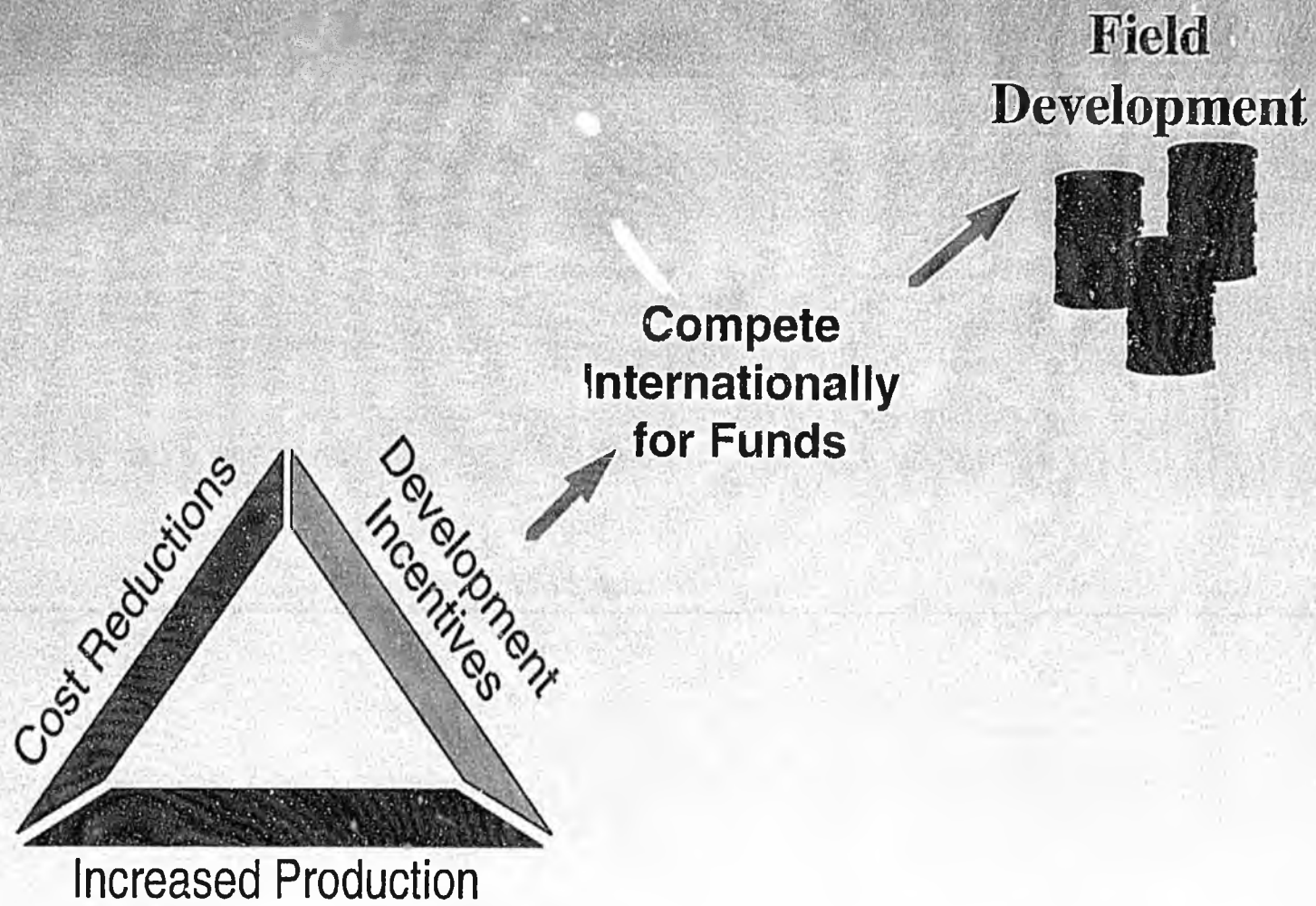
- Drilling cost reduction demonstrated
- Completion cost remains problematic
- Improved submersible pump life realized
- Well performance and technical study results not yet available

**SCHRADER BLUFF TECHNOLOGY:**

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



# Schrader Bluff Challenges



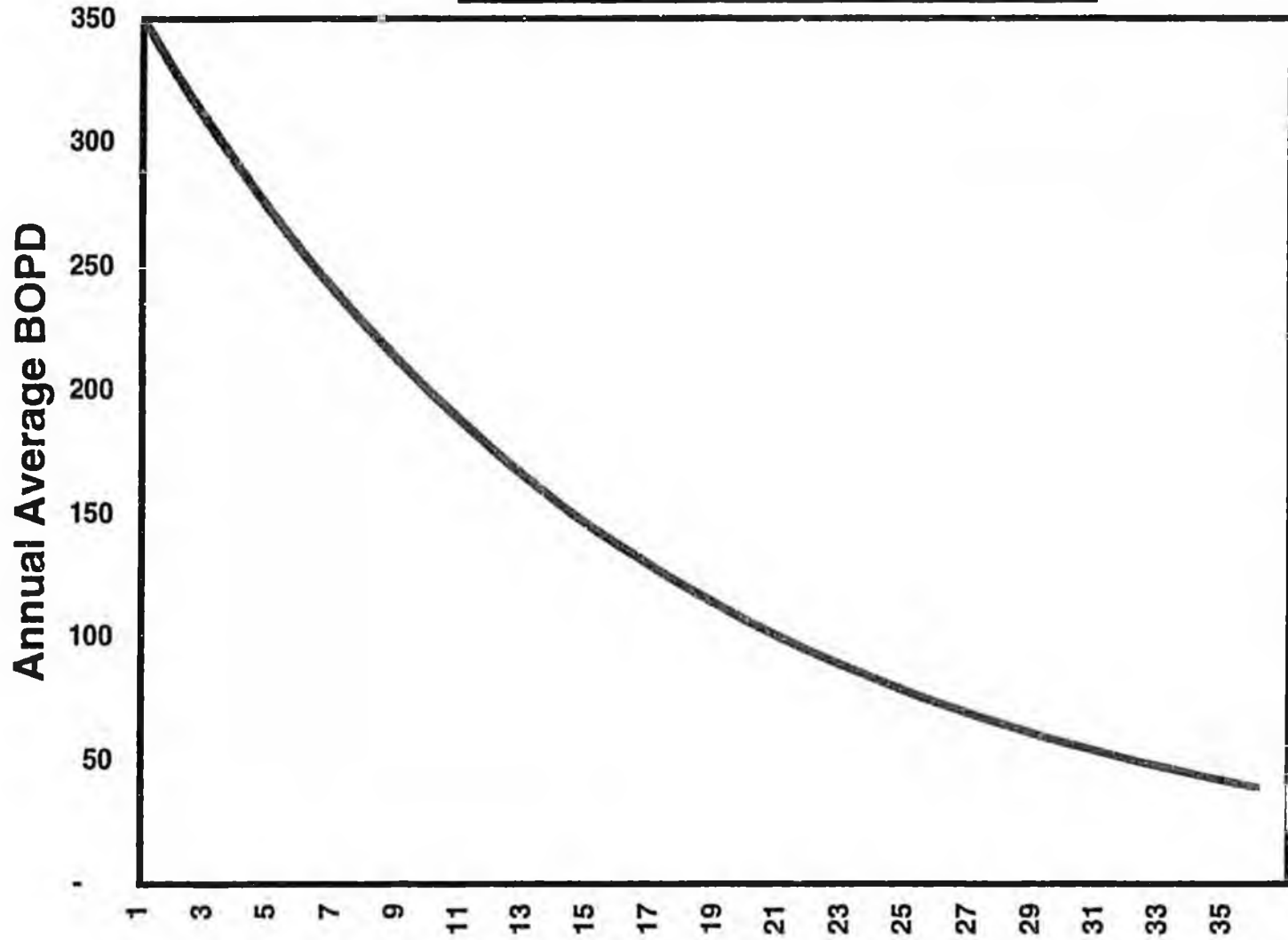
## **The “Prize” at Schrader Bluff**

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

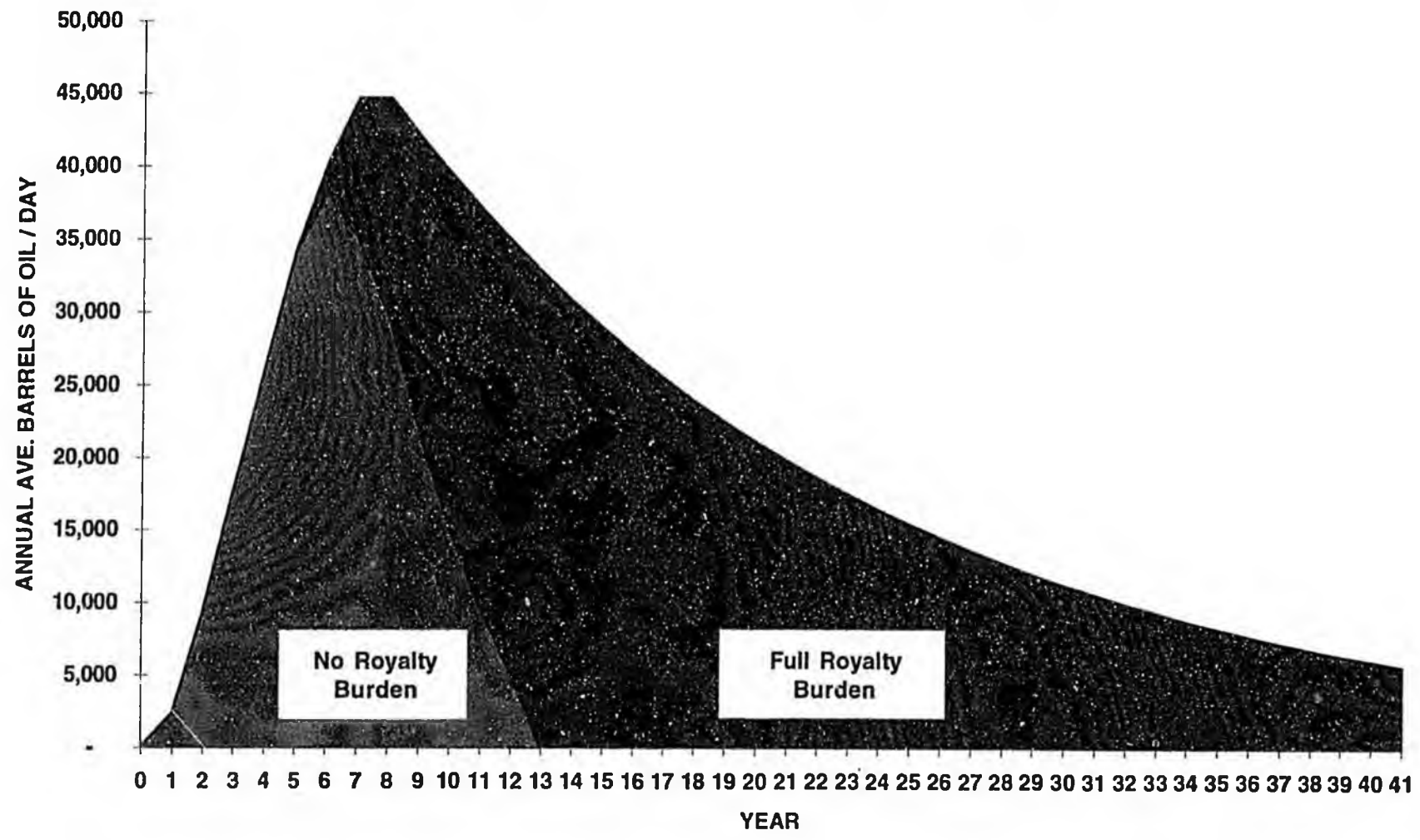
## **Heavy Oil Royalty Holiday (HB-325) Impact on Schrader Bluff Project**

- **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)**

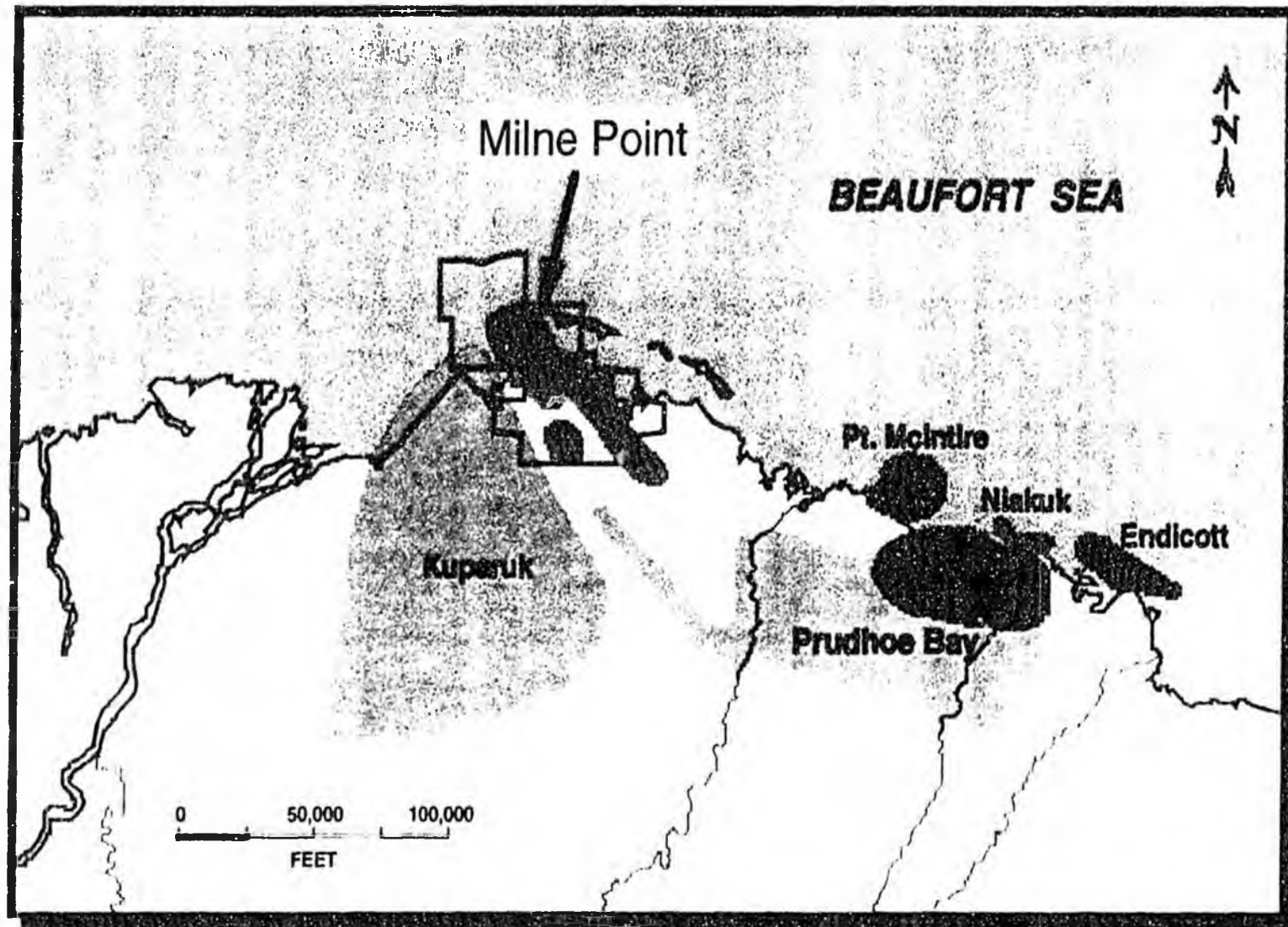


## **The “Risk” of Project Development Delay**

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

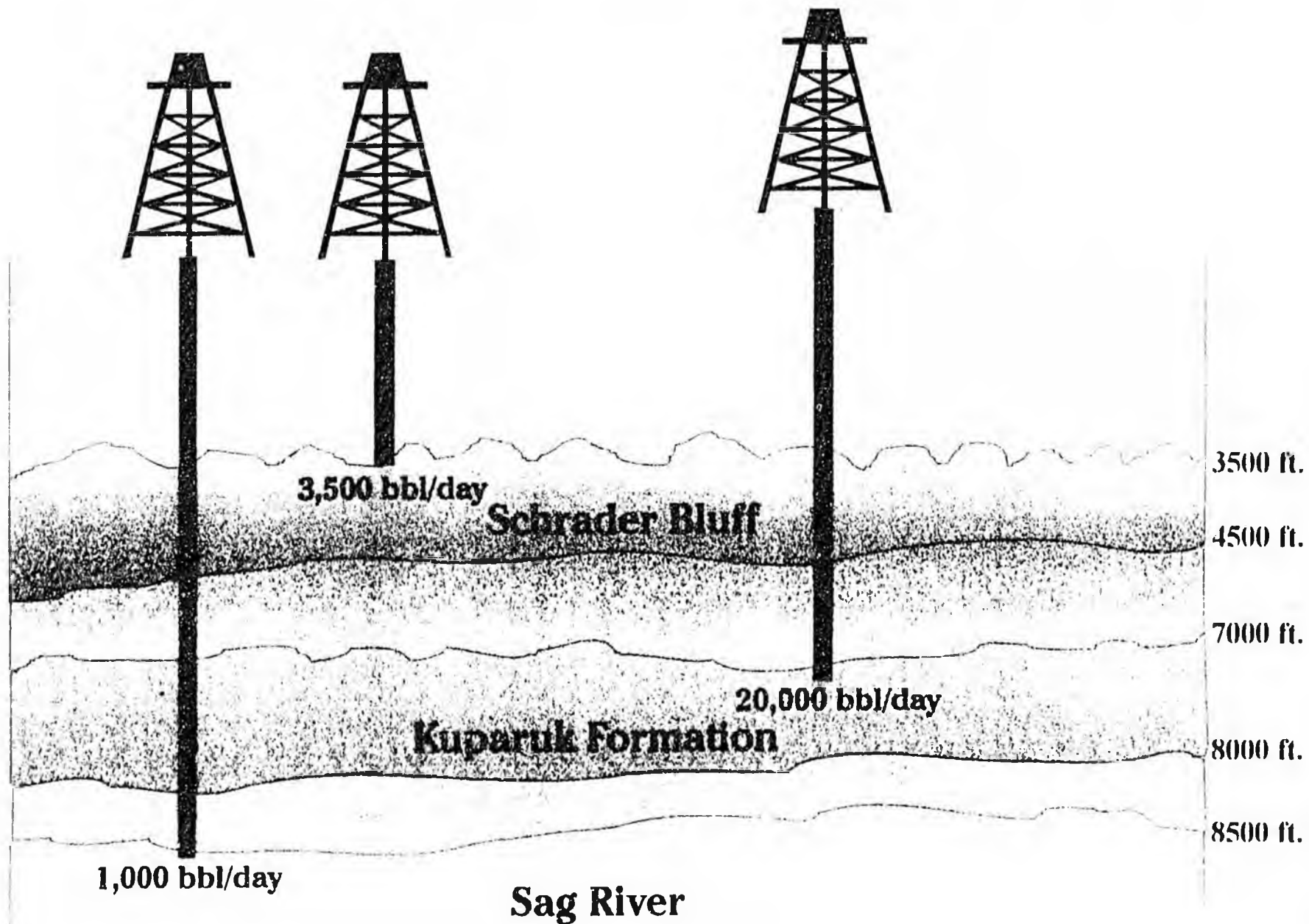
# **WHO IS OCCIDENTAL OIL AND GAS CORPORATION?**

- *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*



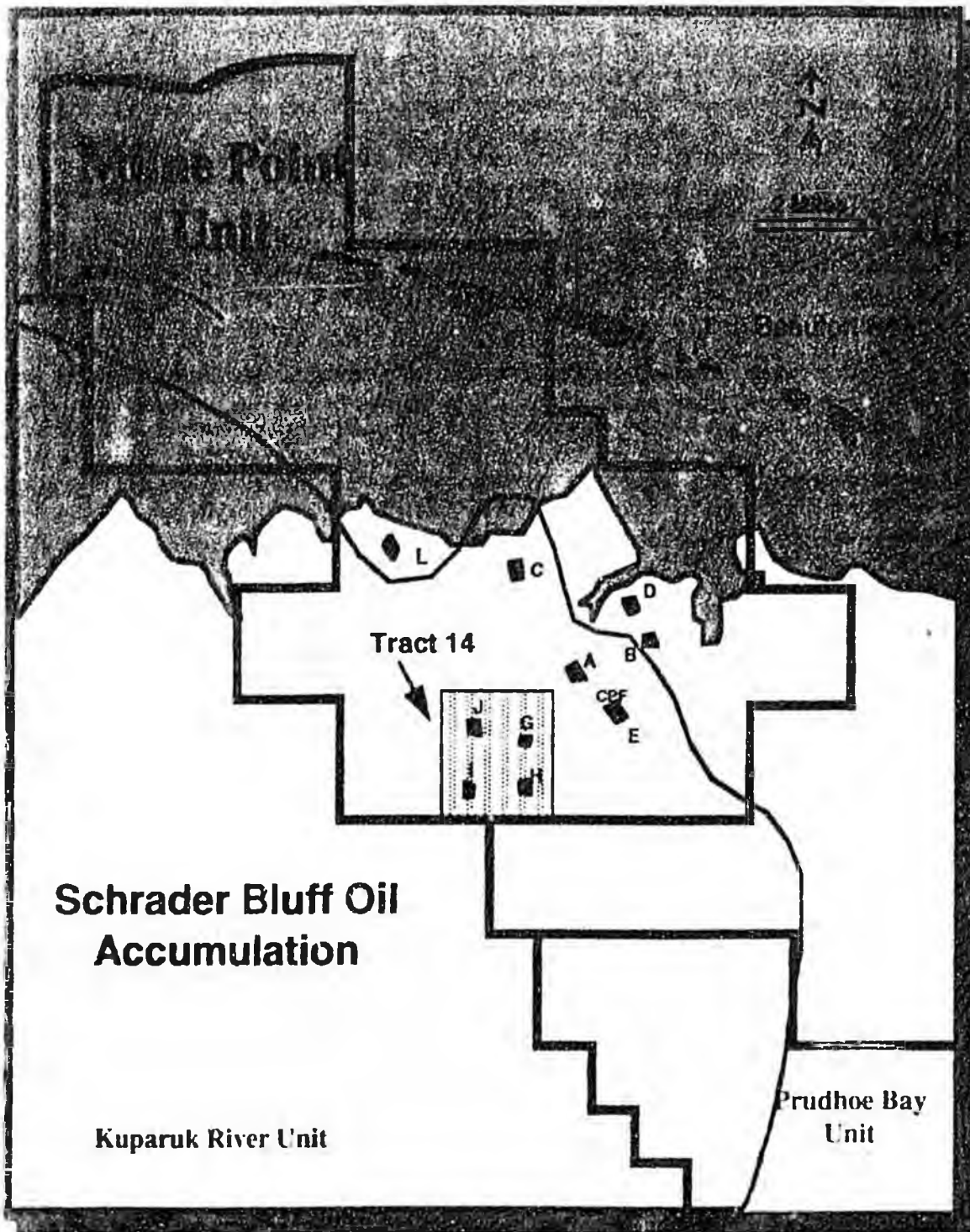
North Slope Fields and Milne Unit Outline

# Occidental and BP produce oil from three formations at MPU



# 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 Oil Accumulation

# Previous Heavy Oil Experience

Conoco/Tract 1 :

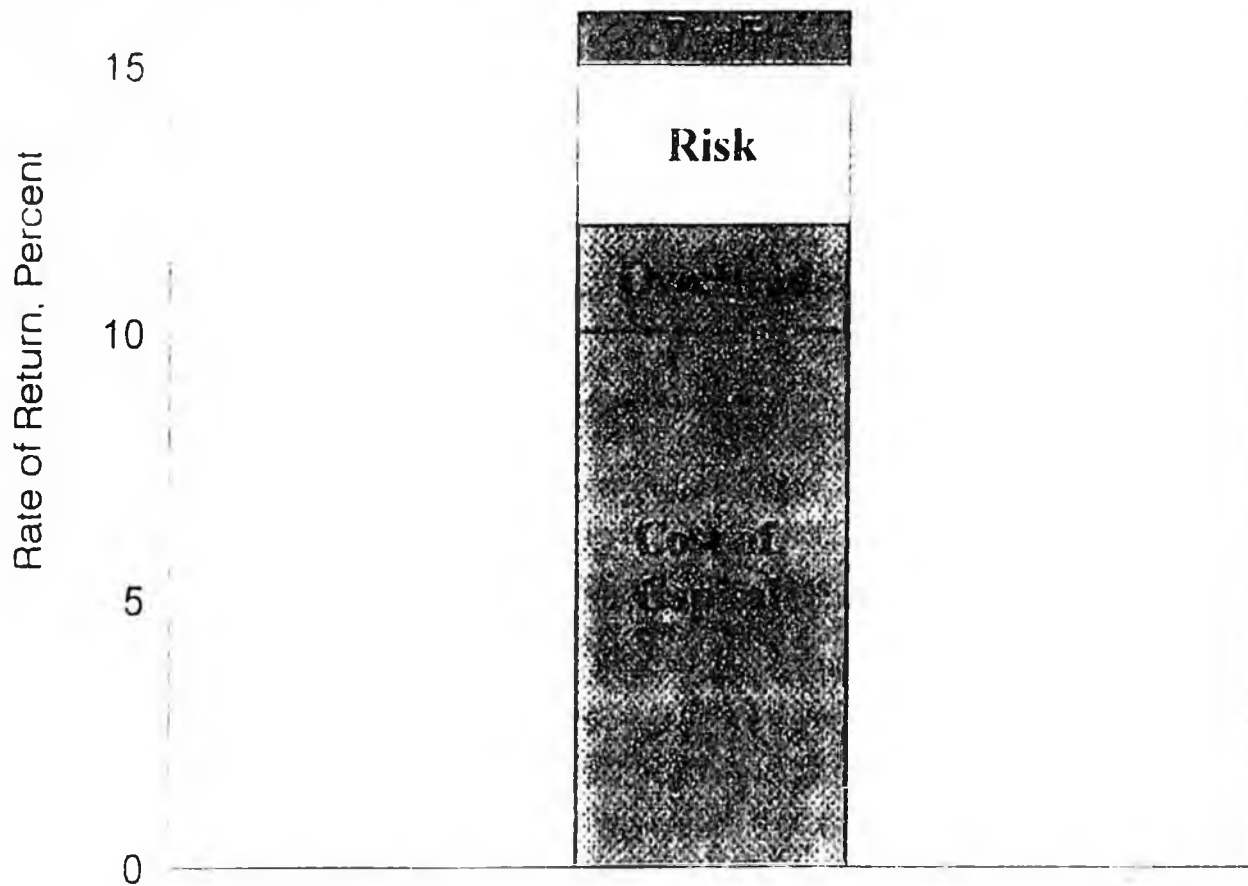
- *Spent a minimum of \$126 Million on 22 wells, pads, etc.*
- *Average producing rate = 275 BOPD per well*
- *Expected Recovery = 13.5 Million Barrels*
- *Total Investment = \$9.30/BBL*

▪ *Uneconomical*

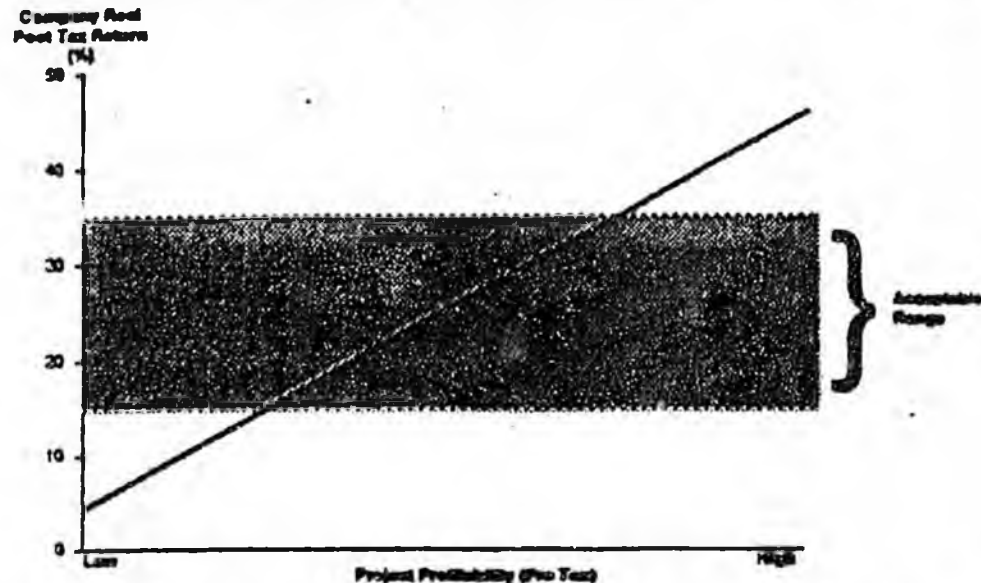
Source: SPE 30289, "Milne Point Schrader Bluff: Finding the Keys to Two Billion Barrels", 6/95. Reserves determined from decline curve analysis.

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

"Marginal fields have low levels of gross project value: Developments require a RoR ~15%" (pg 122, Arthur D. Little Study)



## Conventional fiscal systems are fiscally inefficient



Arthur D Little

1980/1981

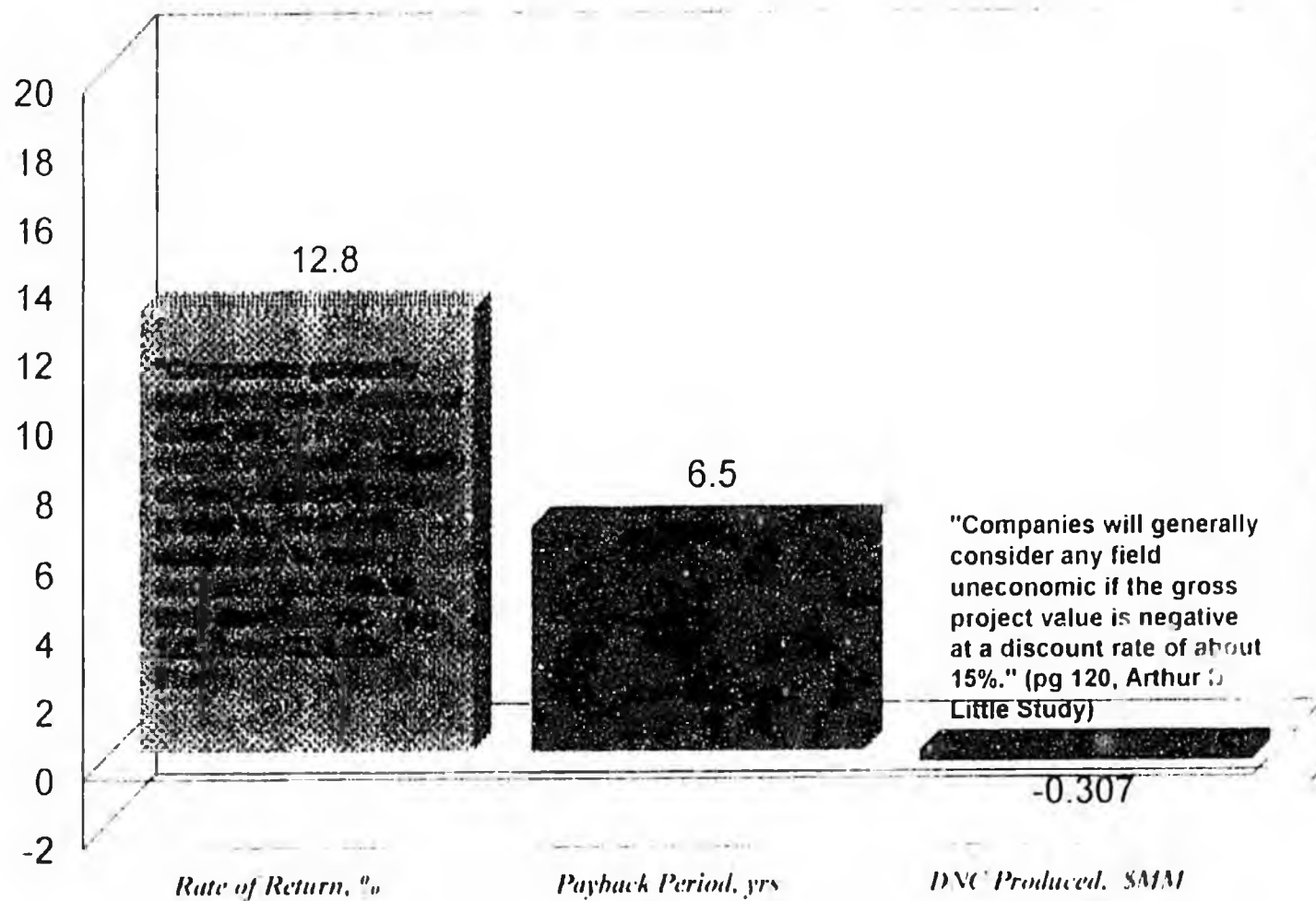
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## Conventional fiscal systems are fiscally inefficient:

- 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 1980 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)

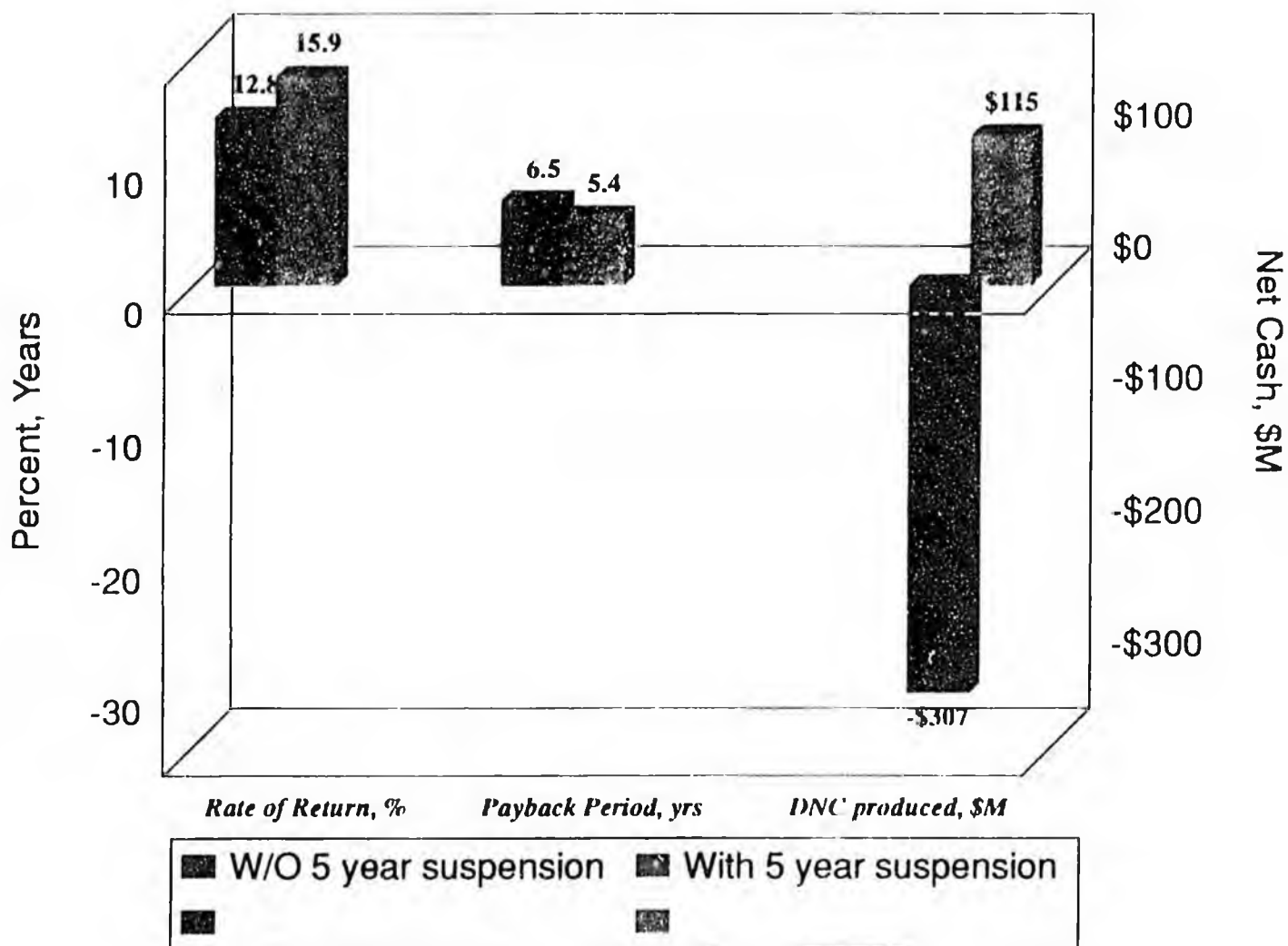
shallow wells (for life of project)

discovery wells (first 12 years)

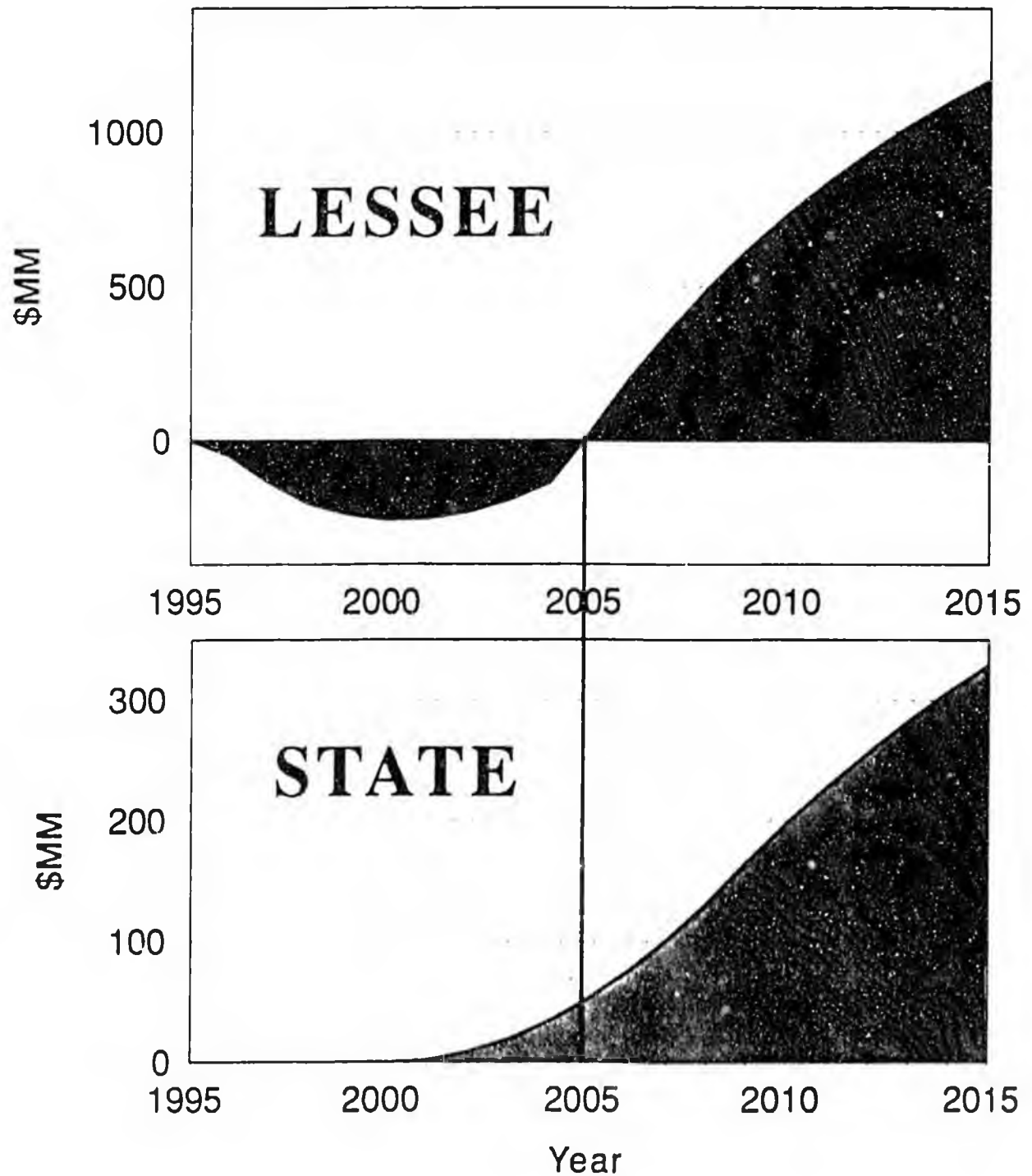
## Arkansas

discovery wells (first 5 years)

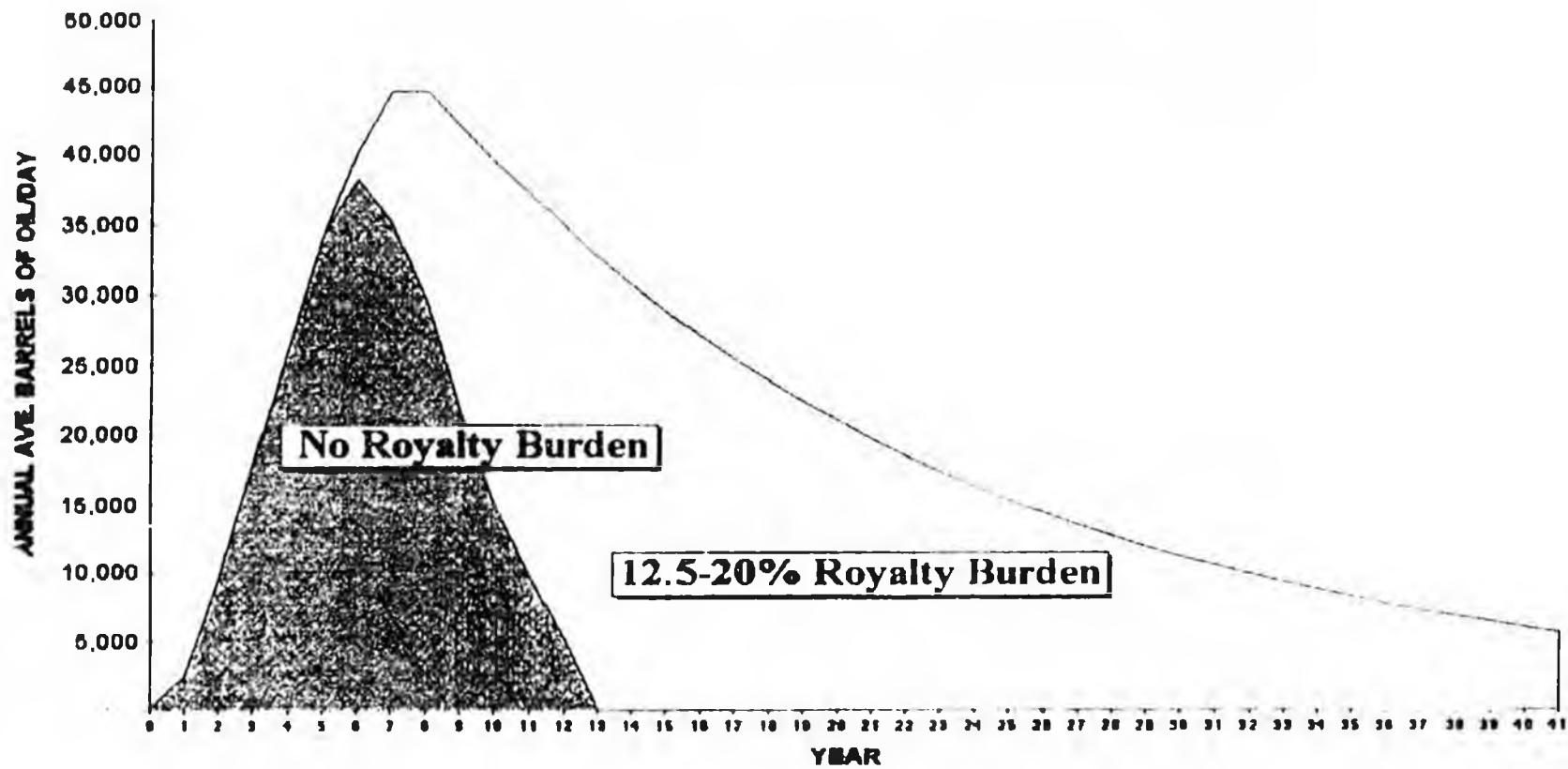
# The Effect of Royalty Suspension on Schrader Bluff Economics



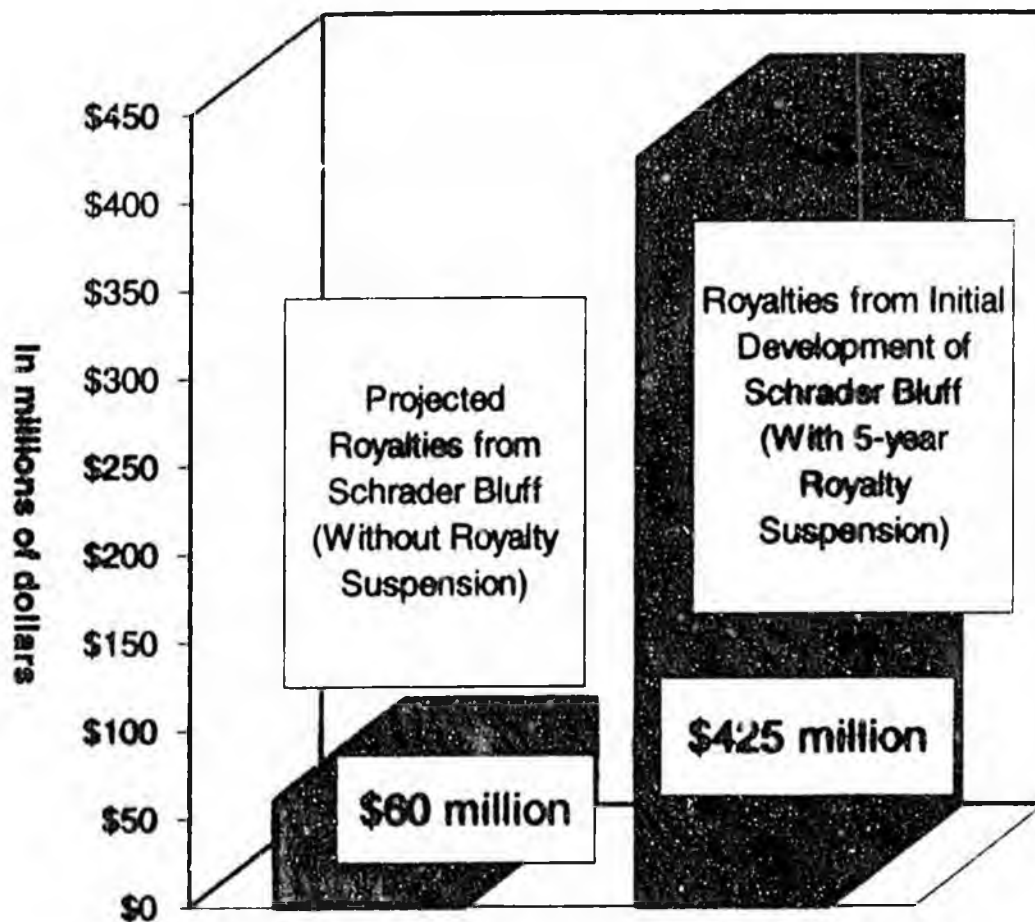
# Cumulative Cash Flows From Full Development

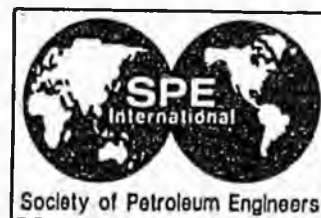


# ADDITIONAL PRODUCTION FROM HEAVY OIL BY DEVELOPMENT YEAR



## Two Paths for Schrader Bluff





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

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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, roads 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 deposits redistributed, for the most part, below wave base. Bioturbation, and burrows are common in some intervals whereas, others display finely 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 correlative across the North Slope than the thinner, more discontinuous "N" interval. The "O" sands thickness varies between 10 to 35 ft 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 rbb/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 recompletions 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.

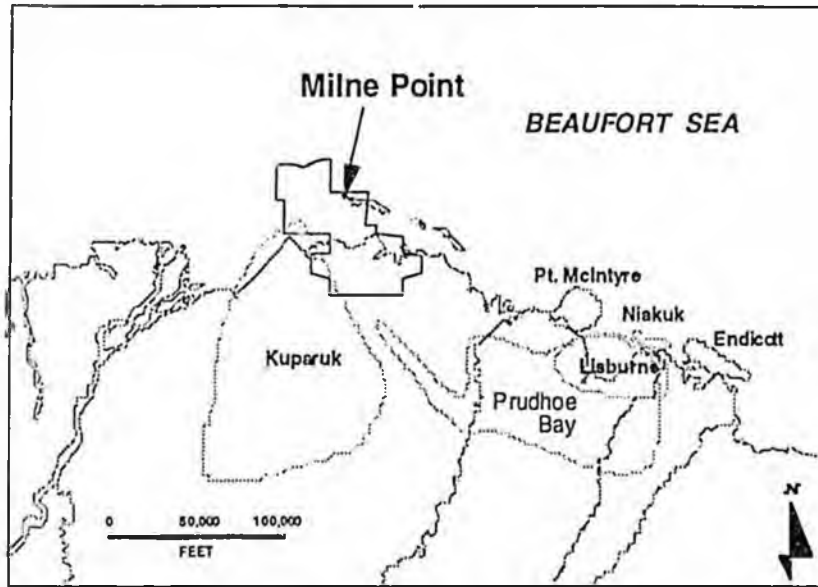


Figure 1 - Map of the North Slope of Alaska

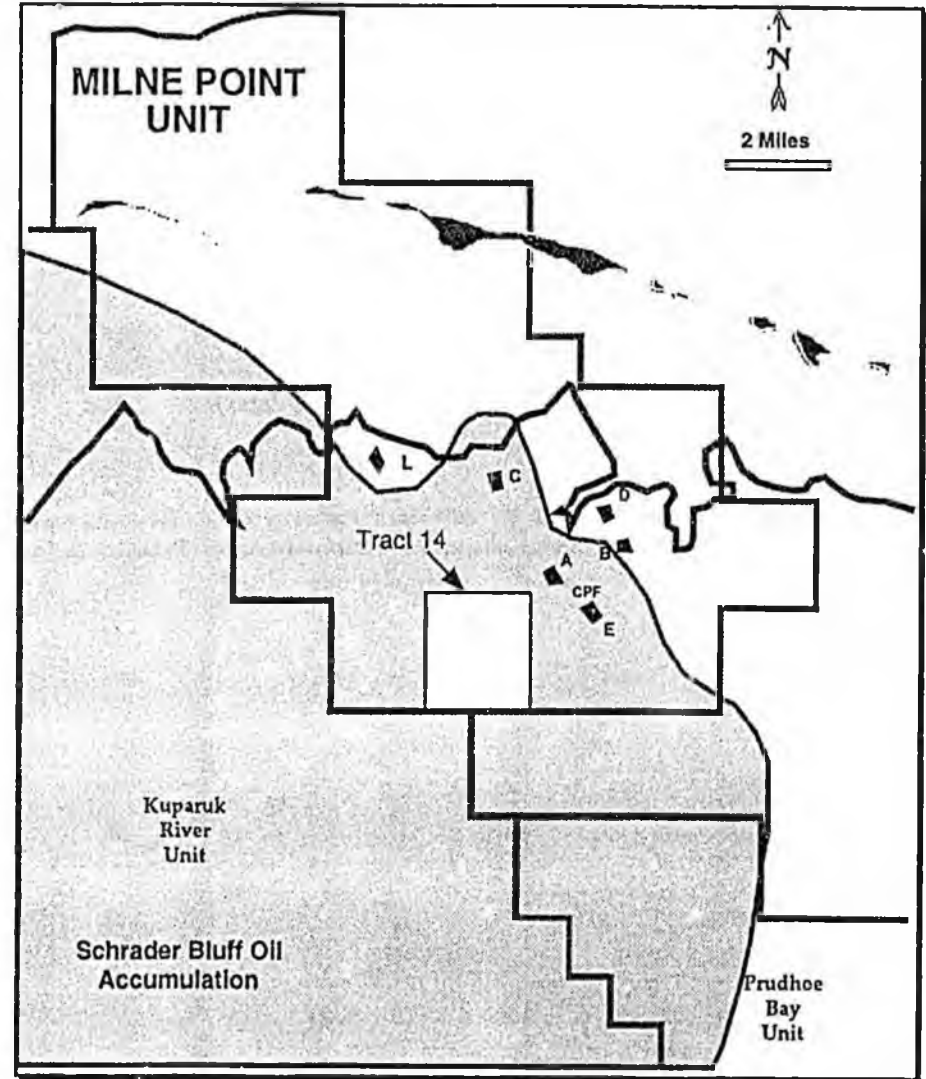


Figure 2 - Schrader Bluff Oil Accumulation

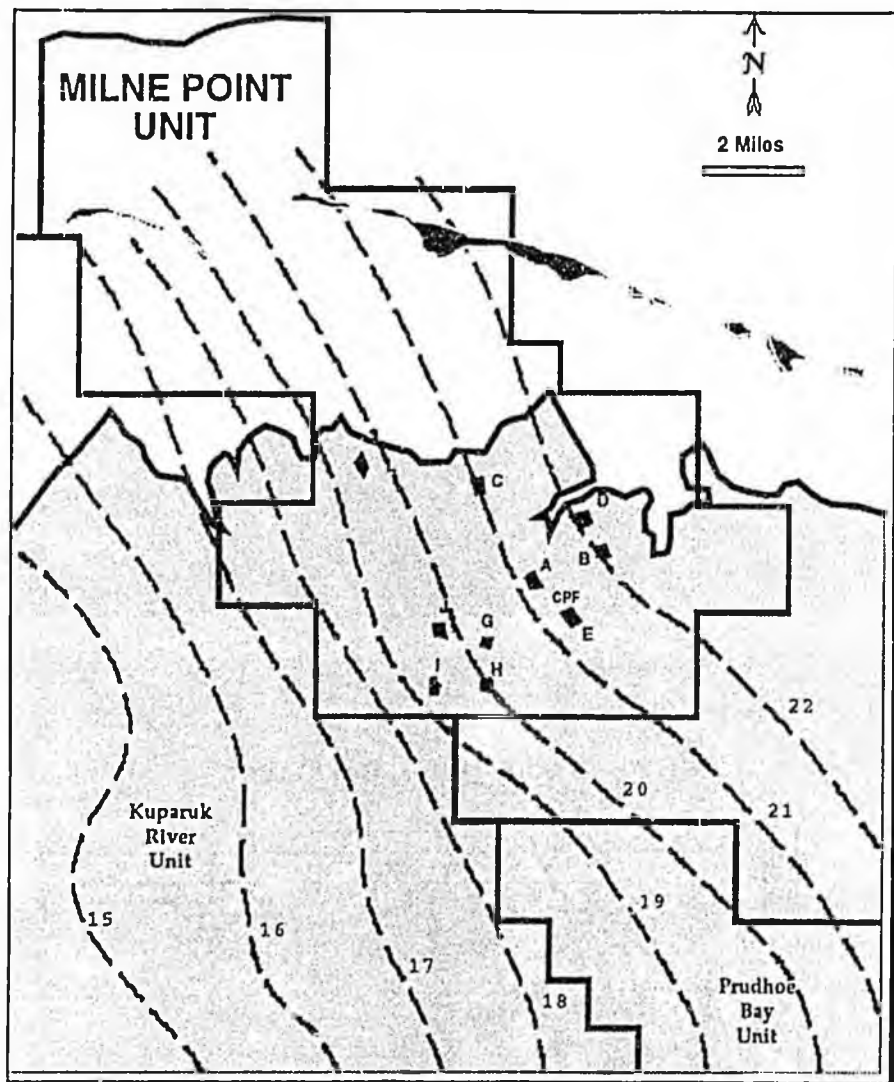


Figure 3 - Schrader Bluff API Gravity Map

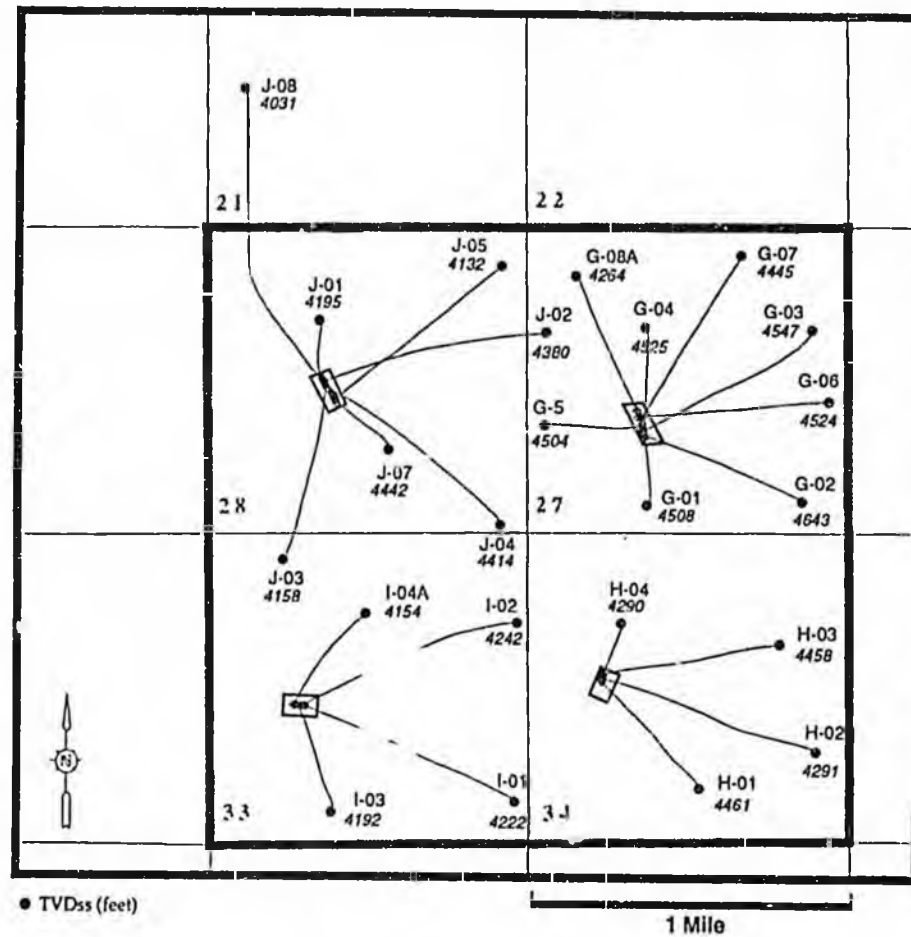


Figure 4 - Tract 14 Well Location Map

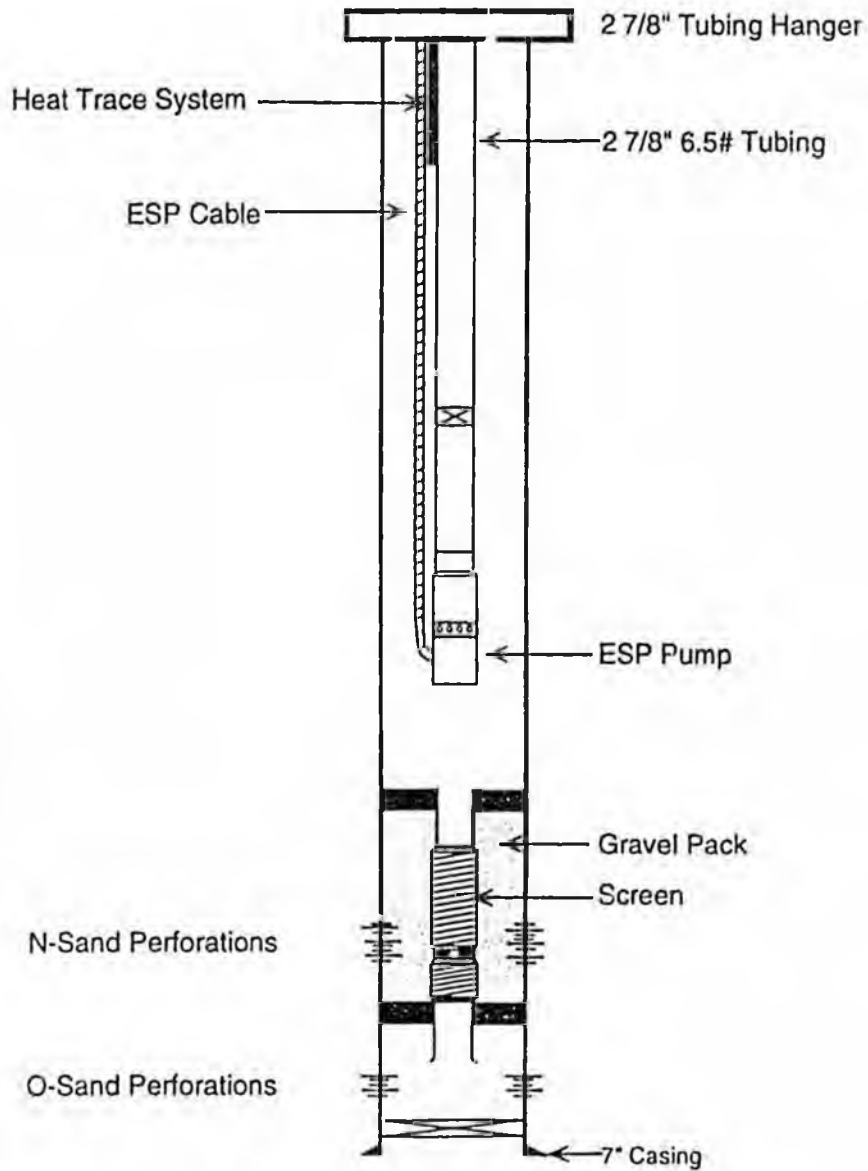


Figure 5 - Generic Schrader Bluff Completion

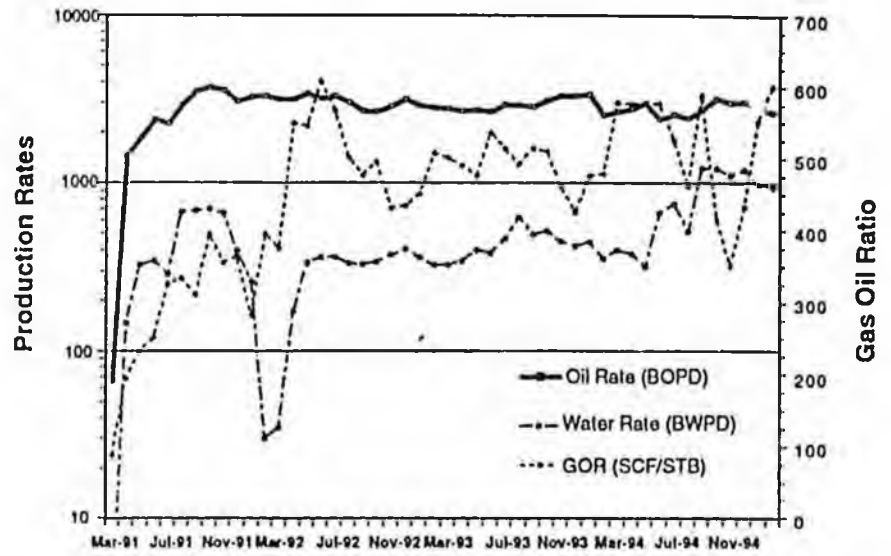


Figure 6 - Monthly Average Production History

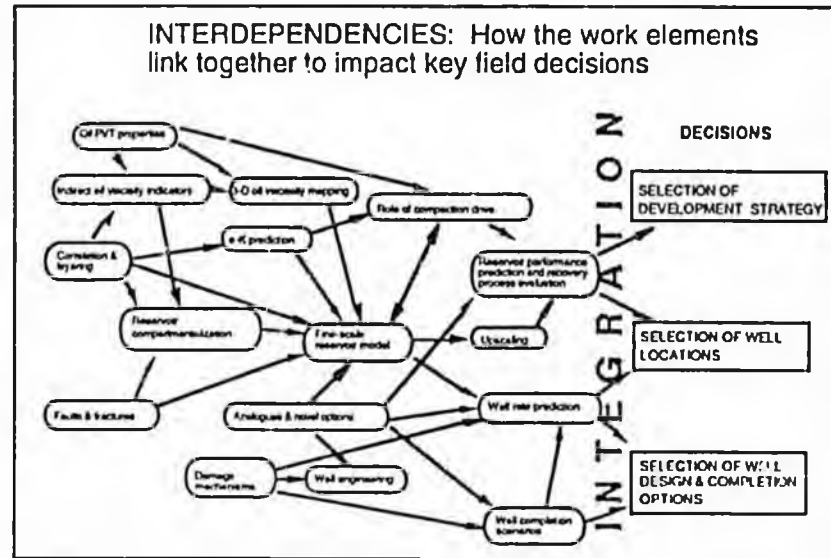


Figure 7 - Work Program Interdependencies

HOUSE COMMITTEE REPORT

(7)

Date Referred: April 28, 1995

FURTHER REFERRALS:

Resources  
Finance

Date of Committee Action: 11/23/96

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>Scott Dgan</i>	✓			
<i>Nancy Koko</i>	✓			
<i>Elizabeth Williams</i>	X			
<i>Henry...</i>			✓	
<i>Robert...</i>	X			
<i>and...</i>		X		
<i>Bette Davis by Shirley...</i>	X			

CHAIR'S SIGNATURE

*Nancy Koko*

1-23-96

# Alaska State Legislature

WHILE IN SESSION:  
CAPITOL BUILDING  
JUNEAU, ALASKA 99801-1100  
(907) 465-4011  
(907) 465-4116 FAX

INTERIM ADDRESS:  
710 WEST 9TH AVENUE  
ANCHORAGE, ALASKA 99501  
(907) 266-0100  
(907) 266-0174 FAX



CO-CHAIR, RESOURCE 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

### 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.

# FISCAL NOTE

**STATE OF ALASKA**  
**1996 LEGISLATIVE SESSION**

**BILL NO. HB325**

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

**Expenditures/Revenues (Thousands of Dollars)**

OPERATING EXPENDITURES	FY97	FY98	FY99	FY00	FY01	FY02
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
<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>

<b>CAPITAL EXPENDITURES</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>
-----------------------------	------------	------------	------------	------------	------------	------------

<b>CHANGE IN REVENUES (1004)</b>	<b>(228.0/well)</b>	<b>(228.0/well)</b>	<b>(228.0/well)</b>	<b>(228.0/well)</b>	<b>(228.0/well)</b>	<b>(228.0/well)</b>
----------------------------------	---------------------	---------------------	---------------------	---------------------	---------------------	---------------------

**FUND SOURCE (Thousands of Dollars)**

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
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: \$ none

**POSITIONS**

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

**ANALYSIS: (Attach a separate page if necessary)**

It is not possible at this time to accurately predict the number of new wells that will be drilled that will qualify for the proposed royalty reduction. Nor is it possible to accurately predict the timing of the drilling of any of these new wells. For each new well that is drilled, if it produces at a rate of 500 barrels per day and oil is valued for royalty purposes at \$10 per barrel, then the annual royalty reduction will be \$228,000 for each of the first five years of well life. Assuming that the well produces at the 500 b/d rate for five years and oil prices stay flat, the total royalty reduction would amount to \$1.14 million per well – close to the cost to drill the well. For a new demonstration project equal in size and scope to the existing Milne Point Schrader Bluff heavy oil project, the royalty reduction would range from \$1.5 million per year at current well rates to \$3.7 million per year at well rates of 500 b/d/well. Long term production behavior also is unknown for these wells. It is suspected that the wells will produce at a fairly constant rate for at least five years then production decline will begin. Behavior of the Milne Point Schrader Bluff wells is being analyzed to see if any production trends are evident to date.

Prepared by: Ken Boyd, Director Phone: 269-8800  
 Division: Oil & Gas Date: 18-Jan-96  
 Approved by Commissioner: \_\_\_\_\_ Date: 18-Jan-96  
 Agency: Natural Resources

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

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: *[Signature]*  
 Agency: Department of Revenue

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

PREPARER TO PROVIDE ALL DISTRIBUTION COPIES TO GOVERNOR'S LEGISLATIVE OFFICE  
 For further distribution information call the Governor's Legislative Office

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.

# 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*

# 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)

# BUSINESS

1995 - NOV. 17

ANCHORAGE DAILY NEWS

SECTION E

ACE

rief

NYSE

18.48  
-2.01

SDAQ

44.48  
-2.63

average rose  
g in on the  
ry's 30-year  
or \$9.06 per  
ield finished  
d commodity

## Oil royalty breaks get hearing

### Legislators, producers back incentives for tough fields

By KIM FARARO  
Daily News business reporter

The Legislature is expected to take up a bill next year that would guarantee oil companies significant financial breaks at the North Slope's giant, but difficult-to-produce, West Sak field.

Rep. Joe Green, R-Anchorage, the bill's sponsor, said it would allow oil companies to produce 500 barrels per day, per well, for each well's first five years without paying the royalty Alaska is due as landowner.

Because most or all West

Sak wells are likely to produce less than 500 barrels daily, the bill could slash Alaska's royalty take over the life of the oil field. The state Department of Revenue says the state could collect tens of millions of dollars less than if the field were developed without a financial incentive.

At a House Oil and Gas Committee hearing this week, Green said that's a small price to pay to get the field on line. Without the incentive, he said, West Sak won't be economic to develop, and the state will lose out on the royalty generated

after wells produce for five years.

The financial incentive is just one of many that have been considered by the Legislature and governor over the last several months in efforts to revive the state's ailing oil industry.

Green, a former Arco Alaska Inc. engineer, said he proposed the bill during this year's legislative session because he didn't think a new royalty-reduction law, passed this year, would provide enough incentive for companies to develop West Sak.

That law allows the natural resources commissioner to drop royalties at new marginal fields, though not below 5 percent. A 5 percent royalty means the state owns 5 percent of the oil, or one out of every 20 barrels produced. The royalty on most state land is 12.5 percent, or one of every eight barrels.

To earn the royalty break, companies must convince the commissioner that the break is needed to make the field worth developing.

Please see Page E-4, OIL

## OIL: Legislative panel reviews royalty bill

Continued from Page E-1

Green says the biggest problem with that new law is that the reductions are discretionary, not mandatory.

His bill would provide breaks not only to West Sak, but to other North Slope fields that produce heavy oil, meaning thick, hard-to-pump crude. Those fields would include Schrader Bluff, as well as other producing fields if new wells there produce heavy oil.

BP and Occidental Oil, Schrader Bluff's owners, are pushing the legislation. The companies say the royalty break will help them develop the field, a relatively small heavy-oil field considered easier to pump than most of West Sak. The companies are producing some crude from Schrader Bluff, but they say devel-

oping the rest of the field with existing technology is uneconomic.

Arco owns much of West Sak. At this week's committee hearing, Arco lobbyist George Findling said Arco probably won't be sure for a year or two whether it might need even more of a break than a zero royalty for five years.

West Sak contains an estimated 20 billion barrels of crude, but Arco says it would expect to recover just a half-billion barrels because the oil is so difficult — and expensive — to pump. By comparison, Alaska's largest field, Prudhoe Bay, contains 25 billion barrels and is expected to produce 13 billion barrels.

The main difficulty with West Sak is that it's much closer to the earth's surface, making the oil colder and thicker than Prud-

hoe's. Pumping Prudhoe's oil is like sucking soda through a straw; producing from West Sak is like trying to suck molasses.

Worse yet for West Sak, the rock that holds the crude crumbles easily, closing off the tiny openings that allow oil to flow toward wells.

Schrader Bluff suffers from the same difficulties, but it's deeper than West Sak, so the crude isn't as cold or thick.

Rep. Norman Rokeberg, R-Anchorage, chairman of the oil and gas committee, said Wednesday he likes the bill because he thinks it will spark development of Schrader Bluff, where he hopes BP and Occidental will pioneer techniques that will make West Sak easier to pump.

"(West Sak) is the real big enchilada, if you will," said Rokeberg.

the ...  
fore the Civil War.

The closing has left Bethlehem workers feeling betrayed. They helped bail out the company with concessions in the 1980s, only to see it spend the money on other plants out of town and out of state.

The hot-metal men and the big-beam shapers are the latest to fall to cutbacks that have shrunk the Bethlehem plant in northeastern Pennsylvania from 31,000 workers at its post-war heyday in the 1960s to 1,200 today. The skeleton crew will continue non-steelmaking operations, including a coke furnace and a combine mill that rolls unfinished steel.

Bethlehem was once America's No. 2 steelmaker, back when 85 percent of all goods manufactured in the United States had some steel in them and 40 percent of the nation's work force owed its wages, directly or indirectly, to steel.

Chances are almost any major bridge you cross or any skyscraper you see has some Beth steel in it. Metal forged here went into landmarks like the Golden Gate and George Washington bridges, helped erect missile silos.

But over the past 30 years, American giants like Bethlehem and U.S. Steel have been caught in what industry expert Paul Tiffany called "the twin pincers of foreign steel and the minimills."

"Bethlehem had to get out of the 'hot end,'" Tiffany said. Making iron and steel "is the most labor-intensive part of the industry, and Bethlehem was far out of the running."

For instance, Bethlehem sells the massive I-beams

## Postcards puts animated tour guide to work

age is 50, so it's a grandchild product. It has to be marketed a little bit different."

The creation of Monty and the video really began last Christmas, Hardesty said. That's when the company began researching basic animation of the 1940s and started maneuvering through the process of giving Monty a look and a voice.

Actor and announcer Larry Robinson of Brooklyn Heights, N.Y., gives

as he reviewed the tape in the company's production room. "He's kind of the Rex Harrison of cartoons."

Hardesty is gambling a sizable investment that viewers will appreciate a moose with the mannerisms of the late "My Fair Lady" actor.

"This is the most expensive tape we have produced," Hardesty said. The company has more than a dozen tapes on the market. With a budget of roughly \$200,000, the Monty video

combination packages. The plan is to sell the product to the 80,000 to 100,000 tourists who come through the firm's doors each summer.

"They are all looking for something for their grandchildren," Tougas said. "People always come up to the counter and ask if you have anything for kids."

The bulk of the company's clients are 50 or older, he said.

"It hits that grandparent market," Tougas said. "I told him (Hardesty) to go ahead and send me 200 of

## 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.

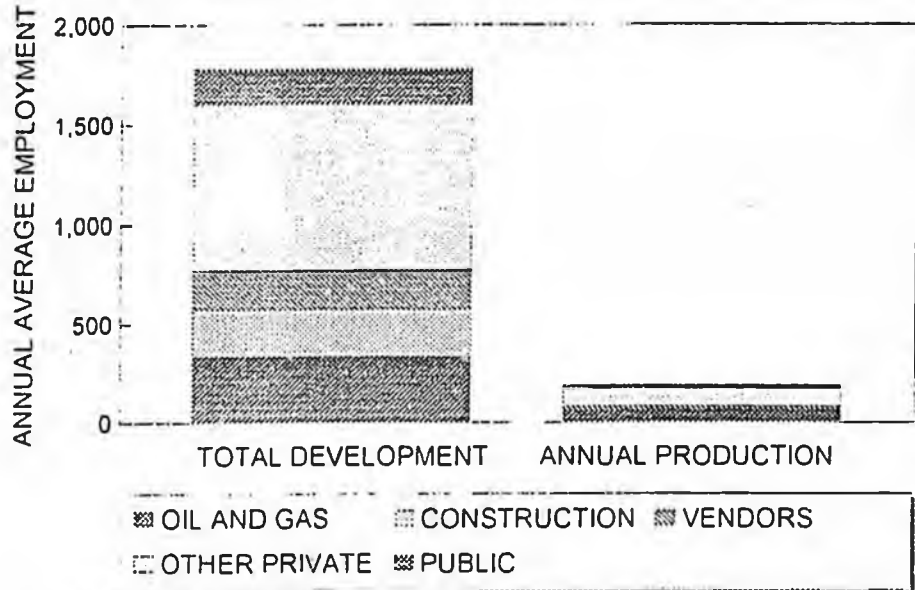
The costs to state government from marginal field development consist of management costs such as environmental monitoring, tax auditing, etc., and more importantly the costs of providing services for the families of the new workers both onsite and in Alaska's urban centers. These costs can be divided 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.

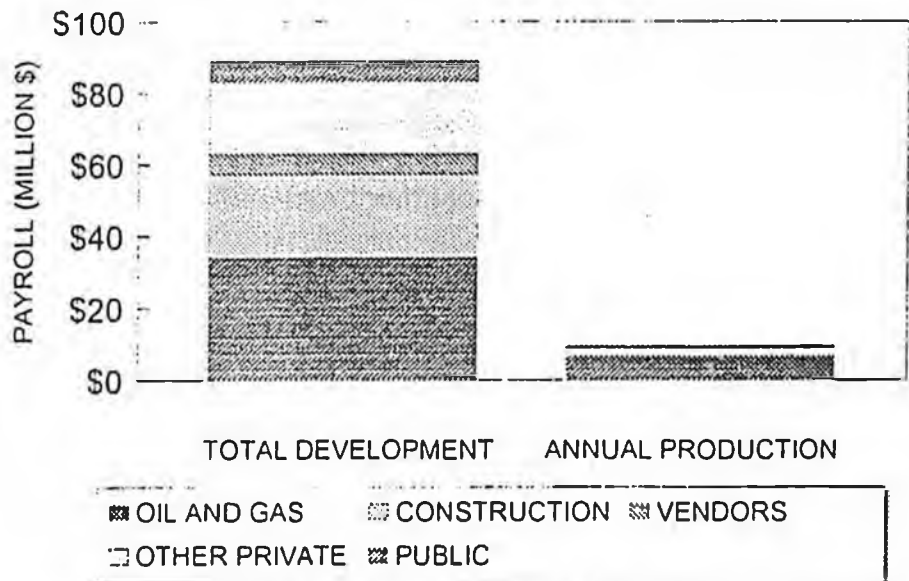
Finally, Figure 5B compares the state's natural resource revenues from various resources with the state's resource management expenditures for those same natural resources. The marginal oil field is the only case where resource management costs are covered by the revenues generated, and the substantial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

**FIGURE 1A. MARGINAL FIELD ECONOMIC EFFECT  
RESIDENT EMPLOYMENT**



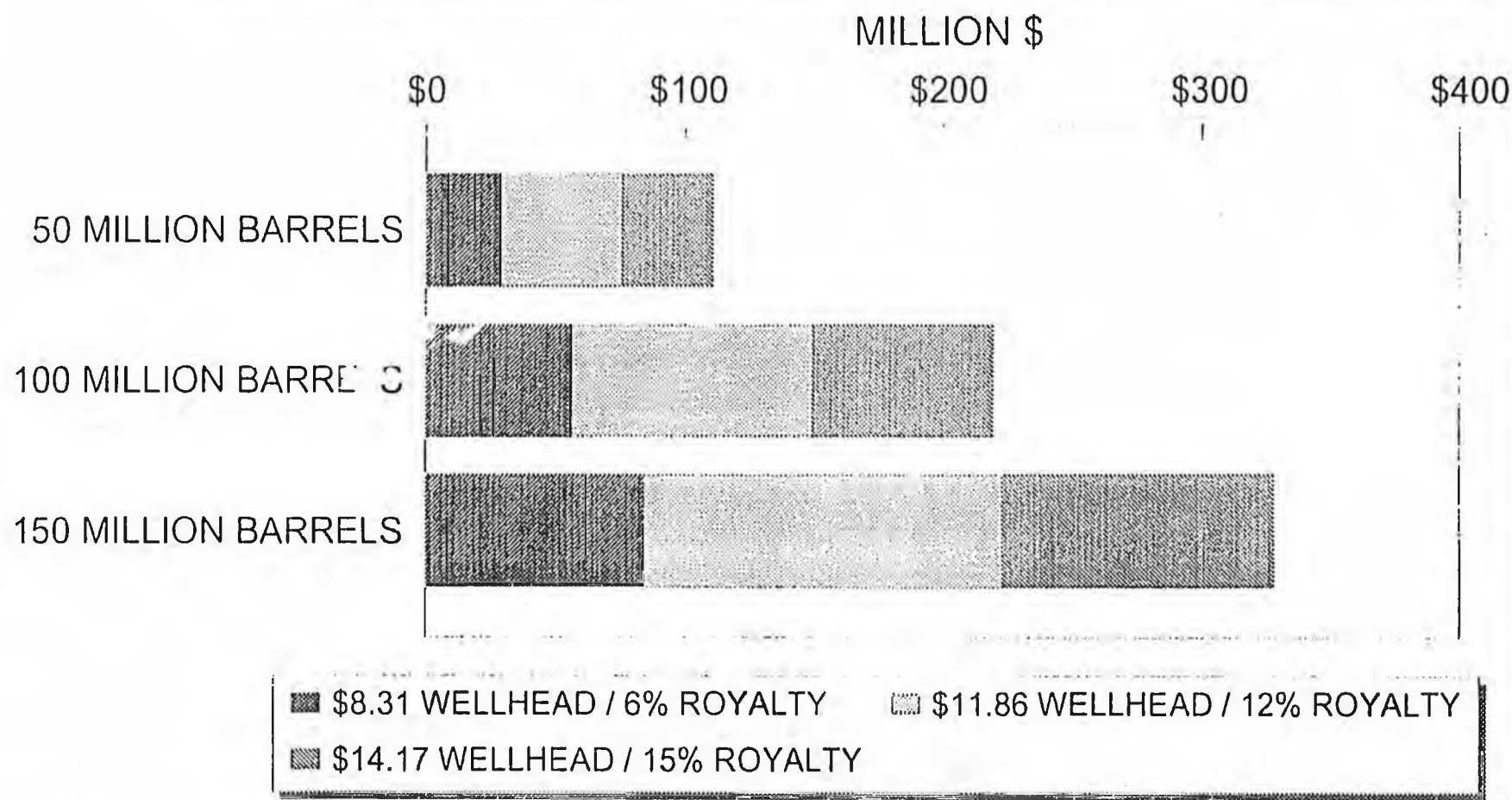
DEVELOPMENT EMPLOYMENT SPREAD OVER SEVERAL YEARS

**FIGURE 1B. MARGINAL FIELD ECONOMIC EFFECT:  
RESIDENT PAYROLL**



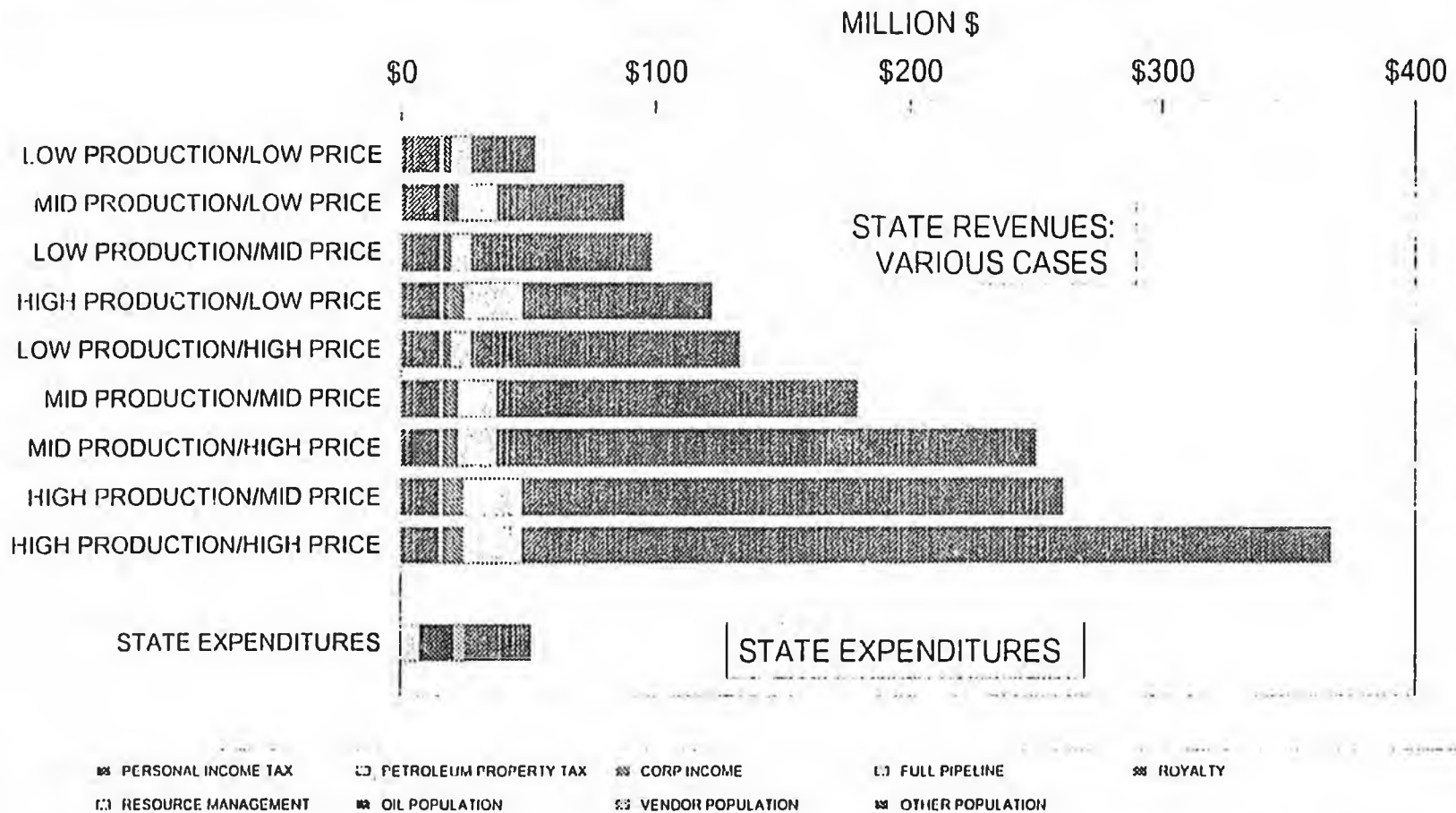
DEVELOPMENT EMPLOYMENT SPREAD OVER SEVERAL YEARS

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



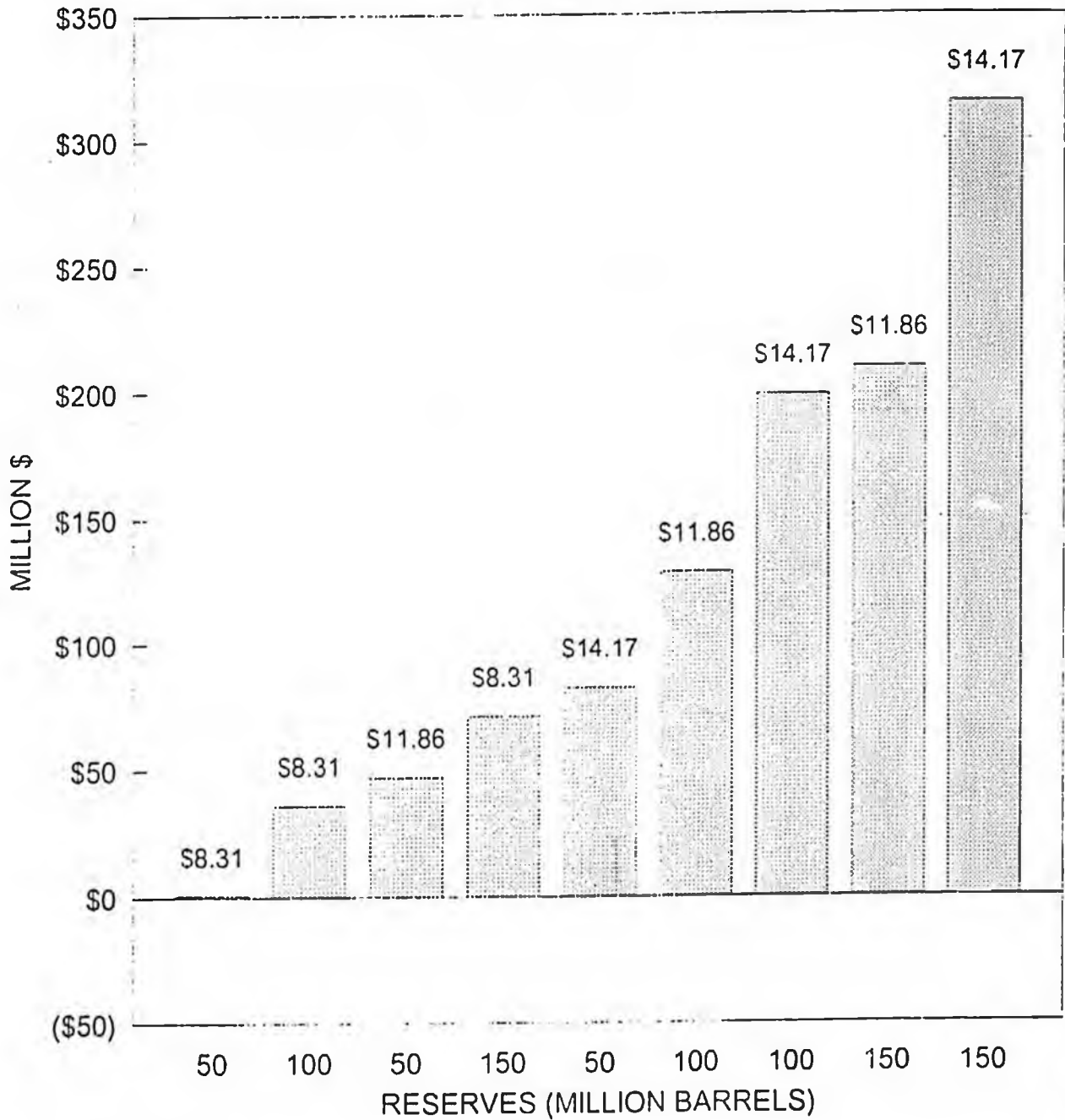
REVENUES OVER THE LIFE OF THE FIELD

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



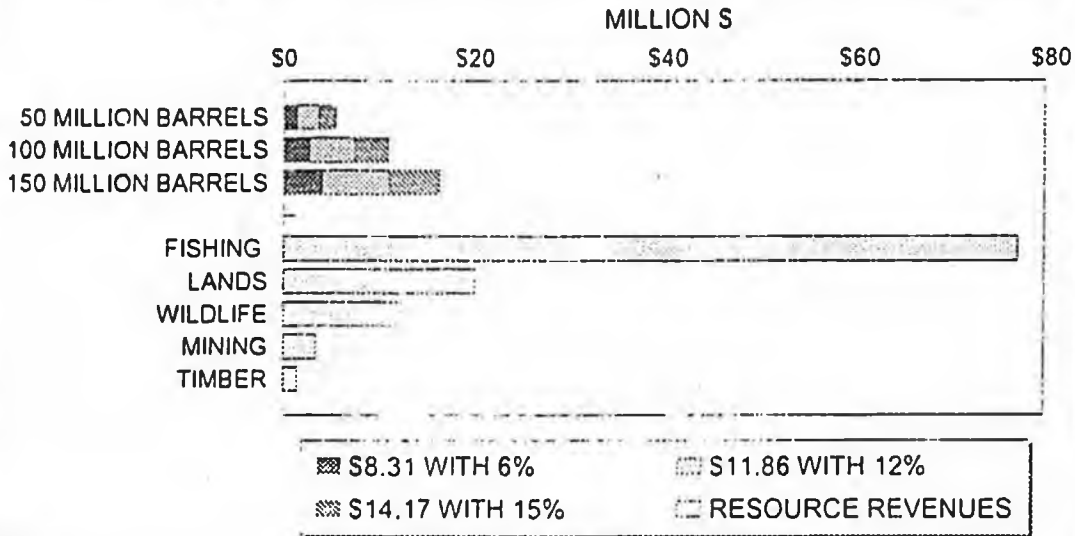
# FIGURE 4. STATE REVENUE "DIVIDEND"

VARIATION IN RESERVES, PRICE, AND ROYALTY RATE



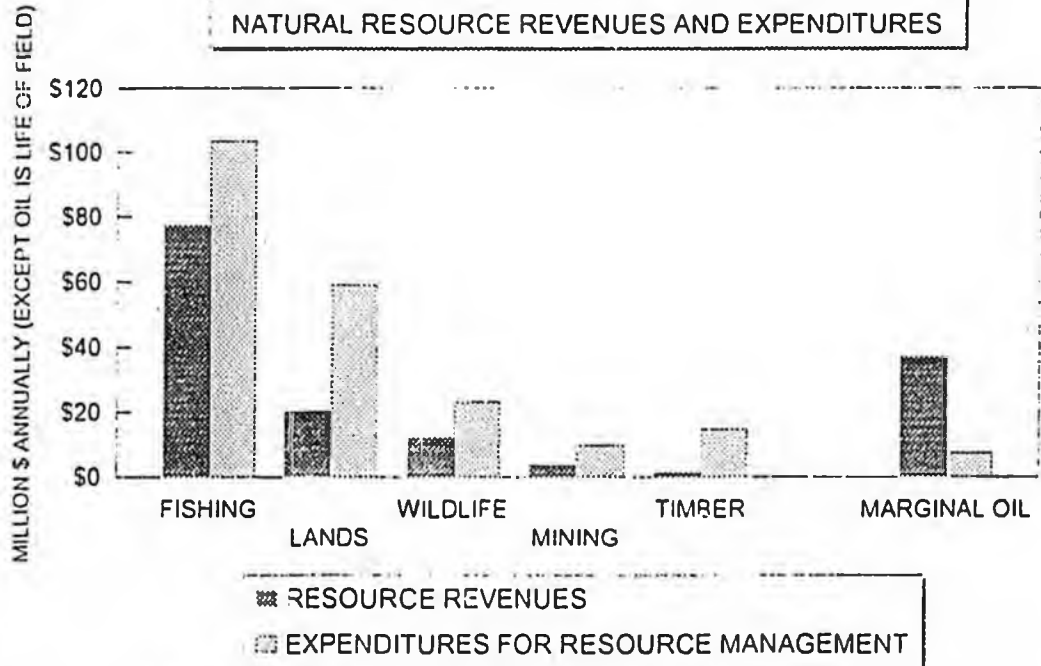
REVENUES IN EXCESS OF AMOUNT NEEDED  
TO PROVIDE NEW PUBLIC SERVICES

**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

## 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  
Malemutes 18-

SPORTS • C-1



# Daily News-Miner

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

Gina Macphee/News Miner

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

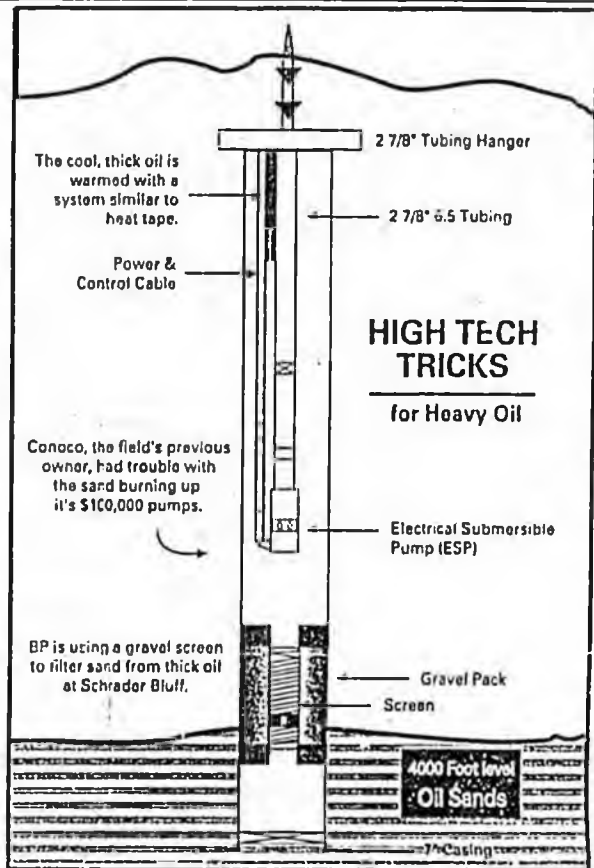
expert Bill Van Dyke. "It's a lot of oil and there is some production, but the individual wells just don't produce at a very high rate."

### 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

Dave Branner/News Miner

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 arctic 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 Mark Air 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 output 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 retrieval, 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 in 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-delimited 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 look for Bantam publishing. "If that doesn't work, I just might get a whole collection of aloha shirts and shorts and wai' around 'em 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 wheeling she and Gov. Tony Knowles wade 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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## ARCO plans to pump West Sak

ARCO Alaska, Inc., may begin producing oil from the giant West Sak field as early as 1997, but most of the 20 billion barrels of crude in the formation will never be produced because of the oil's thickness.

West Sak is the giant, hard-to-produce North Slope oil field that ARCO has been studying for years, trying to develop the technology necessary to profitably pump the field. The company's president, Ken Thompson, said ARCO intends to bring on the field one section at a time, starting with the easiest in 1997, if ongoing studies show that such an approach is sound.

ARCO plans to spend about \$10 million in 1996 on West Sak studies and expects to make a final decision late in the year. At that point the company should know how much crude it can produce from its first phase of development and how many wells it will need.

Speaking before the RDC Thursday breakfast forum last month, Thompson said phased development would allow ARCO to learn how best to pump the field and to test theories on how drilling technologies will work at West Sak. The field lies above the large Kuparuk formation. Because it is closer to the surface, West Sak's oil is thick as molasses, which poses much greater development and production challenges compared to warmer, thinner oil deeper underground. Thinner the oil, the easier it is to pump to the earth's surface.

Although West Sak rivals Prudhoe Bay in size, it's considered a marginal field since most of the oil is non-recoverable. Moreover, West Sak is likely to be a slow producer because of the characteristics of its crude. The field is unlikely to generate large revenues to the state's treasury, but will create jobs.

# 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 techn-

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.



## 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:

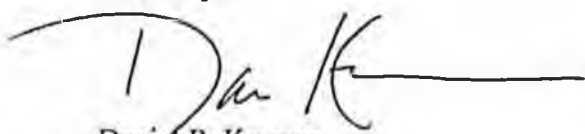
The California Independent Petroleum Association (CIPA) wishes to express its strong support for HB 325, provided that Congress lifts the ban on the export of Alaskan North Slope crude oil which appears likely to happen soon. CIPA represents over 550 production, exploration and service companies operating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



Daniel P. Kramer  
Executive Director

1/31/96

AMENDMENT

OFFERED IN THE HOUSE BY REPRESENTATIVE DAVIES

TO: CSHB 325(O&G)

Page 1, line 1:

Delete "exemption from payment of royalty"

Insert "modification of royalty due"

Page 1, line 8:

Delete "royalty is not payable"

Insert "a lessee who makes application for and obtains an exemption under this subsection shall be granted a modification of royalty due on production"

Page 1, line 13:

Delete "exemption from payment of royalty"

Insert "modification of royalty due"

Page 2, following line 18:

Insert a new subparagraph to read:

"(A) demonstrates to the satisfaction of the Legislative Budget and Audit Committee, hereinafter "committee", that modification of royalty due under this subsection is reasonably necessary to allow for oil production from the lease that would not otherwise be feasible; as a condition of meeting the

requirement set out in this subparagraph, the committee may require the lessee making application for the royalty modification to pay for the services of an independent contractor, qualified to evaluate hydrocarbon development, production, transportation, and economics, who is selected by the committee to assist in evaluating the application and financial and technical data; selection of an independent contractor under this subparagraph is not subject to AS 36.30.020; if, on the basis of the lessee's application, the report of the independent contractor, and other evidence of record, the committee finds a modification from payment of royalty under this subsection is reasonably necessary to allow for the production of the oil from the lease, the committee shall submit a joint resolution authorizing the modification; the modification shall take effect upon adoption of the resolution by both houses of the legislature; and"

Reletter the following subparagraphs accordingly.

Page 2, line 20:

Delete "exemption from royalty payment"

Insert "modification of royalty due"

Page 2, line 22:

Delete "exemption"

Insert "modification"

Page 2, line 27:

Delete "exemption"

Insert "modification"

(9)

# HOUSE COMMITTEE REPORT

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  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, DNR  fiscal note(s) \_\_\_\_\_

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

SIGNING WITH RECOMMENDATIONS	DP	DNP	NR	AM
<i>Wene</i>				X
<i>Paul E. Davis</i>				X
<i>Ed. K. Williams</i>	✓			
<i>Joseph</i>	✓			
<i>Alvin Cluster</i>	✓			
<i>John</i>	✓			
<i>Scott</i>	✓			

CHAIR'S SIGNATURE *Joseph*