HB

506

HOUSE COMMITTEE REPORT

(7)

Date Referred: February 18, 1992 FURTHER REFERRALS: Finance

Date of Committee Action: 2/28/92

The STATE AFFAIRS Committee considered: HB 506

HOUSE BILL NO. 506 PF DIVIDEND CHECK-OFF FOR ANWR SUPPORT

"An Act relating to contributions from permanent fund dividends to be used for generating national support for the development of natural resources in the Arctic National Wildlife Refuge; and providing for an effective date."

RECOMMENDATIONS: [X] the same title
be replaced with CSHB 506 (STA) [ ] a new title

[ ] have attached amendments(s)

[X] do pass

[ ] do not pass

[ ] no recommendations

[ ] individual recommendations

[ ] additional referral to the _____ Committee

ADOPTS: _____ letter of Intent

ATTACHES NEW FISCAL NOTE(s): (Dept) APPROVES PREVIOUS: (Dept/Date)

[X] fiscal impact: Revenue [ ] fiscal note(s) _____

[ ] zero fiscal note _____ [ ] zero fiscal note(s) _____

SIGNING DO PASS	DP	OTHER RECOMMENDATIONS	DNP	NR	AM
Eugene A. Kubina	Y				
Jeffrey Meekins	Y				
Jim Nordlund	Y				
Mike Miller	Y				
W. D. Sumner	Y				

Eugene A. Kubina
CHAIRMAN'S SIGNATURE

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[ ] zero fiscal note _____ [ ] zero fiscal note(s) _____

SIGNING DO PASS	DP	OTHER RECOMMENDATIONS	DNP	NR	AM
Eugene A. Kubina	✓				
Ulmer Meekie	✓				
Sam Williams	✓			—	
Mike Miller	—				
W. D. Sumberg	✓				

Eugene A. Kubina
CHAIRMAN'S SIGNATURE

Alaska State Legislature

Chairman
State Affairs
Committee

Legislative Council

Transportation
Committee

Representative Eugene Kubina

During Session:
State Capitol
P.O. Box V
Juneau, Alaska 99811
(907) 465-4859

During Interim:
P.O. Box 240
Valdez, Alaska 99686
(907) 835-2111

March 1, 1992

MEMORANDUM

TO: House Finance Committee Members

FROM: Rep. Gene Kubina, Chairman
House State Affairs Committee

RE: CSHB 506

On Friday, February 28, 1992, the House State Affairs Committee held a hearing on HB 506 - relating to Permanent Fund Dividend Check-Off for ANWR Support. The Committee adopted a committee substitute which lowered the $50.00 amount to $25.00 and added the year of 1994 to the program.

One major concern that the Committee had with HB 506 was the administrative cost of the program. The initial cost was $16,600. for FY 93 and an additional $16,200. for FY 94. Due to this factor, over 600 Alaskans will need to contribute funds from their dividends each year before any support for ANWR will be realized. We strongly recommend that the House Finance Committee consider taking these costs out of the General Fund rather than taking them out of the Permanent Fund Dividend program. In this way, the people who choose to donate their money to support ANWR will be able to do just that rather than paying for the administration of the program. Thank you very much for your attention to this matter.

Alaska State Legislature

Session
State Capitol
Juneau, AK 99801
(907) 465-4949

Randy Phillips
State Representative
House District 15

Interim
P.O. Box 142
Eagle River AK 99577
(907) 694-4949

Member
House Finance Committee

A

Memorandum

FEB 19 1992

TO: Representative Gene Kubina, Chairman

FROM: Representative Randy Phillips RP

DATE: February 19, 1992

RE: House Bill 506, "An Act relating to contributions from permanent fund dividends to be used for generating national support for the development of natural resources in the Arctic National Wildlife Refuge; and providing for an effective date."

House Bill 506 has been referred to the State Affairs Committee.

Please consider this as my formal request that H.B. 506 be scheduled before your committee for an early hearing.

If you have any questions or comments do not hesitate to call me at 4949. Your cooperation is appreciated.

Alaska State Legislature

Randy Phillips
State Representative
House District 15

Member
House Finance Committee

Session
State Capitol
Juneau, AK 99801
(907) 465-4949

Interim
P.O. Box 142
Eagle River AK 99577
(907) 694-4949

Memorandum

TO: Representative Gene Kubina, Chairman

FROM: Representative Randy Phillips RP

DATE: February 19, 1992

RE: Sponsor Statement in Support of;
House Bill 506, "An Act relating to contributions from permanent fund dividends to be used for generating national support for the development of natural resources in the Arctic National Wildlife Refuge; and providing for an effective date."

House Bill 506 would provide that each Alaska resident who applies for a permanent fund dividend be given the option of donating $50 of that dividend to a special fund to be used for generating national support for the development of natural resources in the Arctic National Wildlife Refuge.

The coastal plain of the Arctic National Wildlife Refuge (ANWR) may hold a deposit of oil and natural gas that is nearly equal to that which has been found at Prudhoe Bay. As oil production declines in the existing North Slope fields, it is critical for new fields to be brought on line. ANWR holds the best chance of any area in Alaska to hold a significant quantity of oil and gas.

When U.S. Senator Ted Stevens addressed the joint session of the Alaska Legislature on February 13, 1992, he proposed that Alaskans be allowed to contribute a portion of their permanent fund dividend to a fund to be used to promote the opening of ANWR. House Bill 506 would provide a mechanism for individual Alaskans to show their support for the opening

of ANWR and at the same time provide funding for a grassroots campaign to move national public opinion toward supporting the opening of ANWR.

The Alaska State Legislature recognizes the value of opening ANWR to oil and gas development. For FY92 the Legislature authorized the expenditure of $3.1 million, in the Governor's budget, for the promotion of oil and gas exploration in ANWR. Also in 1991, both houses of the Legislature passed their own version of SJR21, *Relating to oil and gas exploration and production within, and the state's royalty shares in the development of, the Arctic National Wildlife Refuge.* While the two houses have not agreed to the final form of SJR21, both houses have passed a version of SJR21 that clearly shows support for exploratory drilling and, if practical, oil production in ANWR.

House Bill 506 provides a simple mechanism for individuals to express their support.

If you have any questions or comments do not hesitate to call me at 4949. Your cooperation is appreciated.

FISCAL NOTE

STATE OF ALASKA
1992 LEGISLATIVE SESSION

BILL NO. HB 506

Revision Date:
Title: Contributions from permanent fund dividends
Sponsor: Phillips, Miller, MacLean
Requestor: House State Affairs

Agency Affected: Revenue
BRU: Permanent Fund Dividend Division
Components: Permanent Fund Dividend Division
COMPONENT SERIAL NO. 9 8 1

EXPENDITURES/REVENUES: (Thousands of Dollars)

	FY 93	FY 94	FY 95	FY 96	FY 97	FY 98
OPERATING						
PERSONAL SERVICES	14.1	13.7				
TRAVEL						
CONTRACTUAL	2.5	2.5				
SUPPLIES						
EQUIPMENT						
LANDS & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	16.6	16.2				
CAPITAL						
REVENUE						

FUNDING: (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER (SPECIAL ANHR ACCOUNT)	16.6	16.2				
TOTAL	16.6	16.2				

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

Estimate of current year impact: None.

ANALYSIS: See attached.

Prepared By: Thomas C. Williams
Phone: 465-2323
Division: Permanent Fund Dividend Division
Date: February 20, 1992

Approved by Commissioner:
Agency: Revenue
Date: 2/20/92

Distribution (by preparer): Legislative Finance, Legislative Sponsor, Requestor, OMB, & Impacted Agency(ies).

ALASKA DEPARTMENT OF REVENUE
PERMANENT FUND DIVIDEND DIVISION
HB 506 ANALYSIS
As of February 20, 1992

Assumptions:

1. This bill is the only Permanent Fund Dividend checkoff bill that will become law. This fiscal note would change if other PFD checkoff bills are introduced and become law.

2. The Department of Administration will charge the Department of Revenue for the required additional computer time.

3. The cost of programming changes will be a one-time cost. Ongoing maintenance of new programs would be accomplished by existing staff. The computer system will need to be changed to account for the change in the program, to establish new accounting controls and to provide for the transfer of funds to the trust account. The following tasks will require the following programming hours.

	Hours
a. Wang Data Entry Processing Updates (1) Data entry (2) Batch lists (3) Corrections (4) Wang to IBM transfer	75.0
b. IBM File Processing Updates (1) Edits (2) Batch listings (3) Worksheets	30.0
c. CICS Online Programs for Lookup and Changes	37.5
d. Nightly Update of Changes	22.5
e. Warrant Jobs (1) Printing warrants with different amounts. Include check stub messages. (2) Modify warrant registers as needed for balancing. (3) Create new program for transferring accumulated decisions to trust account and to account for the reserve necessary due to returned and cancelled PFD warrants.	90.0
f. Miscellaneous (1) Setting up test files on IBM (2) Systems testing	45.0
Total Hours	300.0

4. One Document Processor I position would be required for three months to assist in the manual review and coding of 525,000 applications. One Data Processing Clerk I position would be required for two months to assist in data capture.

5. Garnishments and assignments will take precedence over contributions in the order established by statute. The PFD Division will only honor contributions to the extent than an individual's permanent fund dividend has not otherwise been assigned or garnished.

6. The PFD Division will be responsible for electronically transferring contributions to the special fund account.

7. The Treasury Division will be responsible for the accounting and management of the special account.

Cost Summary:

	FY 93	FY 94
1. Personal Services		
1 PPT Analyst/Programmer V, R21 @ $7,057.40/Mo including salary and benefits for 2 months. PCN 04-6011 would be funded for an additional 2 months.	$ 14.1	$ -0-
1 PPT Document Processor I, R7 @ $2,660.39/Mo including salary and benefits for 3 months. This position represents the equivalent of the additional time and effort.	-0-	8.0
1 PPT Data Processing Clerk I, R8 @ $2,867.86/Mo including salary and benefits for 2 months. This position represents the equivalent of the additional time and effort.	-0-	5.7
Total Personal Services	14.1	13.7
2. Contractual Services		
a. Data Processing Chargeback	2.5	2.5
TOTAL COST	$ 16.6	$ 16.2

Alaska State Legislature

Legislative Research Agency

P.O. Box Y
Juneau, AK 99811-3100
Phone: (907) 465-3991
Fax: (907) 463-3331

June 18, 1990

MEMORANDUM

TO:

FROM:

RE: Economic Prospects of ANWR versus Marginal Fields
Research Request 90.147

You asked if the state's economic interests might be best served by promoting the development of known marginal fields on the North Slope rather than urging the federal government to open the Arctic National Wildlife Refuge (ANWR) to drilling.

There may be valid social and environmental reasons for the state of Alaska not to promote petroleum exploration in ANWR; indeed, to attempt to block the federal government from authorizing further exploration. However, from a strictly economic perspective, it is hard to develop a case against penetration of ANWR by the oil industry. This is because 1) the geologic structures in ANWR hold the potential of very large discoveries; 2) there is very little the state can reasonably do to promote the development of known marginal fields elsewhere on the North Slope; 3) development of a discovery in ANWR, even a major discovery, should not be an obstacle to development of marginal fields elsewhere; 4) development of a commercial discovery in ANWR would stimulate the exploration for additional fields and make possible the development of new marginal fields; and 5) development of a commercial discovery in ANWR would help maintain throughput of the trans-Alaska pipeline, and thereby lower the cost of pipeline transportation for all North Slope production (and increase state royalty and severance tax revenue).

Potential of ANWR

On the basis of information obtained from surface studies and seismic surveys, the coastal plain of ANWR is underlain by some very large geologic structures that could contain quantities of oil comparable to the Prudhoe Bay field. Of course, whether they do or not can be known only by drilling. There have been many promising structures in Alaska that were found to be dry by drilling. The Mukluk formation in federal waters of the Beaufort Sea is the best-known recent example of these, but there have been others as well. Indeed, approximately 75 wells have been drilled in federal off-shore lands in the last decade, and only one (in the Beaufort Sea) may prove to have oil of commercial significance.

The U.S. Department of the Interior estimates that in the coastal ANWR plain there is a 19 percent probability of discovering hydrocarbons that are economic to produce. The department's geologists believe that a field of about 450 million barrels of recoverable oil is the economic threshold. They estimate that, if a commercial field is found, it has a roughly 50-50 chance of containing 3.23 billion recoverable barrels, and a five percent chance of containing over nine billion recoverable barrels. Estimates by the state of Alaska's geologists are somewhat more pessimistic, but impressive nonetheless.

The economic impact on the state of a multi-billion barrel discovery, under any conceivable revenue-sharing formula that might be adopted by Congress, would eclipse the impact of developing known marginal fields on the North Slope today.

Most North Slope marginal fields are economically marginal because of their small size in relation to the high cost of development in the arctic. The most recent discovery on the North Slope, at Pt. McIntyre, is estimated to contain about 300 million barrels of recoverable oil. (If this field were discovered in West Texas, it would be considered a major find.) What makes this field commercial in the arctic is its proximity to the Prudhoe Bay infrastructure. Like other North Slope marginal fields, it is comparatively small: Pt. McIntyre is thought to contain only three percent of the recoverable reserves of Prudhoe Bay.

Attached to this memorandum is an excerpt from *Historical and Projected Oil and Gas Consumption, January, 1990*, by the Division of Oil and Gas of the Department of Natural Resources. Table 2.1 shows the estimated productive capacity, under three progressively optimistic scenarios, of known oil fields in Alaska. Note that West Sak is potentially a very large producer. However, West Sak oil is heavy and contained in sands that make it very expensive to produce. Development of this field demands robust oil prices. Royalty and severance tax concessions by the state might encourage the field owners to begin production sooner than they ordinarily would, but the economic return to the state under these conditions may not be great. (See discussion below.)

Policy Options for Marginal Fields

It is not clear what the state of Alaska can prudently do to encourage the development of more North Slope marginal fields. The recent economic limit factor (ELF) revision virtually eliminated severance taxes on most of the smaller fields (or that was its intent, in any case). For the most part, the development of these fields hinges on the price of oil (more precisely, expectations of the future price of oil). While further state economic subsidy might tip the scales toward development, the net long-term benefits of granting such subsidy is not clear. In any case, whether or not there is a net economic benefit to the state by granting, for example, royalty and/or severance tax concessions to promote the development of marginal fields, the potential benefit is insignificant in comparison to the potential benefit to the state of pursuing ANWR development.

Simultaneous Development of ANWR and Marginal Fields

While a major development effort in ANWR might delay the development of some marginal fields for a time, there is no reason to believe that development of both resources would not occur simultaneously if economic conditions were favorable for putting marginal fields into commercial production. While a company with commercial ANWR acreage preoccupied with developing it might postpone development of a small field elsewhere, generally speaking marginal fields will be produced when it is economically feasible to do so. It seems unlikely that a shortage of capital or manpower, for example, would be created by the demands of ANWR development and thereby impede development of marginal fields.

Commercial development of discoveries in ANWR will require strong oil prices. Department of the Interior estimates of production in ANWR are based on prices of $22 per barrel and higher, plus constantly escalating real prices throughout the life of the field. These price assumptions would doubtless be sufficient to bring known marginal fields on the North Slope into production.

ANWR and Development of New Marginal Fields

From the state's economic point of view, development of a major field in ANWR is desireable because it would stimulate more exploration and make the production of smaller fields in the vicinity feasible. Small fields in the arctic must share infrastructure that is justifiable by huge fields. All of the smaller fields on the North Slope combined, including Kuparuk, could not support construction of the trans-Alaska pipeline. Prudhoe Bay made possible the development of the Kuparuk field and the other producing fields on the North Slope. Development of a major discovery in ANWR would lead to additional exploration in the vicinity (as did the discovery at Prudhoe Bay), and improve the economics of developing smaller local fields that could not bear the cost of a connecting pipeline and other facilities on their own.

Lower Transportation Costs

ANWR production would help rather than hinder the development of known marginal fields because it would lower pipeline tariffs for all oil produced on the North Slope. The trans-Alaska pipeline currently has a throughput capacity of about two million barrels per day. Approximately 1.85 million barrels per day are currently being transported by the pipeline. This daily throughput will fall as production from the Prudhoe Bay and Kuparuk fields declines. As throughput declines, the charge per barrel of oil going through the pipeline will increase because this oil must pay operating costs of the pipeline, which will not decline significantly as volumes decline. New production from ANWR

field(s) would help sustain throughput levels, and thereby improve the economics of production from marginal fields. Also, to the extent ANWR production lowered pipeline tariffs, the state's royalty and severance tax returns from all North Slope production would increase.

I hope this information is useful to you. If you would like further analysis of the question, please contact this agency.

Attachment

CHAPTER 2
RESERVE ESTIMATES AND ROYALTY SHARE

Introduction

This chapter discusses estimates of Alaska's oil and gas reserves and the state's royalty share of these reserves. The reserve estimates have been developed for three different cases. Analysts used the specific royalty terms of individual oil and gas lease contracts to calculate the state's royalty share of the reserves in each field. The low-range estimates assume falling oil and gas prices and/or poorer-than-predicted reservoir performance. The mid-range estimates assume relatively stable oil and gas prices and anticipated reservoir performance. The high-range estimates assume rising oil and gas prices and/or better-than-predicted reservoir performance.

Estimated oil and gas reserves and royalty share are shown in Table 2.1. Cook Inlet and the North Slope estimates were derived from different information sources, and within each region reserves are classed as "proven and developed" or "proven but undeveloped or shut-in." These subcategories distinguish those volumes of oil and gas which are readily marketable from those which need additional investment in facilities and transportation systems which, in turn, will delay their development.

Cook Inlet

Considerable information exists about the oil and gas reserves and potential in the Cook Inlet area. While there has been renewed interest in Cook Inlet exploration, infill drilling programs, and remedial field work, we do not anticipate that significant new reserves will be added in the near future. Recent changes in working interest ownership of several Cook Inlet gas fields have resulted in the development of some of these previously shut-in fields. The reserves are assumed to remain constant for low-, mid- and high-range estimates. Cook Inlet reserves account for about 3.4% of the low, 1.2% of the mid, and 0.6% of the high estimates of statewide total oil and gas reserves.

North Slope

Oil and gas reserve estimates shown in Table 2.1 are for currently leased state lands. Operators produce North Slope oil from the Sadlerochit and the Lisburne reservoirs in the Prudhoe Bay Unit, the Kuparuk River reservoir in the Kuparuk River Unit, and the Endicott reservoir in the Duck Island Unit. Production from the Kuparuk River reservoir in the Milne Point Unit which was shut-in January 1987, resumed in April of 1989. Average production in 1989 has been 12,00 barrels per day, but is expected to rise to 30,000 barrels per day in 1990.

Additional enhanced oil recovery operations at Prudhoe Bay Unit, over and above those already in operation, recovery of additional gas condensate and gas liquids from the Sadlerochit and Lisburne gas caps and enhanced oil recovery from the Kuparuk and Lisburne reservoirs represent an oil resource (versus oil reserves) of about two billion additional barrels of liquids which may or may not be economically recoverable sometime in the future.

The economics of enhanced oil recovery operations are extremely sensitive to incremental capital costs, changing markets and expected wellhead crude oil prices (which are influenced in part by pipeline tariffs, royalties and taxes). Systematic recovery of liquids from the Sadlerochit and Lisburne gas caps (and absent major gas sales, simultaneous reinjection of the dry gas back into the reservoirs) would require additional investment by the respective gas cap owners.

Depending on the nature of the liquids recovered and intended for sale, the owners of the Trans-Alaska Pipeline System (TAPS) may also have to invest in additional infrastructure, as well as retrofit existing pipeline, storage and shipping facilities to ship portions of these gas liquids. In the fall of 1988, the three major gas owners in the Prudhoe Bay Unit (ARCO, Exxon and BP America) announced that a major new gas project they were reviewing (called "Super Spike") did not appear to be economically feasible at that time. Prospects for the Super Spike project do not look favorable at this time.

Installation and start up of the world's largest central gas facility at Prudhoe Bay in 1986 was designed to separate gas liquids and gas condensate from the produced gas stream, and it is a major step in establishing the infrastructure that will be needed to proceed with any future large-scale gas sales or expanded gas cycling or gas cap liquid recovery projects. The currently configured plant separates propane, butane and heavier

hydrocarbon liquids from the produced gas stream and it could be modified to recover ethane. In addition to the heavier hydrocarbon liquids being shipped through TAPS today, significant ethane,propane and butane could be shipped through TAPS if the pipeline system and the storage and loading facilities at Valdez were modified. However, until a long term market can be identified for some or all of these three products, no major new gas liquids sale project will proceed.

Conversion of any of the above 'resources' to the 'proven reserves' category and the timing of that conversion must be viewed with extreme caution at this point. However, because billions of barrels of oil will remain in the ground at the Prudhoe Bay and Kuparuk River Units after completion of existing primary and secondary oil recovery operations, sufficient economic incentives to develop additional economic means of enhanced oil recovery will exist well into the future. For instance, Prudhoe Bay Sadlerochit Reservoir's ultimate recovery was originally estimated to be 9.6 billion barrels but has slowly risen to 11 to 12 billion barrels. If this current estimate holds true, some 11 to 12 billion barrels will remain in place. However, new enhanced oil recovery technologies, increased infill drilling and horizontal drilling technology may increase the 11 to 12 billion barrel recovery figure even further.

Various North Slope leaseholders are continuing their experiments to economically produce the vast amounts of "heavy," low gravity oil in the shallow Tertiary and Cretaceous age sands primarily located west of Prudhoe Bay field in the Kuparuk River Unit area. Technology and equipment already exist to produce these types of oil deposits in more temperate, less costly operating and marketing climates. However, permafrost considerations, surface-related permitting, construc-

ESTIMATED REMAINING RESERVES AND ROYALTY SHARE

TABLE 2.1

	OIL (MILLIONS OF BARRELS)						GAS (BILLIONS OF CUBIC FEET)					
	RESERVES			ROYALTY SHARE			RESERVES			ROYALTY SHARE		
	LOW	MID	HIGH	LOW	MID	HIGH	LOW	MID	HIGH	LOW	MID	HIGH
NORTH SLOPE												
DEVELOPED												
East Barrow	—	—	—	—	—	—	7 [1]	7 [1]	7 [1]	—	—	—
Endicott	215 [2]	260 [2]	415 [2]	30	39	58	543 [2]	782 [2]	1,182 [2]	81	139	185
Kuparuk River Unit	845 [2]	881 [2]	1,005 [2]	98	111	130	395 [2]	620 [2]	870 [2]	49	85	84
Lisburne reservoir	83 [2]	130 [2]	250 [2]	10	18	44	788 [2]	848 [2]	948 [2]	98	111	123
Milne Point Area	30	36	83	5	8	16	—	—	—	—	—	—
Prudhoe Bay Unit	4,430 [2]	4,730 [2]	5,430 [2]	590	644	875	23,845 [3] [1]	23,845 [3] [1]	23,845 [3] [1]	3,230	3,230	3,230
South Barrow	—	—	—	—	—	—	8 [1]	8 [1]	8 [1]	—	—	—
UNDEVELOPED												
Beaufort Sea	0	150	300	0	20	60	—	—	—	—	—	—
N. Thomson/Flaxman Is	0	0	300	0	0	30	0 [2]	0 [2]	5,000 [2]	0	0	625
West Sak	0	500	3,000	0	63	378	—	—	—	—	—	—
Niakuk	0	30	80	0	8	10	—	—	—	—	—	—
Point McIntyre	150	200	300	19	25	38	—	—	—	—	—	—
SUBTOTAL	5,360	6,950	11,310	750	968	1,647	27,817	32,843	33,862	3,458	3,815	4,228
COOK INLET												
PROVEN AND DEVELOPED												
Beaver Creek		1 [1]			0			152 [1]			0	
Beluga River		—			—			861 [1]			62	
Cannery Loop		—			—			148 [1]			8	
Granite Point		10 [1]			2			12 [1]			2	
Kenai River, Lower River, Pretty Creek, Stump Lake		—			—			—			—	
Kenai		—			—			499 [1]			62	
McArthur River		60 [1]			8			572 [1]			12	
Middle Ground Shoal		8 [1]			1			369 [1]			74	
North Cook Inlet		—			—			8 [1]			1	
Swanson River		8 [1]			1			668 [1]			84	
Trading Bay		1 [1]			0			148 [1]			0	
PROVEN BUT UNDEVELOPED OR SHUT-IN								30 [1]			4	
Beluga		—			—			—			—	
Falls Creek		—			—			11 [1]			0	
Granite Point		—			—			13 [1]			1	
Kenai Gas		—			—			3 [1]			0	
Kenai Oil		—			—			41 [1]			41	
Sterling		—			—			41 [1]			41	
West Foreland		—			—			41 [1]			41	
West Fork		—			—			30 [1]			0	
Wolf Lake		—			—			8 [1]			1	
SUBTOTAL		76			8			3,818			209	
STATE TOTAL	5,436	7,026	11,386	758	976	1,655	31,635	37,661	37,680	3,668	4,024	4,437

[illegible]

tion and operating constraints, and the projected wellhead price of the produced oil have stymied commercial development of these relatively shallow (but very large) resources.

ARCO completed one major pilot production project in the Kuparuk River Unit and laboratory research continues in an effort to improve project performance and economics. ARCO has drilled one well in a proposed 25 well program as part of a second major "West Sak" pilot production project in the Kuparuk River Unit. The operator will use a well spacing pattern which is less dense than was used in the first pilot project and will test various well bore completion techniques again in an attempt to improve individual well production rates. ARCO will also conduct a water flood program to test the influence of the larger well spacing on oil recovery and well performance. Unfortunately, the second West Sak pilot is currently suspended, and it is not known when, or *if*, ARCO will resume its West Sak testing program.

During 1989 Conoco drilled four test wells in Milne Point Unit to test the extensive shallow oil sands in that unit. With the resumption of production operations at Milne Point Unit, Conoco hopes to also begin commercial production from the shallow oil sands in the very near future.

Technology exists to produce in the range of 300,000 barrels per day of oil from the shallow north slope oil sands, but current economics do not appear to favor any type of full-scale development. In the Kuparuk River Unit, the Kuparuk River reservoir owners and the West Sak reservoir owners are discussing facilities-sharing agreements because they would greatly reduce the future West Sak development costs. As unused production and processing capacity in the Kuparuk oil production facilities become available in the late 1990s, the West Sak reservoir may be brought on line to offset some of the declining production. Development of the West Sak reserves will also require drilling many hundreds of additional wells and the construction of many more drillsites and pipelines. These costs cannot be avoided by use of facility sharing agreements.

Tables 2.2 and 2.3 list production forecasts for some of the fields listed in Table 2.1. Figure 2.1 graphs the estimates of total production and Figures 2.2 and 2.3 graph the estimates of the royalty share. North Slope oil production will decline further in 1990. The decline is beginning earlier and will be steeper than earlier forecasts indicated. Total oil production from state-owned lands will decline through the 1990s.

Currently, North Slope natural gas is not exported. Both the Alaska Natural Gas Transportation System (ANGTS) and the Trans-Alaska Gasline System (TAGS) are proposed means of moving North Slope gas to market. To date, neither project has secured financing or a guaranteed market. The continued volatility and uncertainty in oil and gas prices, the relatively abundant worldwide supplies of natural gas, and the sheer magnitude and cost of the proposed pipeline projects combine to make the prospective purchasers of the gas, the financial institutions, and the projects' sponsors all very cautious at this time. Efforts to secure markets for the gas continue. However, start up of the ANGTS or TAGS project cannot be expected until financing for one or both projects is arranged, and financing likely will not be finalized until long-term sales agreements for the gas are guaranteed. In addition, the lessees (primarily ARCO, Exxon and BP (Alaska) Inc.) have not agreed to sell the gas to either pipeline company.

Esso Resources Canada, Gulf Canada Resources and Shell Canada applied to the Canadian National Energy Board in 1988 for permission to export gas from the Canadian Beaufort Sea and MacKenzie River Delta to the United States. In October 1989 these companies received conditional approval for the export. Foothills Pipe Lines (the Canadian sponsor of the ANGST project) has filed an application with the Canadian National Energy Board to build the MacKenzie Valley gas pipeline. This project would be in direct competition with Alaska North Slope gas for potential U. S. markets, but it might also be an incentive to re-evaluate the once-proposed gas pipeline from Prudhoe Bay east across the Arctic National Wildlife Refuge to the Canadian MacKenzie River Delta area. Such a pipeline probably would be much cheaper to build than either ANGST or TAGS. At this time no estimates of construction or transportation costs are available for this type of proposal. In addition, ANWR legislation under consideration by Congress would expressly prohibit the construction of a pipeline eastward across wilderness areas in ANWR to the U.S. - Canada border.

BP (Alaska) Inc. proposes to develop the Niakuk reservoir, located about one mile offshore in the Beaufort Sea just north of Prudhoe Bay. BP estimates that the reservoir could produce up to 30,000 barrels per day of oil beginning in 1992 or

PRODUCTION FORECAST AND AVAILABLE ROYALTY OIL

TABLE 2.2

THOUSANDS OF BARRELS PER DAY

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	TOTAL
PRODUCTION FORECAST																								
NORTH SLOPE																								
Prudhoe Bay [1]	1,391	1,196	1,102	1,014	930	857	790	726	666	614	563	516	473	433	397	364	334	307	282	259	238	219	201	185
Kuparuk	300	300	293	268	270	180	175	160	135	105	80	70	60	54	45	36	30	25	20	16	13	10	8	6
Lisburne	40	40	40	40	40	37	34	31	29	27	25	23	21	19	17	15	13	11	10	9	8	7	6	5
Endicott	100	100	88	75	70	64	60	56	52	49	46	43	40	37	34	32	29	27	25	23	21	19	18	16
Milne Point	30	25	25	18	13	10	8	7	6	5	5	4	4	3	3	3	2	2	2	2	1	1	1	1
West Sak	6	6	6	6	12	12	12	25	25	50	50	100	100	100	100	150	150	150	140	130	80	75	65	60
Point McIntyre	5	5	25	60	80	80	64	48	44	36	34	32	29	27	25	23	21	19	17	15	14	12	11	10
Beaufort Sea	5	5	5	5	5	5	5	5	5	5	5	49	44	38	34	30	26	23	20	18	16	14	13	12
Natuk	5	5	5	20	20	20	17	14	12	10	9	8	7	6	5	4	4	3	3	2	2	2	1	1
SUBTOTAL	1,881	1,686	1,583	1,501	1,367	1,251	1,149	1,067	968	893	843	765	695	642	580	547	515	466	426	379	324	266	229	175	148
COOK INLET																								
Granite Point	7.9	7.3	6.6	6.2	6.6	6.1																		
McArthur River	16.6	16.6	16.6	16.7	16.6	13.6																		
Trading Bay	2.4	2.4	2.3	2.1	1.8	1.6																		
Middle Ground Shoal	7.8	7.5	7.1	6.4	6.6	6.2																		
SUBTOTAL	34.7	33.7	34.0	31.4	29.2	25.4																		
STATE TOTAL	1,916	1,720	1,644	1,532	1,396	1,276	1,149	1,067	968	893	843	765	695	642	580	547	515	466	426	379	324	266	229	175	148
AVAILABLE ROYALTY OIL																								
NORTH SLOPE																								
Prudhoe Bay	146	150	138	127	117	107	98	91	84	77	69	62	56	50	45	41	37	33	29	26	23	20	18	16
Kuparuk [2]	30	30	29	27	25	24	22	19	16	13	11	9	7	6	5	4	3	3	2	2	1	1	1	0
Lisburne [3]	5	5	5	5	5	5	4	4	3	3	3	2	2	2	1	1	1	1	1	0	0	0	0	0
Endicott [3]	10	10	10	11	10	9	8	8	7	7	6	6	5	5	4	4	4	3	3	3	2	2	2	1
Milne Point [4]	6	6	6	5	3	2	2	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
West Sak [7]	0	1	1	1	2	2	2	3	3	6	6	12	12	12	12	18	18	18	17	16	10	9	8	7
Point McIntyre	0	0	3	8	10	10	8	6	5	4	4	4	3	3	3	3	3	2	2	2	2	1	1	1
Beaufort Sea	0	0	0	0	0	0	0	0	0	1	1	6	5	5	4	4	4	3	3	2	2	2	2	1
Natuk	0	0	0	3	3	3	2	2	2	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
SUBTOTAL	209	212	197	187	175	160	146	133	121	112	100	94	87	84	73	71	64	64	53	47	41	34	30	23	19	16
COOK INLET																								
Granite Point	0.8	0.8	0.8	0.8	0.7	0.6																		
McArthur River	2.4	2.4	2.3	2.1	1.8	1.7																		
Trading Bay	0.3	0.3	0.3	0.3	0.3	0.2																		
Middle Ground Shoal	0.8	0.8	0.8	0.8	0.7	0.7																		
SUBTOTAL	4.4	4.4	4.4	3.8	3.6	3.2																		
STATE TOTAL	213	216	201	191	179	163	146	133	121	112	100	94	87	84	73	71	64	64	53	47	41	34	30	23	19	16
IN-KIND ROYALTY OIL SALES																								
Mobil	36	36	36	36	36	36	36	36	36	36	36	36	36	36										
Govt A [7]	4	4	4	3	3																			
Texaco (Old) [8]	41	37	34	31	29																			
Texaco (New) [9]	23	21	19	18	18																			
Chevron [10]	16	16	13	12	11																			
Petro-Star [11]	8	8	4	0	0	0																		
Cook Inlet	25																							
STATE TOTAL	153	118	109	102	97	36	36	36	36	36	36	36	36	36										
IN-VALUE ROYALTY OIL	134	100	92	89	79	123	110	96	90	77	73	63	57	48	73	71	64	64	53	47	41	34	30	23	19	16

Note: Numbers may not sum to totals due to rounding errors.

[1] Oil, condensate and NGLs

[2] 12.5% of production

[3] 12.5% of production (weighted average)

[4] 12.5% of production (weighted average)

[5] 16.7% of production

[6] 8.3% of production

[7] 2.66-3% of Prudhoe Bay production. Contract expires June 30, 1996

[8] Maximum 2% of Prudhoe Bay production. Contract expires January 1995.

[9] Maximum 13.66-3% of Prudhoe Bay production. Contract expires January 1, 1995. Texaco commenced deliveries on October 1, 1993 under contract effective December 8, 1993.

Texaco terminated the entire volume under this contract effective August 26, 1995 but has the option of reinstituting on six months notice.

[10] Maximum 8.5% of Prudhoe Bay production. Contract expires January 1, 1995.

[11] Maximum 5.5% of Prudhoe Bay production. Contract expires January 1, 1995.

[12] 4.166-3% of Prudhoe Bay royalty oil. Initial purchase would be 8,000 BPD. Contract expires September 30, 1996.

[13] 12.5% of West Sak & Cook Inlet royalty production.

[14] 1 month

PRODUCTION FORECAST AND AVAILABLE ROYALTY OIL, FOR PRODUCING NORTH SLOPE FIELDS

TABLE 2.3

THOUSANDS OF BARRELS PER DAY

		1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	TOTAL
PRODUCTION FORECAST																												
PRUDHOE BAY [1]	1.35%	1,351	1,196	1,102	1,014	932	847	769	726	686	614	545	486	434	403	343	309	284	247	215	187	163	136	116	100	86	77	4,990,316
Amerada	0.54%	7	6	6	5	5	4	4	4	4	3	3	3	2	2	2	2	2	1	1	1	1	1	1	1	0	0	26,379
Arco	21.75%	290	261	240	221	203	187	172	158	149	134	120	106	95	88	75	67	62	54	47	41	36	30	25	22	19	16	1,087,723
BP	50.84%	675	607	560	514	473	434	400	368	339	311	283	252	227	204	174	155	144	125	109	95	83	70	58	51	43	36	2,494,739
Chevron	0.67%	9	8	7	7	6	6	5	5	4	4	4	3	3	3	2	2	2	2	1	1	1	1	1	1	1	0	33,453
Exxon	21.75%	290	261	240	221	203	187	172	158	149	134	120	106	95	88	75	67	62	54	47	41	36	30	25	22	19	16	1,087,699
ELAE	0.04%	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,349
Marathon	0.01%	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,446
Mobil	1.04%	25	23	21	19	18	16	15	14	13	12	10	9	8	7	6	6	5	4	4	3	3	2	2	2	1	1	52,731
Phillips	1.04%	25	23	21	19	18	16	15	14	13	12	10	9	8	7	6	6	5	4	4	3	3	2	2	2	1	1	52,106
Shell	0.11%	3	3	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	5,746
Texaco	0.54%	7	7	6	5	5	4	4	4	4	3	3	3	2	2	2	2	2	1	1	1	1	1	1	1	0	0	26,379
KUPARUK		360	320	296	268	239	195	173	156	135	105	85	73	58	44	36	30	25	20	16	13	0	0	0	0	0	0	896,235
Arco	63.01%	158	138	140	120	117	101	85	80	68	58	44	38	29	24	19	15	11	8	6	4	0	0	0	0	0	0	564,599
BP	37.04%	113	113	105	94	83	71	60	55	48	38	34	26	21	17	13	11	9	6	5	3	0	0	0	0	0	0	1,029
Chevron	0.11%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,041
Exxon	0.27%	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,427
Mobil	0.27%	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36,796
Union	4.25%	13	13	12	11	9	7	6	6	5	4	3	3	2	2	1	1	1	0	0	0	0	0	0	0	0	0	164,000
LISBURNE		82	82	82	82	82	57	34	31	29	25	21	16	13	9	6	4	3	2	1	0	0	0	0	0	0	0	61,012
Arco	43.00%	18	18	18	18	18	18	14	13	11	10	9	7	6	4	3	2	1	1	0	0	0	0	0	0	0	0	26,346
BP	20.00%	8	8	8	8	8	7	6	6	5	4	4	3	3	2	1	1	1	0	0	0	0	0	0	0	0	0	61,012
Exxon	40.00%	16	16	16	16	16	15	14	12	11	10	8	6	5	3	2	1	1	1	0	0	0	0	0	0	0	0	262,675
ENDICOTT		100	100	95	75	70	65	55	50	45	40	35	30	25	20	15	10	5	0	0	0	0	0	0	0	0	0	39,013
Amerada	10.00%	10	10	9	7	7	6	5	5	4	4	3	3	2	2	1	1	0	0	0	0	0	0	0	0	0	0	96
Arco	0.01%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	146,573
BP	67.01%	68	68	64	51	48	44	38	34	31	28	24	21	17	14	10	7	3	0	0	0	0	0	0	0	0	0	1,026
Chit	0.01%	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	366
Exxon	0.13%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36,446
Exxon	21.02%	21	21	19	16	15	14	13	11	10	8	7	5	4	3	2	1	1	0	0	0	0	0	0	0	0	0	1,099
NANA	0.34%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36,761
Unocal	10.67%	11	11	9	7	7	5	4	4	3	3	2	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0	54,750
MILNE POINT		30	28	26	16	13	10	8	7	6	5	4	3	2	2	1	1	0	0	0	0	0	0	0	0	0	0	6,513
Chevron	11.37%	3	3	3	2	2	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	56,000
Conoco	72.10%	22	19	14	12	9	7	5	4	3	3	2	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0	6,734
Oxy	16.54%	5	5	5	4	4	3	2	2	2	2	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	6,366,195
TOTAL		1,901	1,683	1,527	1,356	1,270	1,150	1,006	938	877	784	700	617	530	472	415	361	314	272	234	202	173	140	118	100	86	77	
AVAILABLE ROYALTY OIL																												
Prudhoe Bay [2]		190	160	136	121	107	107	90	81	84	77	68	62	54	50	45	41	36	31	27	23	20	17	15	13	11	0	915,750
Kuparuk [2]		36	36	36	31	28	24	22	19	16	13	11	9	7	6	5	4	3	2	1	1	0	0	0	0	0	0	117,000
Lisburne [2]		8	8	8	8	8	7	6	6	5	4	4	3	3	2	2	1	1	1	0	0	0	0	0	0	0	0	16,254
Endicott [3]		14	14	12	11	10	9	8	7	6	5	5	4	3	3	2	2	1	1	0	0	0	0	0	0	0	0	36,003
Milne Point [4]		3	3	3	3	2	2	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6,264
TOTAL		270	211	195	176	161	148	128	123	111	100	89	79	67	58	52	48	41	34	28	24	20	17	15	13	11	0	795,000
IN-KIND ROYALTY OIL SALES																												170,000
Mobil		35	35	35	35	35	35	35	35	35	35	35	35	35	35													6,750
GVEA [5]		4	4	4	3	3																						62,424
Texaco [Old] [6]		41	37	34	31	28																						36,246
Texaco [New] [7]		25	21	18	16	15																						24,427
Chevron [8]		12	12	12	12	11																						6,750
Petroleter [9]		3	3	3	3	3	3																					316,532
TOTAL		120	112	106	102	97	38	35	35	35	35	35	35	35	35													
IN-VALUE ROYALTY OIL		103	85	84	74	64	106	105	87	76	65	54	43	32	23	52	45	36	34	29	25	20	16	15	13	11	0	451,000

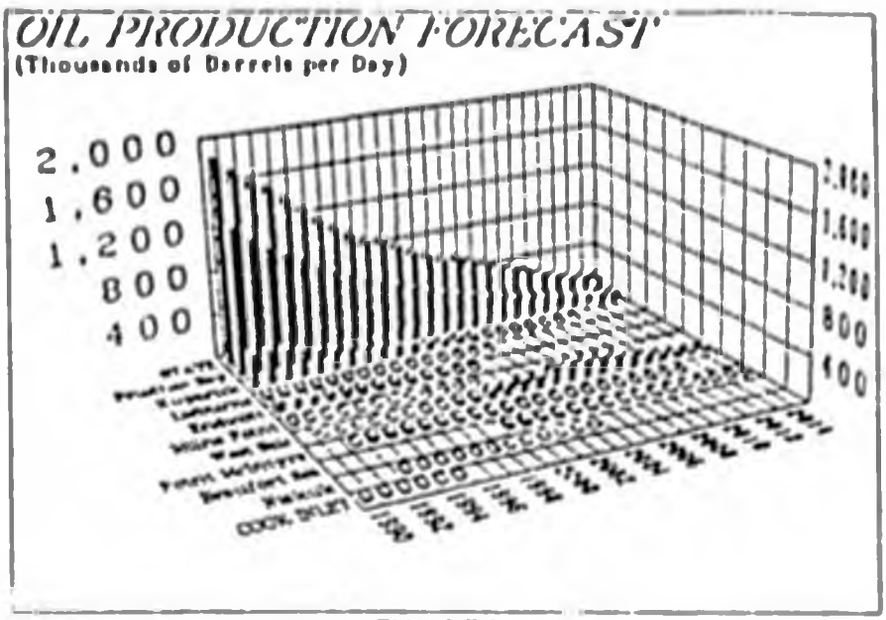


FIGURE 21

1993 if development plans are approved in a timely manner. The proposal includes a 6,600-foot, gravel-fill causeway which state and federal agencies are now reviewing. The U.S. Army Corps of Engineers had issued a preliminary finding that the causeway was unacceptable as proposed but has since withdrawn that finding. Permit applications are also still pending with state agencies. The North Slope Borough has approved the application. State agencies might not approve the project, or BP may be required to substantially modify its design.

In early 1988, Alaska became the number one oil producing state in the nation. However, with the ongoing decline in production at Prudhoe Bay, Texas has again regained the number one producing spot.

Prudhoe Bay's current production rate of 1.40 million barrels per day of crude oil and condensate is expected to continue its slow decline in 1990. The actual rate of the decline will be influenced by the level of infill development drilling, rate of development of the field's West End and P Pad, scheduling of well workovers and equipment repairs, water and miscible gas injection rates, and the capabilities of the installed and to-be-installed gas handling and water handling facilities.

The Prudhoe Bay owners have approved the construction of GHX-1, a major new gas handling expansion project, and construction is underway at this time. The project is designed to boost the amount of gas that can be produced, handled and reinjected from about 3.5 billion cubic feet per day to just over 5 billion cubic feet per day. Bottlenecks in gas processing facilities and insufficient gas compressor capacity are causing a gas overload in the field production facilities as gas production from the field increases. Operators are reducing oil production rates because the gas processing facilities cannot handle the increased amount of gas associated with the higher oil production rates. The average oil production rate in 1990 might not reach the allowed annual average 1.5 million barrels of oil per day. Start up of the GHX-1 facilities in late 1990 will alleviate some of the gas overload. The producers are already studying a second project, GHX-2, which would boost the gas handling capacity in the field to about 7.5 billion cubic feet per day.

Start-up of the GHX-1 project (and the potential for the GHX-2 project) will help slow the decline of oil production at Prudhoe Bay. If additional gas handling facilities are not installed, the decline will be much more rapid than currently anticipated. In relative terms, more and more gas will be produced along with each barrel of oil as oil production continues over the years. If this additional gas cannot be processed and reinjected, the oil production rate will have to be cut back even further.

Expansion of the Prudhoe Bay field water handling facilities is also underway. Major construction projects are planned for 1990 to boost water handling capacity. These improvements will also help to keep the oil production decline rate from rapidly escalating.

Even with these major gas and water handling improvements, the oil production rate will continue to drop. Facility and pipeline down time is increasing year to year as corrosion and mechanical wear take their toll. The TAPS pipeline required significant maintenance and repair in 1989,

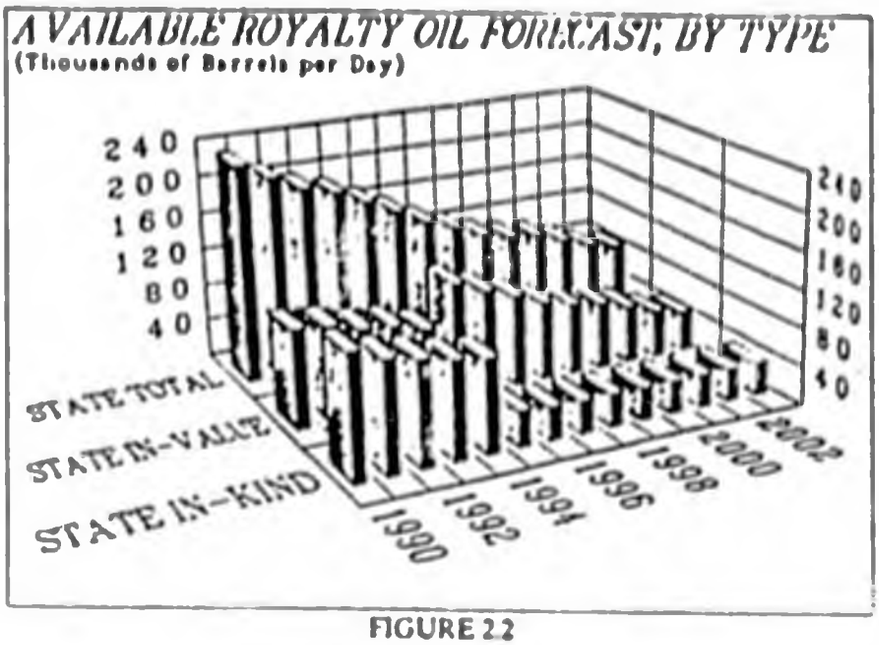


FIGURE 22

and operators plan major corrosion related work for 1990, including the replacement of a nine-mile segment of the TAPS line.

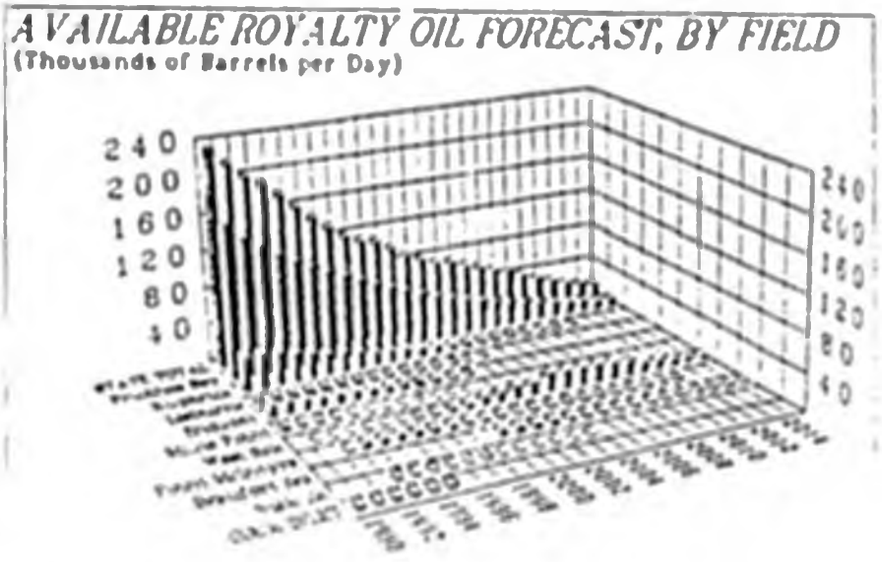
Infill drilling and development of peripheral drill sites continues in the Kuparuk River field. In addition, lessees will expand an enhanced oil recovery project (miscible gas injection) in the field. Supplies of sufficient volumes of miscible gas injectant limit the area in the field that can be affected at any one time.

Exploration Activity

Exploratory drilling activity in 1989 showed a marked increase over the past few years. On the North Slope, primary operations were onshore drilling south of the Kuparuk River Unit and in the Point McIntyre/Gwydyr Bay area. Offshore in the Beaufort Sea, Chevron's Karluk #1 was the only exploratory well completed. In the federal OCS portion of the Beaufort Sea Amoco completed its Belcher #1 well. Meanwhile, in the Chukchi Sea, Shell was active drilling one well and starting two others.

South of the Kuparuk River Unit, three lessees (BP, Texaco and Unocal) conducted drilling operations in 1989, and Texaco and BP have acquired permits to drill additional wells in the area. No results have been released for those wells drilled in 1989. In the Point McIntyre area, ARCO drilled three wells and announced a major oil discovery. Press reports stated that the reservoir may hold up to 300 million barrels of recoverable oil. Because of the reservoir's close proximity to the existing Prudhoe Bay/Lisburne infrastructure, development of the Point McIntyre reservoir should proceed rather quickly. The reservoir could be producing as early as 1992. ARCO also drilled an exploratory well just west of the Point McIntyre area but did not release any results from that well. Three more delineation wells are scheduled for the Point McIntyre area this winter as well as one more well immediately west of that area.

FIGURE 23



In the Duck Island/Endicott area, BP is conducting a long term production test at its Sag Delta #9 location and is planning to drill an exploratory well (Sag Delta #12) just southwest of the Endicott reservoir. ARCO plans to drill at least two delineation wells in the Kuparuk River Unit this winter and one well in the Hemi Springs Unit area. In addition, ARCO commenced drilling of the Stinson well #1 offshore in the Camden Bay area in the fall of 1989.

Numerous exploration activities are scheduled for 1990. In addition to the planned wells mentioned above, Shell intends to return to the Chukchi Sea, Amoco has a well approved for the eastern Beaufort Sea Outer Continental Shelf, Exxon has a well planned for the Point Thomson Unit, Conoco has a well planned in the Mikkelson Bay area and ARCO has a well planned in the Kavik area. Overall, the pace of exploratory drilling activity on the north slope is encouraging for 1990.

In the Cook Inlet area, remedial well work and infill drilling at currently producing fields continue at a good pace. While no new exploratory wells were drilled in 1989, collection of seismic data continued and lessees plan up to four exploratory wells in 1990. The recent sales or trades of lease interests and operatorships in the Cook Inlet area have resulted in better lease positions for certain companies, which are now planning new exploration activities. In addition, leases issued in the early 1980s are about to expire; some additional drilling activity is anticipated as these leases approach the end of their primary term.

Anchorage · *Star of the North*
Chamber of Commerce

ANCHORAGE CHAMBER OF COMMERCE
1992 Legislative Priorities
January 24, 1992

Anchorage Chamber of Commerce Mission
Make Anchorage a better place to live, work and do business profitably through the promotion of economic, civic and social development of our city.

437 E. Stree[redacted]72-2401

ANCHORAGE CHAMBER
LEGISLATIVE PRIORITIES

STATEWIDE AND FEDERAL ISSUES

The Anchorage Chamber of Commerce recognizes the need to support legislation and issues that are of Statewide benefit. The following is a list of Statewide/Federal issues and legislation that the Chamber supports for study and/or passage.

1. Finding Solutions to the Fiscal Gap (see attached)
   a) No new state capitol building in Juneau/sell the land
   b) Study privitization opportunities
   c) Study cap on dividends
   d) Don't spend the undistributed income from the Permanent Fund this year

2. Active promotion of the opening of ANWR and other Alaska resource development opportunities
3. Continue study of State Legislative term limits
4. Federal Term Limits by U.S. Constitutional Amendment as authorized by 38 states.
5. Legislative session limit to 90 days
6. Constitutional Amendments By Initiative
7. Support Congressional delegation as needed to keep Alaska Military facilities open and at current or greater levels of personnel
8. Crime Related Issues/Legislation (see attached)

- Support current funding level of violent crime compensation
- Continued pressure on the court system to prioritize compensation from convict to victim
- State conspiracy law
- SB 192-State seizure in drug crimes
- HB102- Legal intoxication levels
- Parental responsibility legislation
- HB101-Juvenile Waiver
- Review of the juvenile justice system and implementation of boot camps for juvenile offenders
- Statute of limitations for sexual assault offenders
- Tougher probation follow-up
- Prosecutor appeal of sentencing
- Jail overcrowding

ADDRESS OF SENATOR TED STEVENS

TO THE 17TH ALASKA STATE LEGISLATURE, SECOND SESSION

JUNEAU, ALASKA

THURSDAY, FEBRUARY 13, 1992

1991 WAS A MEMORABLE YEAR. THE COLD WAR ENDED WITH THE APPARENT COLLAPSE OF COMMUNISM. WITH THE UNITED NATIONS, WE FOUGHT AND WON A WAR IN THE PERSIAN GULF TO PROVE THAT NAKED AGGRESSION WOULD NOT RULE IN THE POST-COLD WAR WORLD.

THEN, THE NATION ENTERED A RECESSION THAT WE STILL ARE STRUGGLING TO OVERCOME. IT WAS ALSO A YEAR OF CHANGE FOR ME. I SUCCEEDED IN A PERSONAL BATTLE AGAINST PROSTATE CANCER. I'M DEEPLY GRATEFUL FOR THE PRAYERS AND SUPPORT THAT ALASKANS, INCLUDING MANY OF YOU IN THIS CHAMBER, PROVIDED MY FAMILY AND ME DURING THAT DIFFICULT TIME. IT'S THE SORT OF EXPERIENCE THAT TEACHES WHAT IS REALLY IMPORTANT IN LIFE.

AMERICA'S CHALLENGES ARE ALSO ALASKA'S CHALLENGES.

THE NORTH PACIFIC FISHERY MANAGEMENT COUNCIL'S INSHORE-OFFSHORE ALLOCATION DECISION IS GOOD BIOLOGY AND SOUND ECONOMICS.

FACTORY TRAWLERS ARE EXTRAORDINARILY WASTEFUL IN HARVESTING GROUNDFISH. UP TO TWENTY-TWO PERCENT -- MORE THAN 189 MILLION POUNDS A YEAR -- OF THE POLLOCK HARVESTED BY FACTORY TRAWLERS GO OVER THE SIDE WITHOUT EVER BEING PROCESSED. SHOREBASED TRAWLERS DISCARD ONLY ABOUT ONE PERCENT.

IN ADDITION, FACTORY TRAWLERS ALSO WASTE INCIDENTALLY CAUGHT SPECIES -- AT LEAST ONE HUNDRED AND TWENTY FOUR THOUSAND HALIBUT AND TWENTY THOUSAND CHINOOK SALMON. SHORESIDE PLANTS AND THE VESSELS SUPPLYING THEM USE THE RESOURCE MORE EFFECTIVELY AND PROVIDE MORE JOBS AND PAY TAXES TO COASTAL COMMUNITIES.

FULL UTILIZATION OF HARVESTED FISH MUST BE THE

RALLYING CRY OF ALASKANS IN THE 1990'S JUST AS AMERICANIZATION WAS IN THE 1980'S. IT IS AN ISSUE ON WHICH WE CAN JOIN FORCES WITH NATIONAL ENVIRONMENTAL GROUPS.

FACTORY TRAWLERS HAVE HIRED THE MOST AGGRESSIVE LOBBYISTS IN WASHINGTON TO DEFEAT THE COUNCIL'S POSITION. THOSE LOBBYISTS WORK ON ADMINISTRATIVE AGENCIES AS WELL AS CONGRESS.

THE COUNCIL IS RECONSIDERING INDIVIDUAL FISHING QUOTAS. THE IFQ CONCEPT MAY HAVE SOME MERIT BUT I HOPE THAT THE COUNCIL WILL FIND WAYS TO INCLUDE, IN A MORE MEANINGFUL FASHION, THE YOUNG MEN AND WOMEN WHO PUT THEIR LIVES AT RISK WORKING IN COMMERCIAL FISHING -- WE NEED A SYSTEM THAT NEW GENERATIONS OF ALASKANS CAN AFFORD TO ENTER AND DOES NOT ALLOW ANY GROUP TO CONTROL OUR FISHERY BY AGGREGATING IFQs.

RESOLVING THE SUBSISTENCE CONTROVERSY IS NECESSARY TO PROTECT ALASKA'S ABILITY TO MANAGE UPLAND GAME, SALMON AND OTHER FISH IN STATE WATERS.

UNLESS WE ACT SOON, BY THE END OF THE YEAR THE FEDERAL GOVERNMENT WILL BE MANAGING ALL FISH AND WILDLIFE -- INCLUDING OUR SALMON FISHERIES -- UNDER COURT ORDER.

THERE IS ONLY ONE SOLUTION; WORKING TOGETHER TO RESTORE UNIFIED STATE MANAGEMENT OF ALL FISH AND GAME.

THE GOVERNOR'S SUBSISTENCE PLAN IS A STEP IN THE RIGHT DIRECTION. I BELIEVE A CONSTITUTIONAL AMENDMENT IS REQUIRED WHILE THE GOVERNOR BELIEVES THE ALASKA LANDS ACT MUST BE CHANGED.

IF THE USER GROUPS -- AFN, UFA, AND THE ALASKA OUTDOOR COUNCIL -- CAN COME TO SOME CONSENSUS ON A PLAN, I AM WILLING TO ASK CONGRESS TO CONSIDER ADJUSTMENTS TO ANILCA IF YOU AND THE GOVERNOR ARE WILLING TO PRESENT A CONSTITUTIONAL AMENDMENT TO THE VOTERS OF ALASKA. IF WE CANNOT COME TO SOME AGREEMENT HERE AT HOME, EVERYONE EXCEPT DIEHARD OPPONENTS OF ALL HUNTING AND FISHING WILL LOSE.

MANY OF YOU HAVE RIGHTFULLY EXPRESSED CONCERN ABOUT THE POTENTIAL IMPACT OF REDUCED DEFENSE SPENDING AND FORCE REDUCTIONS ON ALASKA.

IN MY JUDGMENT, AS THE UNITED STATES MOVES TO FILL THE POWER VACUUM CAUSED BY THE DEMISE OF THE SOVIET UNION, ALASKA'S STRATEGIC LOCATION SHOULD GET EVEN GREATER RECOGNITION BY PENTAGON PLANNERS.

EVEN SO, IT'S GOING TO BE A BUMPY RIDE OVER THE NEXT FEW YEARS AS RECONFIGURATION AND REDEPLOYMENT OF OUR FORCES WORLDWIDE CONTINUES.

FRANK MURKOWSKI AND I CAME HOME LAST WEEK TO SEEK THE ADVICE OF ALASKANS ABOUT PURSUING ANWR THIS YEAR. THEY URGED US NOT TO PRESS ANWR ON THE ENERGY BILL UNLESS WE COULD GET AN UP OR DOWN VOTE THAT WOULD TEST OUR TRUE STRENGTH. AS FRANK EXPLAINED YESTERDAY THAT WAS IMPOSSIBLE.

DON AND FRANK CONVINCED THE PRESIDENT TO INCLUDE AN ANWR PROVISION IN THE PRESIDENT'S ECONOMIC GROWTH PROPOSAL WHICH IS NOW BEFORE CONGRESS. AS A JOBS

ISSUE, ANWR MAY HAVE A BETTER CHANCE, BUT MAKE NO MISTAKE: IT WILL STILL BE AN UPHILL BATTLE.

TO WIN THIS FIGHT, WE MUST LAY THE GROUNDWORK NOW. CREATING AN ANWR BLUE RIBBON COMMISSION LIKE THE ONE THAT HELPED US PROTECT OUR INTERESTS IN THE ALASKA LANDS DEBATE IS ONE STEP TO CONSIDER. ANOTHER IS TO CONSIDER ALLOWING ALASKANS TO EARMARK UP TO $50 OF THEIR PERMANENT FUND DIVIDEND CHECK TO FUND SUCH A COMMISSION AND THE NATIONAL GRASSROOTS WORK THAT WILL HAVE TO BE DONE TO PREVAIL. IF ALASKANS DON'T TAKE DECISIVE ACTION TO OPEN ANWR, THE FUND'S INCOME WILL SOON HAVE TO BE DEVOTED TO BASIC GOVERNMENT SERVICES, AND THE DIVIDEND PROGRAM WILL BECOME AN HISTORICAL FOOTNOTE. IF ANWR IS OPENED, THE CONTRIBUTIONS BACK TO THE FUND COULD EXCEED $25 BILLION -- A RETURN ON INVESTMENT THAT NOT EVEN DAVE ROSE COULD MATCH.

PROTECTING ALASKA'S FAMILIES IS A CRUCIAL CHALLENGE ON BOTH THE FEDERAL AND STATE LEVEL. THE

PRESIDENT HAS ANNOUNCED A BOLD NEW INITIATIVE THAT WOULD DEDICATE $100 BILLION FOR OUR NATION'S HEALTH CARE SYSTEM, INCLUDING THE KIND OF PREVENTATIVE CARE THAT LED TO EARLY DETECTION OF MY CANCER.

THERE ARE SOME WHO SAY THAT'S NOT ENOUGH, AND AS A RESULT, THERE ARE 498 HEALTH CARE REFORM BILLS PENDING IN CONGRESS -- ALMOST ONE PER MEMBER! IT WILL, NO DOUBT, BE A LONG, HOT SUMMER.

WE HAVE MADE PROGRESS IN IMPROVING HEALTH CARE IN RURAL ALASKA, BUT WE MUST ADDRESS THE NEEDS OF URBAN ALASKANS, TOO. I HOPE AS FEDERAL HEALTH CARE REFORM UNFOLDS WE CAN WORK TOGETHER TO AVOID DUPLICATION AND ENSURE THAT EVERY ALASKAN HAS ACCESS TO BASIC HEALTH CARE.

WHILE WE HAVE MADE SOME STRIDES IN THE WAR AGAINST DRUGS, DRUG ABUSE AMONG ALASKANS CONTINUES TO BE A PROBLEM. AT A RECENT CONFERENCE OF ALASKANS INVOLVED IN DRUG ABUSE PREVENTION, TREATMENT, AND ENFORCEMENT, THEY TOLD ME THERE WERE TWO THINGS YOU

COULD DO TO HELP.

(1) MODIFY ALASKA'S ASSET FORFEITURE STATUTE SO STATE LAW ENFORCEMENT CAN MORE EFFECTIVELY SEIZE THE ASSETS OF DRUG PUSHERS.

(2) ESTABLISH A STATE CONSPIRACY STATUTE TO STRENGTHEN THE HAND OF THOSE FIGHTING THE DRUG PUSHERS PREYING ON ALASKA'S FAMILIES.

WHILE GENERALLY ALASKANS ARE AMONG THE MOST HIGHLY EDUCATED PEOPLE IN THE COUNTRY -- A TESTIMONY TO OUR TEACHERS AND OUR STUDENT LOAN PROGRAM -- MANY RURAL ALASKANS LAG BEHIND. I WILL JOIN WITH YOU AND OTHER ALASKANS -- PARTICULARLY THE PARENTS AND TEACHERS INVOLVED IN OUR EDUCATIONAL SYSTEM -- TO MAKE SURE THAT THE NEW NATIONAL EDUCATION LEGISLATION WORKS IN ALASKA.

ONE OF THE BEST WAYS TO PROTECT FAMILIES IS TO PROVIDE MEANINGFUL WORK FOR PARENTS, AND ONE OF THE KEYS IS EDUCATION. ALASKA'S NEW JOB CORPS CENTER SUFFERED A TEMPORARY SETBACK AGAIN, WHEN THE

DEPARTMENT OF LABOR ANNOUNCED THAT IT WOULD NOT RELEASE CONSTRUCTION FUNDS FOR THE PROJECT. FRANK, DON, AND I INTEND TO MEET WITH SECRETARY OF LABOR LYNN MARTIN TO MAKE OUR OPPOSITION CLEAR.

A NEW ERA HAS BEGUN IN THE WORLD -- ONE THAT WILL SHAPE THE LIFE OF OUR NATION AND STATE IN WAYS WE CAN'T EVEN IMAGINE NOW. THE CHALLENGES ARE MANY, BUT I CONTINUE TO HAVE FAITH IN THE ABILITY OF ALASKANS TO MEET THEM IN INNOVATIVE WAYS. YOU AND I HAVE BEEN ENTRUSTED BY THE PEOPLE OF ALASKA WITH THE TASK OF DEVISING WAYS TO MEET THOSE CHALLENGES.

RATHER THAN SPEND A LOT MORE TIME DISCUSSING WHAT THE CONGRESSIONAL DELEGATION IN PARTNERSHIP WITH ALASKANS WAS ABLE TO ACCOMPLISH, OR REPEAT WHAT YOU'VE ALREADY HEARD FROM SENATOR FRANK MURKOWSKI OR CONGRESSMAN DON YOUNG, I'LL NOW ASK THE PAGES TO DISTRIBUTE A REPORT, WHICH DISCUSSES THE IMPORTANT EVENTS OF THE LAST SESSION OF CONGRESS IN MORE DETAIL.

THANK YOU AGAIN FOR ALLOWING ME TO VISIT WITH YOU TODAY. I LOOK FORWARD TO WORKING WITH YOU THIS YEAR, AND I'D BE GLAD TO TAKE ANY QUESTIONS YOU MIGHT HAVE.

April 8, 1991

Overview of the 1991 Arctic National Wildlife Refuge Recoverable Petroleum Resource Update

Summary of Findings

The 1991 update of recoverable petroleum resources in the 1987 Arctic National Wildlife Refuge, Alaska, Coastal Plain Assessment, also known as the 1002 Report, makes a considerable contribution to the knowledge and understanding of the petroleum geology of the 1002 area of the Arctic National Wildlife Refuge (ANWR). This study reaffirms most of the conclusions and estimates made in the 1002 Report, and increases the level of confidence that ANWR is part of the North Slope oil province. This is demonstrated by the increase in the marginal probability of economic success from 19 percent in the original assessment to 46 percent in the current assessment. The increase in marginal probability means that ANWR has a higher potential for oil discovery. The overall Minimum Economic Field Size (MEFS) for the 1002 area has been lowered from about 0.44 billion barrels of oil (BBO) to about 0.40 BBO. The mean resource estimate has increased from 3.23 to 3.57 BBO.

Introduction

The original recoverable resource assessment was included in the 1002 Report, published in 1987. It was well received in reviews of the report by industry and the scientific community, but, as was its intent at that time, was considered conservative. The intent of Section 1002(h) of ANILCA was to give the Secretary of the Interior sufficient information to make an informed decision for his recommendation to Congress pertaining to oil and gas leasing in the 1002 area. The 1991 assessment was prepared as a part of routine updating of resource assessments that takes place every 2 to 5 years and that reflects new and reinterpreted geological data, state-of-the-art engineering, current tax provisions, and updated economic data.

Because Congress intended for the 1987 assessment to be conducted with as little impact on the 1002 area as possible, they did not authorize the drilling of test wells. Therefore, the only sources of information available for the 1002 study were records from wells drilled in the surrounding area and about 1,300 line miles of seismic reflection data shot by a consortium of 25 companies on an approximate three-by-six mile grid in the 1002 area. Selected gravity readings collected by industry from the 1002 area and the results of surface geologic work conducted by in-house and various outside sources in and around the coastal plain were also available and beneficial to the study. With this amount of information and given the timeframe for completion of the study, a conservative approach was taken in order not to overestimate the economically recoverable hydrocarbon potential in the area.

Since the 1002 Report was completed in 1987, the BLM in Alaska has obtained access to information from four wells drilled near or adjacent to ANWR. They are Tenneco's Aurora No. 1, Unocal's Hammerhead No. 1, and Shell's' Corona No. 1, all located offshore from ANWR, and Unocal's Leffingwell No. 1, located onshore West of ANWR (figure 1). The BLM also obtained approximately 800 line miles of the original seismic data that was reprocessed by

industry to enhance the resolution of seismic reflectors of the shallower Brookian sequence rocks and to help increase the understanding of this sequence. Additionally, some offshore seismic lines near ANWR became available. These new data were used in the current analysis. In addition, an in-house study of the petroleum geology of northeastern Alaska through the Mackenzie Delta in western Canada enhanced the understanding of the regional geology. Surface samples of potential reservoir rocks also were analyzed to assess reservoir parameters. Furthermore, the 1991 assessment utilized a LANDSAT analysis of the bedrock geology of the "bulge" of the mountain front south of the 1002 area.

In August 1990, the Department of Energy's (DOE) Idaho National Engineering Laboratory (INEL) issued a draft study of oil and gas development on the North Slope. This was combined with an in-house analysis and a survey of major companies operating on the North Slope to update the engineering and costing of ANWR development. Updated DOE forecasts of oil prices were also included in the analysis.

Geological and Geophysical Analysis

The new and reinterpreted data resulted in an analysis that, although not vastly different from the 1002 report, gave the BLM a greater degree of confidence in their original recoverable resource assessment of 1987, and also increased their knowledge and understanding of the complicated petroleum geology which exists in and around the 1002 area.

The geology studies and seismic information suggested the necessity of updating correlations of the pre-Ellesmerian basement rocks across the area. Elements of these rocks were important to almost all of the previously mapped prospects. The BLM developed a more detailed description of the depositional systems involved in ANWR stratigraphy. This was important in the Brookian sequence rocks as to their location, extent in the subsurface, and relationship to similar rocks in the Canadian Beaufort/Mackenzie Delta area which have successfully tested and produced oil and gas. The new data provided a higher degree of confidence in determining the nature of geological plays described in the original 1002 Report. This is important to the definition of drilling objectives in the mapped prospects.

The geophysical analysis incorporated the new well data, gravity data, and reprocessed seismic data obtained during the 1983-84 and 1984-85 seasons. The reprocessed seismic data provided better resolution to the seismic reflectors defining the shallow (Brookian) part of the section. This allowed the BLM to map several structural closures within this sequence. These prospects were delineated within the area previously mapped as trends (figure III-10 in the 1002 Report). Most of these new prospects are small and either would not be developed or would be developed in conjunction with the prospects mapped in the 1002 Report, over which the new prospects lie. However, in one case, the prospective target is a stratigraphic prospect of some significance. The gravity data correlated well with the seismically mapped structures of the 1002 area, helping to confirm this aspect of the 1987 Report. Geophysical information from the new wells around ANWR was useful for fine-tuning some of the sonic velocities that were used in the original mapping of the 1002 area. The velocity corrections provided more accurate depths to some of the prospects and also supported the reassessment of prospective reservoirs (drilling objectives)

in some of the prospects.

PRESTO Model Inputs

The PRESTO (Probabilistic Resource ESTimates, Offshore) model was used to develop resource estimates. One or more prospective targets were defined for each identified prospect based on the potential for reservoir rocks. Reservoir parameters consisted of risks of no hydrocarbons and probability distributions of the physical characteristics of targets within prospects. Three levels of risk were defined: the risk that no recoverable hydrocarbons existed in the area, in each prospect, and in each prospective target in each prospect. Since gas was assumed to be uneconomic, only four parameters were defined for each target: the probability that the resource is oil (rather than gas), and distributions of productive acreage (acres), pay thickness (feet), and oil recovery factor (bbls/acre-foot). Engineering and economic input for PRESTO consisted of specifying minimum economic field sizes. Minimum recoverable resource sizes were set for each of the prospects.

Reservoir Parameters

The 1991 PRESTO inputs of reservoir parameters evolved from updating the ANWR geologic and geophysical database described above. The changes included the addition of a new stratigraphic prospect mapped in the Brookian sequence, and other new prospects associated with the previously identified prospects. Some PRESTO inputs were derived by an iterative process. After each PRESTO run, the sampled means of the geologic parameters were reviewed to ensure that they accurately modeled the database of the regional geologic parameters. Iterative runs were necessary in cases where choices of the PRESTO input parameters were restricted. In these cases, a decision had to be made on which available input choice most accurately modeled the database of regional geological parameters. These updates resulted in revisions of geological risks, play assignments, and the distributions for unit thicknesses, oil recoveries, and productive acres (or trapfill).

Geologic Risk. Geologic risk played a major part in a PRESTO assessment and was the most subjective of the input parameters. In the 1987 resource assessment, ANWR was studied as a separate basin and considered a frontier area. Using other frontier areas as analogs, a rule-of-thumb approach was used in determining individual prospect risks. No prospect was considered to have a risk of less than 90 percent, i.e. no prospect could have a probability of success of greater than 10 percent. This approach assured that the PRESTO-generated probabilities of economic success would be consistent with other frontier onshore areas of the United States. However, reviews of the ANWR assessment by the National Academy of Science and the Department of Energy suggested that this assumption led to conservative resource estimates and unrealistically low probabilities of success.

The current resource update used the regional petroleum geology study, including the additional well data and the interpretation of reprocessed seismic data, to develop an improved understanding of the stratigraphic framework of the 1002 and surrounding area. With this information, it appeared more appropriate to consider the 1002 area as part of the North Slope

oil province, rather than as a rank wildcat frontier area, with ANWR the middle section between the Prudhoe Bay area complex and the discoveries in the Mackenzie Delta area (figure 2). In the North Slope province, hydrocarbons were thought to have been generated and trapped by a variety of mechanisms with the probability of an oil or gas show being very high. Therefore, the probability of a new oil or gas discovery under these conditions was considerably greater than reported in 1987. Consequently, the PRESTO inputs and the geologic prospect risk developed in 1991 reflected this situation, resulting in lower prospect risks and area risk. Each prospect in the 1991 assessment update was studied individually, and each had a risk computed for it derived from the USGS/BLM play risks and the BLM seismic risk. This allowed PRESTO to calculate a conditional economic probability for each prospect and eliminated the previous constraint.

As in the 1987 assessment, this analysis assumed a dependence between prospects. Assuming complete independence implies that all of the prospects in the area would be tested in the course of exploration without incorporating the acquired geologic information that became available as the exploration proceeded. Observations of drilling activities on the North Slope and the current knowledge of the geology of ANWR, resulted in an agreement with the 1987 assessment that only 4 to 6 prospects would be tested in the 1002 area to determine its economic viability. Prospects tested later would be dependent on the results of the first tests.

Play Assignments. Plays were extended or reassessed based on well data, seismic data and the regional geology study; potential reservoirs within prospects were then updated.

Unit Thickness. Adjustments were made to several prospects based on offshore well data and a regional geology study.

Oil Recovery. The oil recovery factor calculations were in part based on the gas-oil ratio (GOR). Literature research showed that the GOR used in the original assessment was conservative and not representative of those found on the North Slope. Oil recovery was recalculated using a more accurate figure for GOR.

Productive Acres or Trapfill. Trapfill is the percentage of the maximum areal extent of the trap that contains recoverable oil or gas. Given the maximum acreage for a trap, the trapfill can be converted to a distribution of productive acres. There is very little information available regarding trapfill. In the 1987 1002 assessment of in-place resources, a play analysis was conducted in which trapfill was represented by a seven point distribution. The assessment of recoverable resources, however, required a prospect analysis and utilization of the PRESTO model. Since the seven-point distribution is not available in PRESTO, a triangular distribution for trapfill was substituted for the calculation of recoverable resources in the 1987 report. However, the 1991 update used a lognormal distribution for trapfill. With the current uncertainty regarding trapfill, it was judged that a lognormal distribution better describes field size distributions found in nature.

Minimum Economic Field Size Analysis

Combining the Minimum Economic Field Size (MEFS) with the reservoir parameters in the PRESTO model produces the economically recoverable resource estimates. The inputs into the MEFS analysis can be grouped into four categories: engineering and costs, taxes, macroeconomics, and reservoir characteristics. The result of the MEFS analysis was a slight lowering of the MEFS. Each prospect has its own MEFS, but overall the MEFS decreased from about 440 million barrels to about 400 million barrels. This figure is applicable to western prospects. The eastern prospects, needing a longer pipeline to reach TAPS, required about 550 million barrels as opposed to the 660 million barrels in the 1002 Report.

The MEFS analysis for the 1002 Report was described in the Appendix, Economics of Oil and Gas Production from ANWR for the Determination of Minimum Economic Field Size, by Young and Hauser (1986). In 1990, the Department of Energy's (DOE) Idaho National Engineering Laboratory (INEL) conducted an extensive literature review, convened public hearings, and collected industry comments for a study of North Slope oil and gas development potential. This included an examination of potential development in the 1002 area. The draft of this study was published in August 1990. The BLM Alaska State Office reviewed this report, compared it with internal information, and followed it with a survey of companies operating on the North Slope to resolve inconsistencies and obtain industry comments on specific data and conclusions presented in the DOE/INEL draft report.

Engineering and Costing. Engineering on the North Slope since the 1002 Report analysis has been more evolutionary than revolutionary. The 1987 1002 analysis had been modeled after the Kuparuk field development. The 1991 analysis incorporated more recent development such as at the Endicott and Milne Point fields which have demonstrated further refinements such as smaller pad sizes that slightly lowered costs and decreased environmental impacts. Endicott is an offshore field developed on gravel islands where space is limited; Milne Point is a small field north of the Kuparuk field.

The major engineering and costing assumption incorporated into this analysis is the stand-alone assumption. This means that development of any prospect must cover all the costs of facilities and transportation requirements by itself. In other words, there is no cost sharing consideration for multiple field development, either simultaneous or sequential. This assumption was used in the 1002 Report. The DOE/INEL study reported tests of some hypothetical examples of multiple small discoveries and noted the resultant impact on minimum economic field sizes. This required them to make assumptions as to which prospects and under what conditions the prospects could share costs, which generally are unreliable and tend to be very subjective. The 1991 update focused on fields with sufficient significance to justify initial development in the 1002 area. Although smaller fields would be economic as a result of this development and would likely be developed later, they are not included in the resource assessment. The engineering and costing focused on minimum economic field sizes since PRESTO only requires the use of this threshold field size.

Exploration assumptions did not change from the 1002 Report: one exploration well drilled into the crest of the prospect the year after leasing, followed by two delineation wells each of the next

3 years into the deepest parts of the prospect. Since there was little recent data available on North Slope exploration, particularly in remote areas, the DOE/INEL study estimated these costs based on the 1002 Report exploration costs. However, BLM's later survey of industry indicated that this estimate was too low. This resource assessment used a cost function based on the industry survey and was consistent with the cost of drilling the KIC well on Native lands within the 1002 area. The BLM will continue to gather engineering and cost information related to new technology, and will consider them in any future updates.

The DOE/INEL study contained an extensive review of production facilities and their costs. The facilities are similar to those used in the 1002 Report, and take into account improvements in the footprint and efficiency. The DOE concentrated on the cost savings from facility sharing. While this is of interest with regard to later development of smaller adjacent fields, the present resource assessment is primarily concerned with initial development. The DOE/INEL estimated a cost surcharge of 15 percent for the first development in a remote area. The BLM's industry survey concurred with DOE's estimates for facilities costs.

The engineering of development drilling has changed little from the 1002 Report. In both the DOE/INEL study and this resource assessment, the number of wells required is still calculated as before. The DOE/INEL hypothesized different categories of development based on field size. For fields relevant to the MEFS analysis, DOE used the same development schedule as the 1002 Report, i.e., 6 years of development drilling with production starting in the 5th year of development and production peaking the year after completing the development. The BLM's industry survey strongly indicated that this was too long as it should be only 5 years of drilling with production starting in the 5th year and peaking the following year. The costs of development provided more disagreement. The DOE estimated a cost function for development drilling based on actual costs in existing fields, demonstrating how costs have declined dramatically over the past decade. However, DOE felt that these costs would not apply to a remote area such as the 1002 area and revised the 1002 Report cost functions, essentially eliminating the cost reductions gained in the past decade. The DOE then applied a learning curve to reduce costs by one-half over 5 years. Industry strongly disagreed with these estimates, indicating that the latest advances used at Endicott and Milne Point fields would also apply to 1002 developments. Costs would initially be somewhat higher than in existing fields, but would quickly drop as infrastructure was built up and the operators became familiar with ANWR. Thus, at depths to fifteen thousand feet, the estimated costs were much less than the DOE costs, in some cases were as low as one-half the DOE cost. At deeper depths costs increased rapidly, approaching DOE's costs at around twenty thousand feet.

Based on the DOE/INEL study and the concurrence of industry, the estimated production schedule was similar to that in the 1002 Report except that these small fields would have a 15 rather than a 12 percent annual decline. This assessment used two refinements in engineering that were introduced in DOE/INEL's North Slope study: using the increasing water cut and the decline in the number of active producing wells. Water cut is the percentage of fluid production that is water. As a field is depleted, the water cut increases. At the start of production, it is assumed that 40 percent of wells drilled are used for injection. As the reservoir gets depleted,

some production wells are converted to injection wells. The water cut is used in calculating operating costs, while the number of active producers is used in the severance tax calculation. Analyzing the existing fields on the North Slope, DOE obtained a more accurate representation of production costs based on total fluid production rather than oil production. Industry concurred with these costs and they were used in this resource assessment.

The DOE/INEL reviewed the three components of transportation costs; a pipeline from ANWR to TAPS, a tariff for using TAPS to Valdez, and tankering from Valdez to the lower 48. The TAPS tariff is comparable to the numbers in the 1002 analysis. This assessment used the same spreadsheet used by the State of Alaska to estimate future tariffs, including the costs of corrosion abatement and increased oil spill response capability. The DOE found that the average tanker cost was less than that used in the 1002 Report due to a higher proportion going to the West Coast rather than the Gulf Coast. The DOE did not have data to update the costs for the pipeline from the 1002 area to TAPS and thus used the function from the 1002 Report. However, industry strongly disagreed with this estimate. Based on their own internal studies of a pipeline from the 1002 area to TAPS, industry provided the lower cost estimates used in this resource estimate.

The stand-alone assumption and the facilities and ANWR pipeline costs are the primary factors for determining the MEFS. The development drilling costs also become a major factor for every deep, low yield prospect.

Taxes. Several changes have occurred in taxes since the 1002 analysis. The Federal tax code has changed but generally had little effect. Assuming development by a major oil company, the modification of the tax deductions is offset by the reduction in the corporate tax rate. The minimum tax provisions were assumed to have no impact. The State altered its severance tax by raising the tax for very large fields. Since this analysis is looking for the minimum economic field size, this change had only a marginal impact.

Macroeconomics. The macroeconomic assumptions covered four areas: discount rate, oil prices, the role of natural gas, and inflation. The discount rate used in this assessment was the same used by Young and Hauser for the 1002 Report, i.e., a real after-tax rate of 10 percent. The oil price scenario used was the DOE National Energy Strategy Reference Case. This resulted in a lower price schedule than that used in the 1002 Report, but was closer when taking into account the delay in opening the 1002 area of ANWR. Natural gas was still assumed to be uneconomic for purposes of estimating the MEFS due to the uncertainty of available transportation and the huge reserves already available on the North Slope. Although the gas eventually may be developed, the decision to develop the 1002 area in the next 10 years will not depend on the development of natural gas resources. Inflation is assumed to average four percent a year rather than the six percent used in the 1002 Report. This figure is comparable to inflation rates used in the DOE report and long range analyses by firms as DRI/McGraw-Hill. Since inflation was incorporated in cost and price escalation as well as the nominal discount rate, the impact on the MEFS was marginal. The decline in the price estimates was offset by the decline in the costs, resulting in the lower MEFS.

Reservoir Characteristics The reservoir parameters previously described were used in estimating the MEFS. For each prospect, a risk-weighted average oil recovery factor was calculated, conditioned on the existence of hydrocarbons in the prospect. In testing a resource size for the MEFS, the average recovery was used to calculate the number of acres required to contain oil. If the acres required exceeded the areal extent of the prospect, then the maximum productive acreage was used, increasing the recovery factor to that necessary to yield the tested resource size. The acreage in turn determined the number of wells needed to develop the prospect.

PRESTO III Analysis Results

The results of this new study show that at the mean, there are 3.57 billion barrels of conditionally economically recoverable oil resources for the 1002 area with a marginal probability of economic success of 46 percent. The large increase in the marginal probability was due to:

1. Adding a reservoir to some of the prospects which made their economic probability greater;

2. Increasing the number of mapped prospects;

3. No longer considering the 1002 area as a frontier area for oil exploration and not constraining the individual prospect probability of success; and

4. Having a slightly smaller economic field size.

Conclusion

Mineral assessment is a dynamic process. As new information becomes available, it will be necessary to review previous assumptions and models and, if necessary, make adjustments to previous assessments. The BLM has gained considerable experience and improved its expertise in analyzing the complicated foreland fold and thrustbelt type geology which exists in ANWR. The 1991 ANWR assessment update has reaffirmed the previous resource estimates and increased the confidence that these resources will be found. This confidence level is reflected in the increase in the marginal probability from 19 percent to 46 percent.

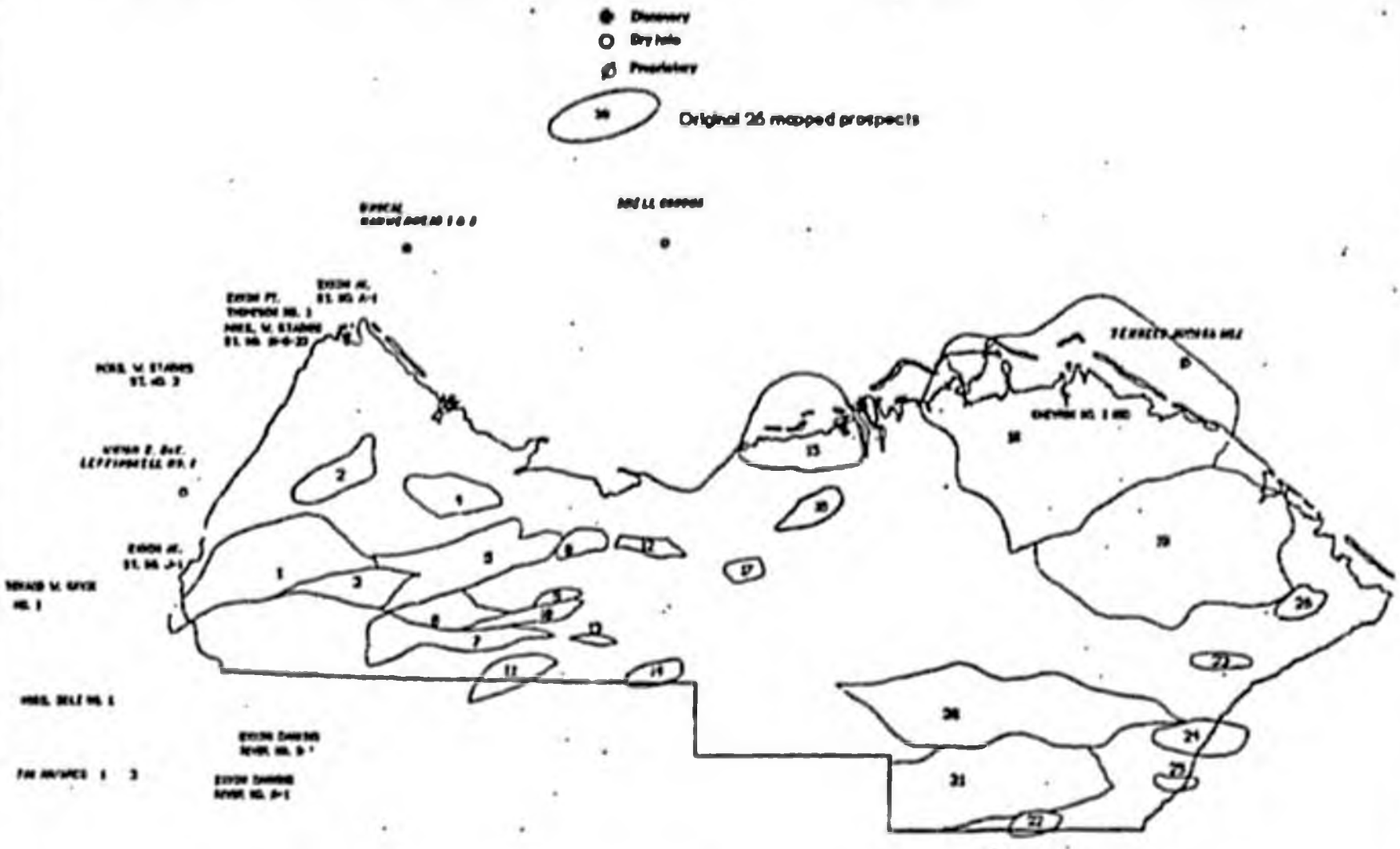


Fig. 1 Pertinent wells studied for 1990 ANWR Update

(Well locations approximate, KIC well not studied)

(Extracted from Banet, Foland, Lolla, 1990)

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MAJOR OIL / GAS DISCOVERIES

North Slope, Alaska and Mackenzie Delta, Canada

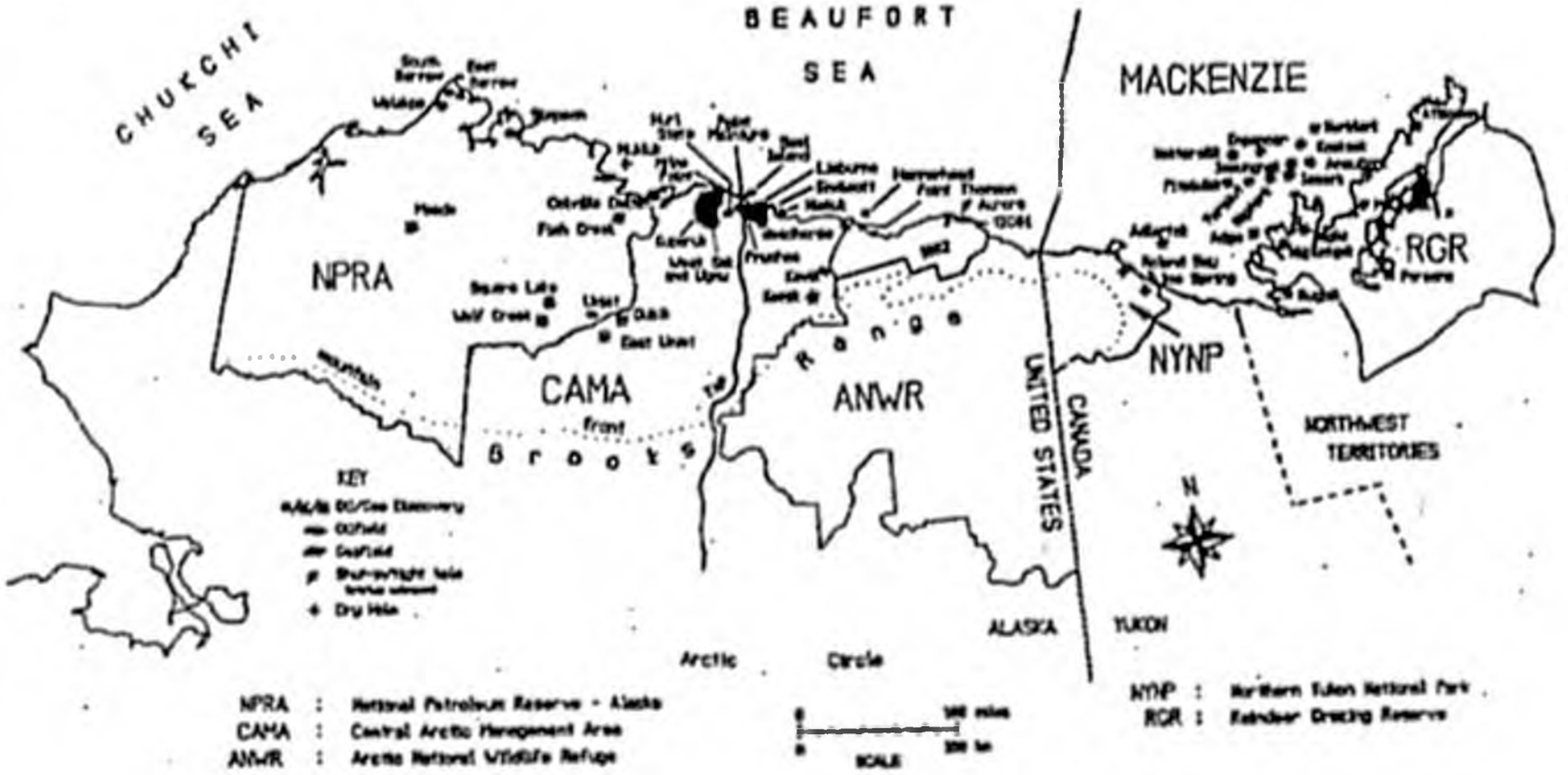

Fig. 2 Northern Alaska/Canada Oil & Gas discoveries

(From Banet, 1990, in press)

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House State Affairs Committee
Representative Gene Kubina, Chair

DATE: February 28, 1992

PLACE: Capitol Room 102

SUBJECT OF MEETING:

*HB 506 - Relating to PF Dividend Check-Off for ANWR Support
*HCR 51 - Relating to Organ and Tissue Donation Week
*HCR 52 - Relating to Alcohol-Related Birth Defects Awareness

NAME	REPRESENTING	BUSINESS/PERSONAL MAILING ADDRESS	ZIP	(H) PHONE	(W) PHONE	DO YOU WANT TO TESTIFY?		WHAT SUBJECT/ WHICH BILL?
Carol Reed	C/B.T DHSS High Risk Families Coalition	CDD - 3406 Glacier Hwy	99801	789-3567	586-1470	Y	N	HCR 52
Rod Mc.Urgent	Revenue				x 230	Y	N	HB 506
Bob STALNAKER	Retirement Systems				x4470	Y	N	SB 381
Tom Williams	PFD Division	Revenue			x2323	Y	N	HB 506
						Y	N	
						Y	N	
						Y	N	
						Y	N	
						Y	N	
						Y	N	
						Y	N	
						Y	N	

House State Affairs Committee
Representative Gene Kubina, Chair

DATE: February 28, 1992

PLACE: Capitol Room 102

SUBJECT OF MEETING:

CSSB 381 - Relating to Health Insurance Info for PERS Retirees
HB 404 - Relating to Deadline for Certain Candidates
HB 327 - Relating to Primary Elections

NAME	REPRESENTING	BUSINESS/PERSONAL MAILING ADDRESS	ZIP	(H) PHONE	(W) PHONE	DO YOU WANT TO TESTIFY?		WHAT SUBJECT/ WHICH BILL?
Paula Terrell	Sam Kaituka	P.O. Box V	99811		465 1200	(Y)	N	SB 381
						Y	N	
						Y	N	
						Y	N	
						Y	N	
						Y	N	
						Y	N	
						Y	N	
						Y	N	
						Y	N	
						Y	N	
						Y	N	