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**ANALYSIS OF HISTORICAL OIL AND GAS LEASE SALE
AND EXPLORATION DATA FOR ALASKA**

by

Richard W. Kornbrath



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**STATE OF ALASKA
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**DIVISION OF GEOLOGICAL & GEOPHYSICAL SURVEYS
IN COOPERATION WITH THE DIVISION OF OIL & GAS**

1995

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF GEOLOGICAL & GEOPHYSICAL SURVEYS

Tony Knowles, *Governor*

John T. Shively, *Commissioner*

Milton A. Wiltse, *Acting Director and State Geologist*

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ANALYSIS OF HISTORICAL OIL AND GAS LEASE SALE AND EXPLORATION DATA FOR ALASKA

by
Richard W. Kornbrath¹

INTRODUCTION

This report examines the relationship between competitive oil and gas lease-sale offerings and the success rate of subsequent exploration. In some past state lease sales, all the tracts offered were leased. However, in most state lease sales and in all the federal lease sales in Alaska, substantially fewer tracts have been leased than were offered. Of the tracts leased by the oil industry, virtually all are "explored," but to very different degrees; some tracts have been commercially developed, some have been drilled without success, and many have reverted back to the state without drilling.

To understand the potential impacts from exploration and development, specific activities and techniques that are generally used (or that may be contemplated) to locate and extract subsurface hydrocarbons must be considered. These possible activities should be viewed in the proper perspective by examining their frequency of occurrence and the likelihood that a given lease offering or an individual lease will undergo exploration drilling with a subsequent commercial discovery over the lifetime of the lease.

Northern Alaska and Cook Inlet are the dominant oil regions of the state (figs. 1 and 2), and account for most lease sale offerings. Historical lease sale data from state and federal sales in Alaska have been compiled by sale number, date, and region (tables 1-3). A complete database of all producing fields, known but undeveloped accumulations, and discoveries has been assembled and categorized by region, hydrocarbon type (oil or gas), date of discovery, and status (tables 4-9). A commercial well-log database containing all the exploration and development wells in the state has also been used to compile lists of the numbers and types of wells drilled in each region of the state. The data are summarized in tables 10-12 and figures 3 and 4.

THE EXPLORATION PROCESS

Exploration for oil and gas is often misinterpreted solely as the drilling of exploration wells. In fact, most exploration activities are conducted without ever drilling a new exploration well. The actual drilling of a well, when it does occur, is the culmination of a comprehensive

evaluation process that may take many years to complete and is reserved for those prospects with sufficient revenue-generating potential to offset the high costs of lease acquisition, drilling, and development. This analysis shows that few leases offered in competitive sales are ever drilled, and fewer yet are found to hold commercial quantities of hydrocarbons. Understanding this is critical to rationally weigh the benefits versus the financial risk of oil and gas exploration and to make rational land-use decisions. In actual process, "exploration" primarily entails highly technical subsurface mapping efforts conducted in oil-company offices; moreover, potentially "intrusive" activities such as drilling, field development, facilities construction, and product transportation are unlikely to occur on the vast majority of tracts being offered for lease.

The term "exploration," as it pertains to the search for commercial quantities of oil and gas, encompasses a broad range of techniques and activities developed by geoscientists to help detect and find hydrocarbons trapped in rocks beneath the earth's surface. These techniques and activities attempt to take advantage of different aspects of the generally accepted model used to explain the formation of hydrocarbon deposits in the subsurface.

Briefly, this geologic model recognizes source rock, reservoir rock, a seal, a trap, timing, and migration as the most important elements responsible for most hydrocarbon deposits. Source rocks (normally shales) are organic-rich, generally fine-grained rocks that have the capacity to generate hydrocarbons under certain subsurface burial temperatures and pressures. Reservoir rock (normally porous sandstone or limestone) refers to a rock type that has interconnected pore space capable of storing and then yielding liquid or gaseous hydrocarbons. Seal refers to the generally fine-grained rock type that forms an impervious barrier over a trap, preventing the further migration or escape of hydrocarbons. Trap or trapping mechanism describes the combination of elements (structural and/or stratigraphic) that result in particular geometries in subsurface reservoir rocks conducive to collecting and storing hydrocarbons. Finally, timing and migration describe the processes related to the subsurface movement (generally up-structure or updip), over time, of hydrocarbons after the time of formation of a subsurface trap.

The State of Alaska's Five-Year Oil and Gas Leasing Program establishes biennial lists of proposed lease-sale areas projected five years into the future. This lead time,

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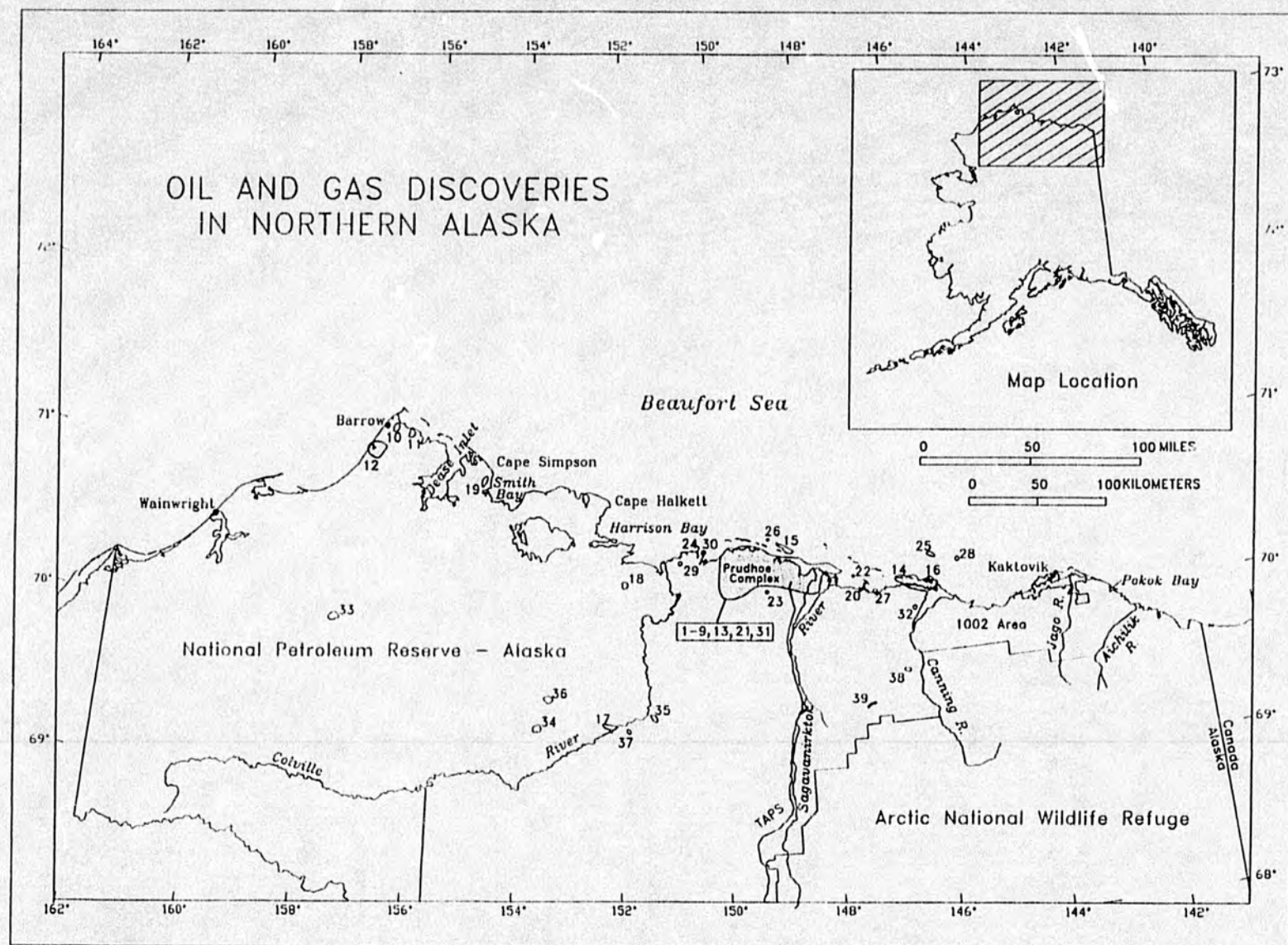


Figure 1. Oil and gas discoveries in northern Alaska. (The numbers by the discoveries are keyed to table 9.)

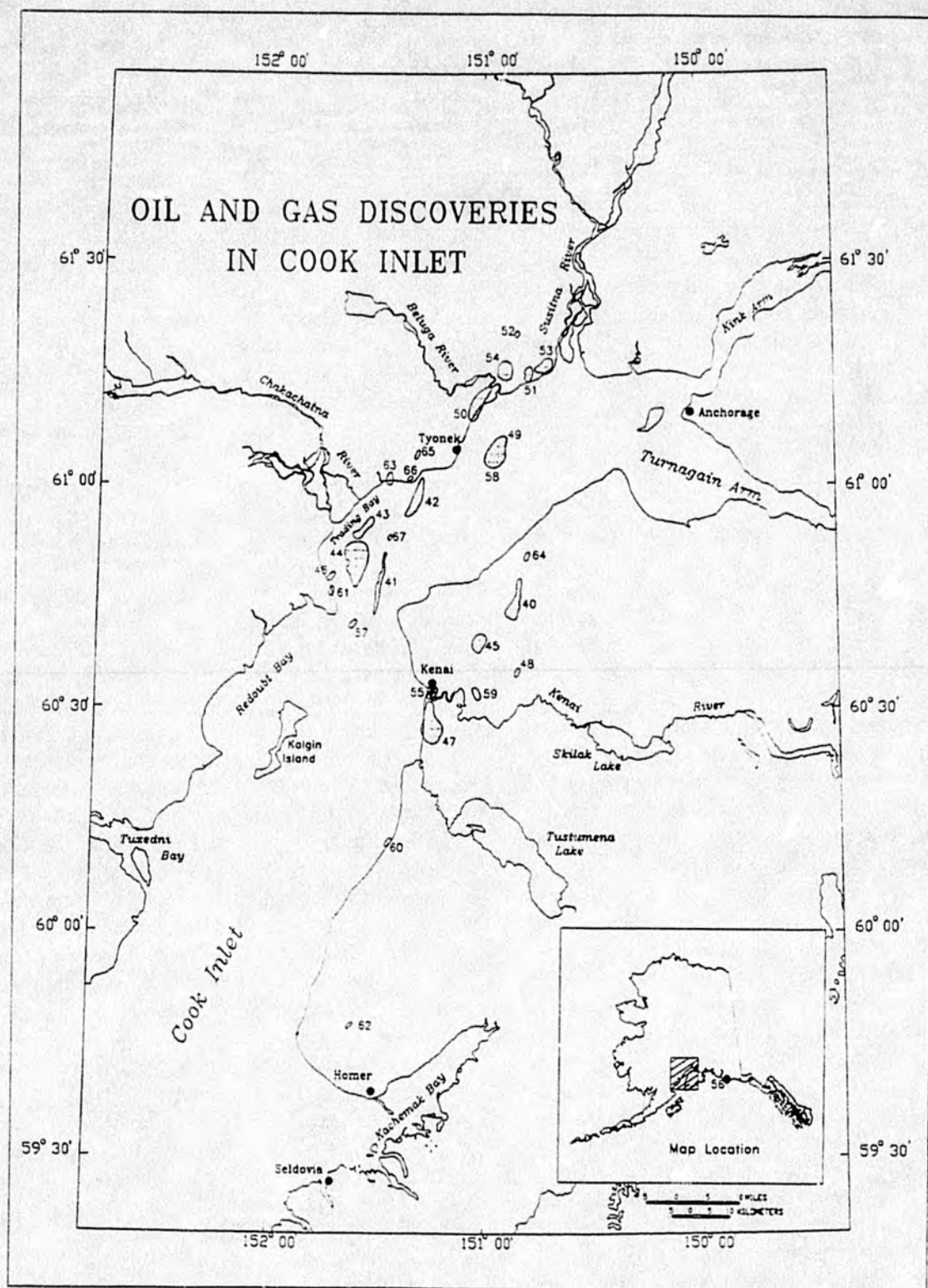


Figure 2. Oil and gas discoveries in Cook Inlet. (The numbers by the discoveries are keyed to table 9.)

in addition to providing a stable and predictable schedule as a basis for comprehensive reviews of potential benefits and impacts, enables the oil industry to target specific areas for exploration *before* the actual lease sale. Exploration for oil and gas prior to a lease sale follows a very logical and predictable path that begins with the gathering and compilation of existing technical information in the oil-company offices, the construction of geologic and geophysical maps and other displays to illuminate prospective areas, and the acquisition of additional information that may be desirable.

The first stage of "exploration" can be considered to be those activities and techniques that examine different aspects of the geologic model for hydrocarbon formation *before* leasing. For example, one group of geoscientists will review existing seismic data and previously drilled wells in a particular area to create subsurface maps that will be the basis for evaluating the area for potential subsurface traps. Another group may be in the field conducting studies of rock outcroppings, which may reveal information on source-rock potential, type of hydrocarbons, or the likelihood for reservoir rock in the subsurface. Engineers and economists may be looking at flow rates, potential productivity, or the drilling costs associated with known accumulations that have similarities to the area under investigation. When these studies reveal gaps in the data or interesting leads, additional seismic data may be acquired by individual companies, groups, or consortiums of companies, or by seismic-acquisition companies to sell later on speculation. Prospect maps generated at this stage are used to make probabilistic estimates of the amount of trapped petroleum. The same maps are used to guide the companies' competitive bids at the time of the lease sale. The most potentially "intrusive" activity during this first phase of exploration is the acquisition of new seismic data if the companies deem it necessary.

The second stage of exploration occurs after lease acquisition, following a lease sale. At this point a company knows which lands it has rights to and can begin a thorough evaluation of that land. Again, the predominant activity in this phase is unobtrusive studies conducted primarily in the office. For example, if a block of leases has been acquired and there is a greater expectation of an eventual return on investment, expenditures toward the evaluation effort can be increased. At this point, advanced computer mapping techniques are used to analyze and refine geologic interpretations and produce upgraded, more detailed subsurface prospect maps. Much time and effort is put into these types of complex analyses. At the same time, company officers may contact other companies that also acquired a lease interest in the area and may be interested in joint exploration to trim costs, increase efficiency, and spread risk. If the mapped prospects look

good both geologically and economically when stacked up against dozens, or perhaps hundreds, of other prospects or investment opportunities, and if the companies' financial situations are favorable given the current timing and management philosophy, further exploration expenditures may be considered.

At times, the second stage of exploration will lead to another round of seismic-data acquisition and subsequent interpretation. Today, with advanced computer modeling and three-dimensional seismic surveys, it is often more cost effective to acquire new and better seismic data, re-interpret the prospect by integrating the new data, and conduct another round of even more rigorous prospect delineation than it is to go out at this point and drill an exploration well. Despite all the expensive technology, however, no amount of studies provide any certainty that hydrocarbons are present, and there are no methods to directly detect commercial hydrocarbons beneath the surface. Only drilling can determine the actual presence of producible hydrocarbons.

The third stage of exploration entails the actual drilling of an exploration well. At this point, the prospect beneath a lease has survived an exhaustive geologic and economic "culling" and review process, and all the other needed elements such as timing, rig availability and suitability, intercompany coordination, allocation of exploration budgets, and management commitment have finally come together. The results of the first exploration well, which may take months to fully analyze, will determine the next course of action. In most cases—as the statistics in this report show—an exploration well fails to find a hydrocarbon deposit. However, if the results are positive and hydrocarbon-bearing rocks are encountered, additional delineation drilling and seismic data acquisition may be needed. Further lease acquisition or intercompany agreements may also be desirable. The decision to pursue further delineation drilling is based primarily on the perceived (or potential) commerciality of the deposit. The estimated size and the complexity of a newly discovered deposit will generally govern the number of delineation wells needed (and the timing of the drilling of these tests) in this latter stage of exploration.

All the data from the exploration and delineation wells and from the geological and geophysical mapping efforts are used to rigorously refine the assessment of in-place and recoverable hydrocarbons trapped in the prospect. This complex interpretation of the quantity and producibility of the deposit is considered in light of engineering and economic models that assess the feasibility, costs, and timing of development. Within a time period of 5 to 10 years from lease acquisition through discovery and delineation, a go or no-go decision on development is finally made. At this stage—when a new discovery has been sufficiently delineated and the

companies make a commitment to commercial development by applying to form development units, participating areas, or pool rule areas—the exploration phase can be considered complete.

DATABASE AND SOURCES OF INFORMATION

The data used in this analysis and the various compilations and calculations are displayed in tables 1-12 and figures 3 and 4. Locations of the oil and gas discoveries are depicted on the maps of northern Alaska and Cook Inlet in figures 1 and 2. The historical information on competitive lease sales was compiled from data supplied by the Alaska Department of Natural Resources, Division of Oil and Gas. Much of the lease-sale data can be found in the division's 1993 Five-Year Oil and Gas Leasing Program document. Updates through the current year and further details of mixed sale areas were provided by division staff.

Federal lease sales data were obtained from the 1994 Alaska OCS Statistical Summary by the Alaska Regional Office of the Minerals Management Service and compiled from their master list of leases. The Bureau of Land Management provided data for the onshore competitive sales held in National Petroleum Reserve-Alaska (NPR).

Information on known oil and gas fields, discoveries, and undeveloped accumulations was compiled from the 1994 Division of Oil and Gas Historical and Projected Oil and Gas Consumption report. Updated material and more recent information on estimated volumes were provided by division staff.

Finally, the Petroleum Information Corporation well database on CD-ROM (PetroROM Well Data), subscribed to by the Division of Oil and Gas and current through April 1994, provided a means to conduct searches by well type to assess the numbers of exploration wells drilled by region of the state.

RESULTS OF ANALYSIS

LEASING DATA

From December 10, 1959, to the present, 89 state and federal sales have been conducted in Alaska. Twelve other sales (six state and six federal) have been canceled for various reasons. The areas offered for lease encompass onshore and offshore lands that overlie parts of sedimentary basins throughout the state, along the coastline, and into the federal Outer Continental Shelf (OCS). The two dominant areas of leasing, exploration, and development are Cook Inlet and northern Alaska (tables 1-3, figs. 1 and 2).

Table 10 provides details of the compiled lease sales data. The 89 state and federal lease sales, combined, have offered 34,096 tracts for competitive leasing, or a combined total of 171,069,120 acres. The state alone, in 68 sales, has offered 9,018 tracts (26,686,902 acres), and leased 4,654 tracts (11,611,495 acres). The federal government, in 21 sales, has offered 25,078 tracts (144,382,218 acres), and leased 1,618 tracts (9,894,273 acres). Of the state tracts leased, only 1,148 remain active (validly held and rentals being paid) as of May 1994. The federal government reports 334 active OCS leases and about 155 active onshore leases (an accurate account of the onshore leases was not available from the Bureau of Land Management) as of February 1994, and the number of leases being "relinquished" (returned) is increasing.

In this compilation, some of the tracts *offered* include some reoffered tracts or acreage that represent either multiple offerings of the same lands that were not leased initially or lands leased once and then reoffered. In addition, the tracts and acreage *leased* also include some lands that may have been leased more than once. With the current database it is difficult to separate first-time, original tract offerings from multiple offerings. However, inasmuch as each lease sale is a distinct event in time, at which tracts may (or may not) receive bids, distinguishing between these categories is not thought to be significant.

For comparison, a 1994 Land Status (Ownership) Map (oral commun., Mark Myers, Department of Natural Resources) with sedimentary basin outlines was used to estimate that the total state acreage available for leasing in Cook Inlet is about 8 million acres and in northern Alaska, about 14 million acres. This combined estimate (about 22 million acres) compares favorably to the total state Cook Inlet (10,412,283 acres) and northern Alaska (13,416,981 acres) acreage already offered for lease (23,829,264 acres). Because the state has offered virtually all its Cook Inlet and northern Alaska lands for lease, the inference is that perhaps as much as 2 million acres—mostly in Cook Inlet—would fall in one of the categories of reoffered lands.

The statistics in table 10 show that the total number of state tracts leased in all 68 state sales represents an average of about 51.6 percent of the tracts offered. This number is somewhat smaller (43.5 percent) when calculated based upon acreages offered and leased. The average number of federal tracts leased in the 21 federal offerings is only about 6.4 percent, or when calculated based on acreage, about 6.8 percent. The discrepancy in these percentages is undoubtedly a result of the large OCS areas the Minerals Management Service has historically offered for leasing. Federal lease sales in areas such as the Navarin Basin, Chukchi Sea, Beaufort Shelf, and even in NPR, encompass millions of acres in a single offering, compared to state sales which historically offer only hundreds

of thousands of acres. In addition, it is likely that the high costs associated with exploration programs in the arctic and western Alaska OCS have had a dampening effect on leasing in those areas. For these reasons, the combined average of all (federal and state) tracts leased of about 18.4 percent is viewed as probably not being a very meaningful historical estimate. Rather, more importance should be placed on the individual state and federal averages.

Another calculation was performed on just the state sales in the two dominant oil and gas regions of the state, Cook Inlet and northern Alaska. In 34 Cook Inlet offerings (comprised of 27 sales and the Cook Inlet portion of seven other sales), about 56.4 percent of the tracts were leased (48.1 percent based upon acreage). In 31 northern Alaska sales (comprised of 29 sales and portions of two other sales), about 49.7 percent of the tracts were leased (43.5 percent based upon acreage).

KNOWN DEPOSITS AND DRILLED WELLS

All known hydrocarbon deposits in the state are listed on tables 4-9, 11. There are currently 28 developed fields (12 in northern Alaska, 16 in Cook Inlet) producing oil or gas or both; as of May 1994, the total number of state leases contributing to this production is 282. No federal OCS leases currently produce, but 35 onshore leases in Cook Inlet do have production.

Table 11, provides a summary of Alaska hydrocarbon deposits. The total number of undeveloped accumulations or discoveries in northern Alaska is 27, which includes Point Thomson and Flaxman Island as two separate discoveries. In Cook Inlet, there are 11 additional known, but currently nonproducing, accumulations. These include three fields that have previously produced but are now shut in (Sterling, Nicolai Creek, and Moquawkie). Table 11 also includes the abandoned Katalla field onshore in the Gulf of Alaska. The total number of known, but nonproducing, accumulations for the state is 39.

The grand total of all Alaska discoveries—the combined number of producing fields and nonproducing accumulations—is 67.

The well database used to assess numbers of exploration wells is organized into onshore and offshore parts on CD-ROM for Alaska. These categories are not strictly adhered to in all cases, as the "onshore" listing contains many wells drilled offshore in state waters along the northern Alaska Beaufort Sea coast and in Cook Inlet. These and other minor problems with the data format do not materially impact the validity of the data sorts performed in this analysis. This database employs 11 categories to describe initial well status, ranging from new field wildcat to development wells, injection wells,

stratigraphic tests and others. For this analysis, exploration wells are considered to be those wells that fall into the following three status categories: new field wildcat, new pool wildcat, and outpost-extension.

The total number of wells (all types) drilled in Alaska through April 1994 is 4,057 according to the database (table 11). A convenient dividing line for separating the North Slope Basin (north of the Brooks Range) from the rest of the state is lat 68° N. The database reveals that north of this latitude, 2,911 wells have been drilled; south of this line, 1,146 wells have been drilled. A total of 751 exploration wells have been drilled in the state through April 1994. In northern Alaska, which includes all onshore areas north of lat 68° N., the Beaufort Sea, and the Chukchi Sea, 350 exploration wells have been drilled. In Cook Inlet, the area between lat 58.5°-62° and long 149°-153.5°, 266 exploration wells have been drilled.

CONCLUSIONS

Historical leasing data show that, on average, about half of the tracts offered in state sales are ultimately leased (51.6 percent of the tracts are leased or 43.5 percent of the acreage offered is leased). Average for state Cook Inlet leased tracts is slightly higher (56.4 percent) and the federal averages are considerably lower. The significance of this lease information is that although virtually all the offered tracts will have undergone an initial stage of exploration prior to the lease sale, only about half of the offered tracts have undergone the more rigorous second stage of exploration, which may involve a second phase of seismic-data acquisition.

In the third exploration stage (exploratory wells), the number of tracts initially offered for lease that might be drilled has already been reduced by about half. Information from the well database shows that 751 exploratory wells have been drilled in Alaska from 1900 through April 1994. This number includes 79 early wells (many in Katalla and NPRA) that were drilled prior to 1960. The state competitive leasing program began with the Cook Inlet Lease Sale 1 on December 10, 1959, and the federal program in Alaska began with Sale 39 in 1976. Thus, the total number of drilled exploratory wells resulting from competitive leasing is 672. It is reasonable to assume that most of these wells were located on separate tracts, that is, there were not two or more exploratory wells on a given lease. This information leads to the conclusion that of the total number of leased tracts in all state and federal competitive sales (6,272), only 672 were actually drilled (10.7 percent) (table 12). If this percentage is calculated just for state leases and exploratory wells (which is difficult because of the data format), the estimate is slightly higher.

Examining the data further reveals the success ratio (percent of discoveries versus the number of drilled exploration wells) of exploratory drilling in Alaska. For example, the total number of discoveries (producing fields plus all other known accumulations) for Alaska is 67. Eleven of these deposits (mostly in NPRA) were identified before competitive leasing began in December 1959 (table 9). The historical success ratio of exploratory drilling since 1960 is the 56 discoveries divided by the 672 exploratory wells, or about 8.3 percent (table 12). This calculation assumes that only one exploratory well was drilled on each discovery, an assumption that is not totally valid inasmuch as one or two delineation wells drilled after the initial discovery well may be counted in the "exploration well count." However, even if the well count is arbitrarily reduced to 600 exploratory wells, the success ratio only rises to about 9.3 percent, indicating that the originally calculated 8.3 percent success ratio is still within a reasonable and logical range.

Finally, it is important to examine the success ratios for *commercially successful* discoveries. In Alaska, there are currently 28 producing oil or gas accumulations, and three other fields (Sterling, Nicolai Creek, and Moquawkie) that have produced in the past. Three currently producing fields were found prior to 1960 (South Barrow, Swanson River, and Kenai gas fields). Therefore, 28 fields meet the criteria of current or past production since Sale 1. The 28 fields divided by the 672 exploratory wells reveal that about 4.2 percent of the exploratory wells drilled since 1960 have found commercially viable fields in Alaska (table 12). Again, this calculation assumes that only one exploratory well was drilled on each commercial field, an assumption that is not totally valid inasmuch as one or two delineation wells drilled after the initial discovery well may be counted in the "exploration well count." However, an arbitrary reduction in the exploratory well count does not significantly affect the range of the 4.2 percent estimated commercial success ratio.

As of May 1994, 282 state and 35 federal leases were producing hydrocarbons. Twelve additional leases (oral commun., Bill Van Dyke, Department of Natural Resources) have produced hydrocarbons at some point in the past (from fields or parts of fields that are now shut in), bringing the total number of state and federal leases that have produced or are currently producing to about 329. Therefore, of the total state and federal tracts leased (6,272) only about 5.2 percent ($329/6,272 \times 100$) are being (or have been) commercially produced (table 12). This

number is slightly higher (about 6.3 percent) when calculated with just the 4,654 state tracts leased and state producing leases (294). When calculated with the 9,018 total state tracts *offered* for lease (table 1), just 3.3 percent ($294/9,018 \times 100$) of the total state tracts offered for lease were or are being produced.

The state has realized enormous financial benefits from leasing its subsurface oil and gas rights. Revenues from bonuses, rentals, royalties, and taxes on petroleum exploration and development have contributed tremendously to the state's economy, infrastructure, standard of living, and fiscal health. Potential or perceived conflicts between the state's leasing program and other activities have historically been evaluated in the best-interest findings, which were compiled by the department prior to leasing.

Data compiled and analyzed in this study can help increase public understanding of the process and results of state and federal land leasing for oil exploration. The study points out that when land is made available for lease, only half will be leased; of the land leased, only a small percentage will be explored; and the exploration of a still smaller percentage of the leases will lead to discovery of oil and subsequent development.

KEY HISTORICAL PERCENTAGES

- About half of the state tracts offered for leasing have actually been leased.
- About 10.7 percent of the state and federal tracts leased have actually been drilled.
- Discoveries have been made by about 8.3 percent of all the state and federal exploratory wells drilled since competitive leasing began.
- Commercial deposits have been found by about 4.2 percent of all the state and federal exploratory wells drilled since competitive leasing began.
- About 5.2 percent of the total state and federal tracts leased have been commercially developed (were or are being produced). About 3.3 percent of the total state tracts offered for lease have been commercially developed (were or are being produced).

ACKNOWLEDGMENTS

I thank Gil Mull of the Alaska Division of Geological & Geophysical Surveys for his encouragement and thoughtful review of this paper.

Table 1. Summary of past state competitive lease sales as of May 1994

Sale	Sale date	Acres offered	Percent leased	Acres leased	Average \$/acre	Tracts offered	Tracts leased	Bonus received	Dominant area	Area
1	12/10/59	88,055.00	87.66%	77,191.00	52.08	37	31	\$ 4,020,342.43	Cook Inlet	Wide Bay, Kenai to Ninilchik, Kachemak Bay
2	7/13/60	17,567.51	93.96%	16,505.57	24.70	27	26	407,654.54	Cook Inlet	Kenai Pen., W. Forelands, Nushagak Bay
3 (1)*	12/7/60	73,047.70	31.30%	22,866.70	1.54	26	9	35,325.31	Mixed	Katalla, Kalifonsky Beach, Herendeen Bay
4	1/25/61	400	100.00%	400	679.04	3	3	271,614.40	Cook Inlet	Ninilchik uplands
5 (2)	5/23/61	97,876.00	98.06%	95,980.00	74.71	102	99	7,170,464.88	Mixed	Tyonek, Controller Bay, Pavlov Bay
6	8/4/61	13,257.00	100.00%	13,257.00	8.35	6	6	110,671.55	Gulf Ak.	Controller Bay
7 (3)	12/19/61	255,708.44	73.18%	187,118.44	79.43	68	53	14,863,049.33	Mixed	Icy, Yakutat, Kachemak bays, S. Kenai, N. CI
8	4/24/62	1,061.70	100.00%	1,061.70	4.80	8	8	5,097.00	Cook Inlet	Big Lake, uplands
9 (4)	7/11/62	315,668.93	83.77%	264,436.93	59.42	89	70	15,714,112.60	Mixed	Tyonek, Knik, Kalgin Is., S. Kenai, Wide Bay
10	5/8/63	167,583.06	84.43%	141,490.51	29.23	200	158	4,136,224.92	Cook Inlet	Tyonek, Kenai, offshore/uplands
11	8/2/63		CANCELED							Yakutat Bay
12	12/11/63	346,782.40	71.25%	247,089.00	12.31	308	207	3,042,680.74	Cook Inlet	Forelands, Knik/Turnagain, U. CI, Kenai Pen.
13 (5)	12/9/64	1,194,373.00	60.39%	721,224.00	7.68	610	341	5,537,099.85	Mixed	Fire Is., W. Forelands, Prudhoe West
14	7/14/65	754,033.00	53.45%	403,000.00	15.25	297	159	6,145,472.59	North Slope	Prudhoe west to Canning R., offshore/uplands
15	9/28/65	403,042.06	74.87%	301,751.28	15.49	293	216	4,674,343.74	Cook Inlet	N. CI, Kalgin, Redoubt Bay, Knik, S. Kenai
16 (6)	7/19/66	184,410.05	72.66%	133,987.29	52.55	205	153	7,040,880.17	Mixed	Kenai Pen., N. CI, Middleton Is., Redoubt Bay
17	11/22/66	19,229.70	96.67%	18,589.70	7.33	36	35	136,279.67	Cook Inlet	Big Lake, Kenai, offshore/uplands
18 (7)	1/24/67	47,729.00	91.47%	43,657.00	33.90	23	20	1,479,906.19	Mixed	Katalla, Prudhoe, offshore/uplands
19	3/28/67	2,560.00	REJECTED 12/9/74							Lower Cook Inlet, offshore/uplands
20	7/25/67	311,249.89	82.39%	256,447.31	73.14	295	220	18,757,340.88	Cook Inlet	Big Lake, Knik, N. CI, Kalgin Is., Ninilchik
21	3/26/68	346,623.00	47.59%	164,961.00	18.24	308	147	3,009,224.00	Ak. Pen.	Port Heiden and Port Moller, offshore
22	10/29/68	111,199.48	54.20%	60,272.15	17.29	230	125	1,042,219.90	Cook Inlet	Big Lake, W. Forelands, Kachemak. to Kenai
23	9/10/69	450,858.47	91.50%	412,548.47	2,181.66	179	164	900,041,605.34	North Slope	Colville to Canning R., offshore/uplands
24	5/12/71	196,635.07	47.10%	92,617.97	4.92	244	106	455,640.57	Cook Inlet	Big Lake, Knik, Kenai, West Forelands
25	9/26/72	325,401.42	54.78%	178,244.71	7.43	259	152	1,324,673.40	Cook Inlet	Big Lake, Knik, Belukha, N. CI
26	12/11/72	399,920.96	44.50%	177,972.56	8.75	218	105	1,557,848.84	Cook Inlet	North Cook Inlet
27	5/9/73	308,400.81	36.93%	113,891.71	9.92	210	96	1,130,324.51	Cook Inlet	Tuxedni, Ninilchik, Kenai, Kalgin
28	12/13/73	166,648.04	58.69%	97,803.69	253.77	98	62	24,819,189.91	Cook Inlet	Ninilchik, Kachemak Bay, Belukha
29	10/23/74	278,269.43	45.68%	127,119.65	8.19	164	82	1,040,909.98	Cook Inlet	Kalgin, Ninilchik, N. CI, Turnagain, Big Lake
29A	10/17/78		CANCELED							Point Thomson
29B	7/24/79	34,678.04	100.00%	34,678.04	4.56	20	20	158,041.78	Copper R.	Copper River Basin
30	12/12/79	341,140.18	86.86%	296,307.65	1,914.87	71	62	567,391,497.48	North Slope	Beaufort Sea (Joint Federal & State)
31	9/16/80	196,268.00	100.00%	196,268.00	63.12	78	78	12,387,469.60	North Slope	Prudhoe uplands, Kuparuk R. to Mik. Bay
33	5/13/81	815,000.00	52.76%	429,978.16	10.00	202	103	4,299,781.60	Cook Inlet	Upper CI, Kenai Pen., Susitna
32	8/25/81	202,836.74	75.15%	152,428.22	10.00	78	59	1,524,282.20	Cook Inlet	Lower Cook Inlet, Kenai Pen. and offshore
35	2/2/82	601,171.50	21.82%	131,190.69	10.00	149	31	1,311,906.90	Cook Inlet	Lower CI, Kenai Pen., Redoubt north to Drift R.
36	5/26/82	56,862.41	100.00%	56,862.41	573.02	13	13	32,583,451.87	North Slope	Beaufort Sea, Pt. Thomson area
37	8/24/82	852,603.08	19.80%	168,849.00	3.33	217	33	562,943.90	Copper R.	Middle Tanana and Copper River basins
37A	8/24/82	1,874.60	100.00%	1,874.60	52.00	1	1	97,479.20	Cook Inlet	Chakok River Exempt (Kenai Pen.)
34	9/28/82	1,231,517.00	46.44%	571,954.00	46.70	261	119	26,713,018.17	North Slope	Prudhoe uplands, Sag R. to Canning R.

Table 1. Summary of past state competitive lease sales as of May 1994 (cont.)

Sale	Sale date	Acres offered	Percent leased	Acres leased	Average \$/acre	Tracts offered	Tracts leased	Bonus received	Dominant area	Area
38	1/19/83		CANCELED							Norton Basin
39	5/17/83	211,988.08	100.00%	211,988.08	99.05	42	42	\$20,998,100.98	North Slope	Beaufort Sea, Gwydyr Bay to Harrison Bay
40	9/28/83	1,044,745.02	42.44%	443,354.88	7.17	284	140	3,177,178.26	Cook Inlet	Upper CI, Anchorage south to Homer
42	1/24/84		CANCELED							Minchumina Basin
43&43A	5/22/84	374,152.89	95.65%	357,863.02	94.53	84	81	33,827,377.15	North Slope	Beaufort, Pitt Pt. to Harrison Bay; Colville/PB
41	9/18/84	1,437,930.46	19.40%	278,938.96	3.03	308	63	843,964.92	Bristol Bay	Bristol Bay Uplands: Kvichak R. to Port Heiden
46A	2/26/85	248,584.64	76.45%	190,041.54	13.28	65	50	2,523,333.71	Cook Inlet	CI Exempt, Kenai Pen., Susitna, N. CI
45A	9/24/85	606,385.00	27.19%	164,885.00	28.25	113	32	4,657,478.08	North Slope	NS Exempt, Canning R. to Colville R.
47	9/24/85	192,568.81	94.80%	182,559.81	63.79	50	48	11,645,003.26	North Slope	Kuparuk Uplands; south of Prudhoe Bay
48	2/25/86	526,101.00	50.70%	266,736.00	9.16	104	54	2,444,341.85	North Slope	Kuparuk Uplands: south of Kuparuk oil field
48A	2/25/86	42,053.00	100.00%	42,053.00	12.13	11	11	510,255.16	North Slope	Mikkelsen Bay, Foggy Is. Bay
49	6/24/86	1,189,099.61	33.21%	394,880.74	2.40	260	98	947,171.27	Cook Inlet	Kalgin Is., Yentna/Skwentna, Alexander Cr.
51	1/27/87	592,142.00	16.99%	100,632.00	2.88	119	26	289,624.90	North Slope	Prud. Bay Uplands, Canning R. to Sag R.
50	6/30/87	118,147.31	100.00%	118,147.31	56.05	35	35	6,621,722.81	North Slope	Camden Bay, Flaxman Is. to Hulahula R.
54	1/26/88	421,809.16	80.29%	338,687.16	13.83	89	72	4,683,388.24	North Slope	Kuparuk Uplands, Colville R. delta
66A	6/28/88		CANCELED							North Slope Exempt
55	9/28/88	201,706.79	47.91%	96,631.90	152.13	56	25	14,700,602.00	North Slope	Demarcation Pt., Canning R. to Canada
69A	9/28/88	775,555.00	47.51%	368,490.00	16.61	155	75	6,119,135.00	North Slope	Kuparuk Uplands, Canning R. to Colville R.
52	1/24/89	175,981.48	29.81%	52,463.34	33.12	43	15	1,737,512.66	North Slope	Beaufort Sea, Pitt Point to Tangent Point
72A	1/24/89	677.15	100.00%	677.15	671.90	1	1	454,977.40	North Slope	Oliktok Point uplands
67A	1/29/91	549,364.06	34.87%	191,588.06	28.77	140	55	5,511,338.27	Cook Inlet	CI Exempt, Anch., Upper CI, Kenai Pen.
70A	1/29/91	532,152.82	79.03%	420,567.82	65.88	135	109	27,707,540.94	North Slope	Kuparuk Uplands, Canning R. to Colville R.
64	6/4/91	754,542.40	4.52%	34,143.00	7.10	141	6	242,389.00	North Slope	Kavik, Canning R. to Sagavanirktok R.
65	6/4/91	491,090.94	35.20%	172,864.61	40.46	108	36	6,993,949.12	North Slope	Beaufort Sea, Pitt Point to Canning R.
74	9/24/91	605,850.89	4.39%	26,604.99	12.06	134	5	320,852.72	Cook Inlet	Nikishka to Ninilchik, Drift R., N. CI
61	1/22/92	991,087.00	26.29%	260,550.00	9.32	181	46	2,429,551.00	North Slope	White Hills, Colville R. to White Hills
68	6/2/92	153,445.00	0.00%	0	0.00	36	0	0	North Slope	Beaufort Sea, Nulavik to Tangent Point
75	12/8/92	217,205.00	57.47%	124,832.00	78.11	90	55	9,750,111.21	North Slope	Kuparuk Uplands, Colville to Sag R.
76	1/26/93	393,024.70	36.00%	141,503.66	461.25	86	36	65,269,166.65	Cook Inlet	Upper Cook Inlet
67 A-W	1/26/93	282,577.26	45.94%	129,809.69	18.75	69	33	2,433,863.85	Cook Inlet	West Cook Inlet
77	5/25/93	1,260,146.00	3.63%	45,727.00	25.47	228	8	1,164,555.34	North Slope	Nanushuk onshore, Chandler to Ivishak.. R.
70 A-W	5/25/93	37,655.00	74.51%	28,055.00	48.41	11	8	1,358,027.12	North Slope	Kuparuk Uplands, Canning to Kavik R.
57	9/21/93	1,033,248.01	0.00%	0	0.00	196	0	0	North Slope	North Slope Foothills
75A	9/21/93	14,342.72	100.00%	14,342.72	31.36	11	11	449,846.80	North Slope	Colville River Exempt
TOTALS:		26,686,901.87	43.51%	11,611,494.55	164.91	9,018	4,654	\$1,914,812,429.61		

* (1-7 refers to mixed areas described in table 2.)

Table 2. Details of mixed state lease-sale areas

Mixed areas	Sale number	Sale date	Acres offered	Percent leased	Acres leased	Average \$/acre	Tracts offered	Tracts leased	Bonus received	Dominant area	Area
(1)	3 CI	12/7/60	1,851.70	100.00	1,851.70	5.41	1	1	\$ 10,026.25	Cook Inlet	Kalifonsky Beach area
	3 GOA	12/7/60	12,275.00	42.83	5,257.00	1.10	6	3	5,777.81	Gulf Ak.	Katalla area
	3 Kod	12/7/60	12,270.00	0.00	0.00	0.00	4	0	0.00	Kodiak	Offshore Kodiak
	3 Ak. Pen.	12/7/60	46,651.00	33.78	15,758.00	1.24	15	5	19,521.25	Ak. Pen.	Herendeen Bay
		Totals:	73,047.70	31.30	22,866.70	1.54	26	9	35,325.31		
(2)	5 CI	5/23/61	58,275.00	96.75	56,379.00	124.84	93	90	7,038,533.38	Cook Inlet	Tyonek area
	5 GOA	5/23/61	23,508.00	100.00	23,508.00	2.82	6	6	66,203.88	Gulf Ak.	Controller Bay
	5 Ak. Pen.	5/23/61	16,093.00	100.00	16,093.00	4.08	3	3	65,727.62	Ak. Pen.	Pavlov Bay
		Totals:	97,876.00	98.06	95,980.00	74.71	102	99	7,170,464.88		
(3)	7 CI	12/19/61	205,251.44	72.06	147,911.44	98.66	56	44	14,593,659.13	Cook Inlet	S. Kenai, N. CI
	7 GOA	12/19/61	50,457.00	77.70	39,207.00	6.87	12	9	269,390.20	Gulf Ak.	Icy Bay, Yakutat
		Totals:	255,708.44	73.18	187,118.44	79.43	68	53	14,863,049.33		
(4)	9 CI	7/11/62	310,310.46	85.00	263,758.46	59.24	84	74	15,626,116.56	Cook Inlet	Tyonek, Knik, S. Kenai
	9 Ak. Pen.	7/11/62	5,358.47	12.66	678.47	129.70	5	2	87,996.04	Ak. Pen.	Wide Bay
		Totals:	315,668.93	83.77	264,436.93	59.42	89	76	15,714,112.60		
(5)	13 CI	12/9/64	569,916.00	44.97	256,299.00	4.53	361	157	1,160,576.56	Cook Inlet	Fire Is., W. Forelands areas
	13 N. Ak.	12/9/64	624,457.00	74.45	464,925.00	9.41	249	184	4,376,523.29	N. Alaska	Prudhoe West area
		Totals:	1,194,373.00	60.39	721,224.00	7.68	610	341	5,537,099.85		
(6)	16 CI	7/19/66	153,441.05	69.63	106,835.29	24.18	181	132	2,583,748.87	Cook Inlet	Kenai Pen., N. CI
	16 GOA	7/19/66	30,969.00	87.67	27,152.00	164.15	24	21	4,457,131.30	Gulf Ak.	Middleton Island
		Totals:	184,410.05	72.66	133,987.29	52.55	205	153	7,040,880.17		
(7)	18 N. Ak.	1/24/67	37,662.00	100.00	37,662.00	39.02	15	15	1,469,645.39	N. Alaska	Prudhoe area
	18 GOA	1/24/67	10,067.00	59.55	5,995.00	1.71	8	5	10,260.80	Gulf Ak.	Katalla
		Totals:	47,729.00	91.47	43,657.00	33.90	23	20	1,479,906.19		

Table 3. Summary of past federal lease sales (updated February 1994)

Sale	Sale date	Acres offered	Percent leased	Acres leased	Average \$/acre	Blocks offered	Blocks leased	High bid total ^a	Bonus received	Area
39	4/13/76	1,008,499.00	40.56	409,058	1,368.60	189	76	\$571,871,587	\$559,836,587	Gulf of Alaska
CI	10/27/77	768,580.00	64.44	495,307	804.49	135	87	400,319,543	398,471,313	Cook Inlet
BF	12/11/79	173,423.00	49.46	85,776	5,697.29	46	24	491,728,138	488,691,138	Beaufort Sea
55	10/21/80	1,195,569.00	16.67	199,261	550.79	210	35	117,550,113	109,751,073	Gulf of Alaska
RS-1	6/30/81	996,300.00	0.57	5,693	29.95	175	1	3,091,738	170,496	Gulf of Alaska
60	9/29/81	858,247.00	8.52	73,157	60.23	153	13	4,405,899	4,405,899	Cook Inlet
821	1/27/82	1,516,257.00	44.57	675,816	86.34	59	26	na	58,351,262	NPRA
822	5/26/82	3,519,515.00	7.85	276,396	35.24	212	12	na	9,741,022	NPRA
RS-2	8/5/82	785,089.60	0.00	0	0.00	140	0	0	0	Cook Inlet
71	10/13/82	1,825,770.40	36.31	662,860	3,101.16	338	121	2,067,604,786	2,055,632,336	Beaufort Sea - Diapir Field
57	3/15/83	2,379,751.00	14.11	335,898	946.34	418	59	325,267,372	317,873,372	Norton Basin
70	4/12/83	2,688,787.00	20.12	540,917	788.40	479	96	427,343,830	426,458,830	St. George Basin
831	7/20/83	2,195,845.00	18.96	416,433	40.02	84	18	na	16,666,659	NPRA
85	3/9/84	CANCELED								Barrow Arch/Chukchi
83	4/17/84	28,048,995.00	3.31	927,989	556.38	5,036	163	631,228,331 ^b	516,317,331	Navarin Basin
841	7/18/84	1,590,677.00	0.00	0	0.00	64	0	na	0	NPRA
87	8/22/84	7,773,446.82	15.54	1,207,714	722.00	1,419	227	877,131,327 ^b	871,964,327	Beaufort Sea - Diapir Field
99	2/20/85	CANCELED								Shumagin
86	2/26/86	CANCELED								Shumagin
100	4/11/86	CANCELED								Norton Basin
89	5/2/86	CANCELED								St. George Basin
88	5/2/86	CANCELED	1							Gulf of Alaska
97	3/16/88	18,277,806.00	6.08	1,110,742	103.77	3,344	202	115,261,636 ^b	115,261,636	Beaufort Sea
109	5/25/88	25,631,122.00	7.47	1,914,285	249.72	4,694	350	478,177,948	478,032,631	Chukchi Sea
92	10/11/88	5,603,586.00	2.17	121,754	783.87	990	23	95,439,500	95,439,500	N. Aleutian Basin
124	6/26/91	18,556,976.24	1.49	276,004	60.89	3,417	57	16,807,025	16,807,025	Beaufort Sea
126	8/28/91	18,987,975.69	0.84	159,213	44.70	3,476	28	7,117,304	7,117,304	Chukchi Sea
TOTALS:		144,382,217.75	6.85	9,894,273	661.69	25,078	1,618	6,630,346,077	6,546,989,741	

^aIncludes only accepted and rejected high bid amounts.^bDoes not include 17 blocks (39,168 hectares) in Sale 83 affected by a Soviet claim of jurisdiction. Bids on these blocks were rejected on December 14, 1988. Does not include 4 blocks (9,216 hectares) in Sale 87 and 16 blocks (35,353 hectares) in Sale 97 affected by a Canadian claim of jurisdiction. Bids on these blocks have been determined to be adequate but will not be accepted or rejected until the U.S. determines that it is in its best interest to do so. The 1/5-bonus amounts received for these bids have been placed in an interest-bearing account.

Table 4. *Producing fields of northern Alaska as of January 1994*

Status	Years in production	No.	Field name	Year of discovery	Projected avg. 1994 daily prod. (x1000 bbls/day)	Estimated original recov. reserves	Cumulative production thru 1993	Remaining reserves as of 1/94	Est. ultimate recovery as of 1/94	Est. percent depleted as of 1/94
Oil production (Millions of barrels)										
P	1969-present	1	Prudhoe Bay	1967	1,078	9,590	8,307	3,618	11,925	69.7%
P	1981-present	2	Lisburne	1967	24	400	98	83	181	54.2%
P	1981-present	3	Kuparuk River	1969	315	1,200	1,070	1,142	2,212	48.4%
P	1985-present ^a	4	Milne Point ^b	1969	20	60	34	81	115	29.5%
P	1993-present	5	Prudhoe Bay other ^c	1970, 1976	6	25	1	25	26	3.2%
P	1986-present	6	Endicott ^d	1978	100	375	243	262	505	48.1%
P 4/9-1	1994	7	Niagakuk ^e	1985	10	55	0	55	55	0.0%
P	1993-present	8	Point McIntyre	1988	90	300	2	356	358	0.5%
TOTALS:						12,005	9,755	5,622	15,377	
Gas production (Billions of cubic feet)										
P	1958-present	1	South Barrow	1949	not available	25	21	4	25	84.0%
P	1969-present	2	Prudhoe Bay	1967	not available	28,500	1,631	21,551	23,182	7.0%
P	1981-present	3	Lisburne	1967	not available	635	70	277	347	20.2%
P	1981-present	4	Kuparuk River	1969	not available	640	261	709	970	26.9%
P	1985-present ^a	5	Milne Point ^{b,f}	1969	not available	n/a	9	n/a	n/a	n/a
P	1981-present	6	East Barrow	1974	not available	12	7	6	13	53.8%
P	1993-present	7	Prudhoe Bay other ^c	1976	not available	n/a	1	n/a	n/a	n/a
P	1986-present	8	Endicott ^d	1978	not available	731	71	908	979	7.3%
P	1992-present	9	Walakpa	1980	not available	n/a	1	n/a	n/a	n/a
TOTALS:						30,543	2,072	23,455	25,516	

P = producing

^aMilne Point was shut in for 1988 and part of 1987^bMilne Point includes Schrader Bluff; Schrader Bluff production commenced in 1991^cIncludes West Beach and N. Prudhoe Bay State (discovered in 1970) together^dIncludes Sag Delta North; Sag Delta production commenced in 1989^eIncludes Alapah (Lisburne)^fMilne Pt. is assigned no gas reserves because most of its gas will be used for production fuel

Sources: "Historical and Projected Oil and Gas Consumption," DNR, Feb. 1994; "Estimates of Oil Reserves in Alaska" and "Estimates of Gas Reserves in Alaska," AOGCC, Jan. 1994

Table 5. Significant undeveloped northern Alaska hydrocarbon accumulations as of January 1994

Status	Years in production	No.	Field name	Year of discovery	Projected avg. 1994 daily prod. (x1000 bbls/day)	Estimated original recov. reserves	Cumulative production thru 1993	Remaining reserves as of 1/94	Est. ultimate recovery as of 1/94	Est. percent depleted as of 1/94
Oil accumulations (Millions of barrels)										
UD	1983-1986 ^a	1	West Sak	1969	0	147	0.755	149	150	0.5%
UD	none	2	Point Thomson/Flaxman	1977 ^b	0	200	0	200	200	0.0%
UD	none	3	Northstar/Seal Island	1984	0	180	0	180	180	0.0%
Gas accumulations (Billions of cubic feet)										
UD	none	1	Point Thomson/Flaxman	1977	0	3,500	0	3,000	3,000	0.0%

UD = undeveloped

^aWest Sak Pilot Project

^bFlaxman Island accumulation discovered in 1975

Sources: "Historical and Projected Oil and Gas Consumption," DNR, Feb. 1994; "Estimates of Oil Reserves in Alaska" and "Estimates of Gas Reserves in Alaska," AOGCC, Jan. 1994

Table 6. *Other undeveloped northern Alaska hydrocarbon discoveries as of January 1994*

No.	Field name	Year of discovery	Estimated original recov. reserves
Oil discoveries (Millions of barrels)			
1	Umiat	1946	50
2	Fish Creek	1949	n/a
3	Simpson	1950	12
4	Mikkelson	1978	n/a
5	Gwydyr Bay	1981	n/a
6	Tern Island	1983	n/a
7	Hemi Springs	1984	n/a
8	Colville Delta	1985	n/a
9	Hammerhead	1986	n/a
10	Sandpiper Island	1986	n/a
11	Badami	1990	n/a
12	Kuvlum	1992	n/a
13	Fiord (Colville Delta)	1992	n/a
14	Kalubik (Colville Delta)	1992	n/a
15	Cascade	1993	n/a
16	Sourdough	1994	n/a

No.	Field name	Year of discovery	Estimated original recov. reserves
Gas discoveries (Billions of cubic feet)			
1	Meade	1950	20
2	Wolf Creek	1951	n/a
3	Gubik	1951	600
4	Square Lake	1952	58
5	East Umiat	1963	n/a
6	Kavik	1969	n/a
7	Kemik	1972	n/a

Table 7. Producing fields of Cook Inlet as of January 1994

Status	Years in production	No.	Field name	Year of discovery	Projected avg. 1994 daily prod. (x1000 bbls/day)	Estimated original recov. reserves	Cumulative production thru 1993	Remaining reserves as of 1/94	Est. ultimate recovery as of 1/94	Est. percent depleted as of 1/94
Oil production (Millions of barrels)										
P	1958-present	1	Swanson River (federal)	1957	n/a	217	219	11	230	95.2%
P	1968-present	2	Middle Ground Shoal	1962	6.1	162	169	16	185	91.3%
P	1967-present	3	Granite Point	1965	6.2	126	120	14	134	89.6%
P	1967-present	4	Trading Bay	1965	2.2	90	95	6	101	94.0%
P	1965-present	5	McArthur River	1965	17.9	574	561	42	603	93.0%
P	1972-present	6	Beaver Creek (federal)	1965	n/a	4	5	1	6	82.2%
P	1993-present	7	West McArthur River	1991	2	n/a	0	5	5	2.0%
TOTALS:						1,173	1,168	95	1,263	
Gas production (Billions of cubic feet)										
P	1958-present	1	Swanson River (federal)	1957	not available	259.000	0.000	165.000	165.000	0.0%
P	1960-present	2	Kenai	1959	not available	2,496.000	2,081.189	204.000	2,285.189	91.1%
P	1978-present*	3	West Fork	1960	not available	n/a	4.049	4.000	8.049	50.3%
P	1965-present	4	Middle Ground Shoal	1962	not available	86.000	91.983	11.000	102.983	89.3%
P	1969-present	5	North Cook Inlet	1962	not available	1,594.000	1,089.657	410.000	1,499.657	72.7%
P	1963-present*	6	Beluga River	1962	not available	1,003.000	455.358	375.000	830.358	54.8%
P	1967-present	7	Granite Point	1965	not available	105.000	104.804	33.000	137.804	76.1%
P	1965-present	8	Trading Bay	1965	not available	63.000	69.564	29.000	98.564	70.6%
P	1967-present	9	McArthur River	1965	not available	965.000	617.615	349.000	966.615	63.9%
P	1973-present	10	Beaver Creek (federal)	1965	not available	241.500	127.176	115.000	242.176	52.5%
P	1990-present	11	Ivan River	1966	not available	n/a	11.112	n/a	n/a	n/a
P	1984-present	12	Lewis River	1975	not available	n/a	8.157	n/a	n/a	n/a
P	1990-present	13	Stump Lake	1978	not available	n/a	4.464	185 ^c	194.302 ^c	2.1% ^c
P	1986-present	14	Pretty Creek	1979	not available	n/a	4.838	^c	^c	^c
P	1988-present	15	Cannery Loop	1979	not available	300.000	65.726	226.000	291.726	22.5%
P	1993-present	16	West McArthur River	1991	not available	n/a	0.031	n/a	n/a	n/a
TOTALS:						7,112.500	4,735.723	1,921.000	6,628.121	

P = producing

*West Fork was shut in from 1986 through 1990

*Beluga did not produce in 1965 and 1966

*Pretty Creek and Stump Lake remaining reserves and ultimate recovery are combined

Sources: "Historical and Projected Oil and Gas Consumption," DNR, Feb. 1994; "Estimates of Oil Reserves in Alaska" and "Estimates of Gas Reserves in Alaska," AOGCC, Jan. 1994

Table 8. Other known Cook Inlet^a hydrocarbon accumulations as of January 1994

Status	Years in production	No.	Field name	Year of Discovery	Projected avg. 1994 daily prod. (x 1000 bbls/day)	Estimated original recov. reserves	Cumulative production thru 1993	Remaining reserves as of 1/94	Est. ultimate recovery as of 1/94	Est. percent depleted as of 1/94
Oil accumulations (Millions of barrels)										
ABND	1904-1933	1	Katalla (Gulf of Alaska)	1902	0	n/a	0.154	n/a	n/a	n/a
UD	none	2	Redoubt Shoal	1968	0	n/a	0.000	n/a	n/a	0.0%
UD	none	3	Sunfish	1991	0	n/a	0.000	77.000	77.000	0.0%
Gas accumulations (Billions of cubic feet)										
SI	1962-1986	1	Sterling ^b	1961	not available	25.100	2.088	23.000	25.088	8.3%
UD	none	2	Falls Creek	1961	not available	n/a	0.019	13.000	13.019	0.1%
UD	none	3	West Foreland	1962	not available	n/a	0.000	20.000	20.000	0.0%
UD	none	4	N. Middle Ground Shoal	1964	not available	n/a	n/a	n/a	n/a	n/a
SI	1967-1970	5	Moquawkie	1965	not available	n/a	0.985	n/a	n/a	n/a
UD	none	6	North Fork	1965	not available	n/a	0.105	12.000	12.105	0.9%
SI	1968-1977	7	Nicolai Creek	1966	not available	n/a	1.062	2.000	3.062	34.7%
UD	none	8	Birch Hill	1967	not available	11.000	0.065	11.000	11.065	0.6%
UD	none	9	Albert Kaloa	1968	not available	n/a	0.119	n/a	n/a	n/a

^aIncludes Katalla, onshore in the Gulf of Alaska^bSterling field has been shut in since 1987

ABND = abandoned

UD = undeveloped

SI = shut-in

Sources: "Historical and Projected Oil and Gas Consumption," DNR, Feb. 1994; "Estimates of Oil Reserves in Alaska" and "Estimates of Gas Reserves in Alaska," AOGCC, Jan. 1994

Table 9. Complete listing of all Alaska discoveries

No.	Field/accumulation	Discovery date	Fluid type(s)	Status	No.	Field/accumulation	Discovery date	Fluid type(s)	Status
Northern Alaska					Cook Inlet				
1	Prudhoe Bay	1967	Oil, Gas	P	40	Swanson River	1957	Oil, Gas	P
2	Lisburne	1967	Oil, Gas	P	41	Middle Ground Shoal	1962	Oil, Gas	P
3	Kuparuk River	1969	Oil, Gas	P	42	Granite Point	1965	Oil, Gas	P
4	Milne Point	1969	Oil, Gas	P	43	Trading Bay	1965	Oil, Gas	P
5	Prud. Bay - West Beach	1976	Oil, Gas	P	44	McArthur River	1965	Oil, Gas	P
6	Prud. Bay - N. PB St.	1970	Oil, Gas	P	45	Beaver Creek	1965	Oil, Gas	P
7	Endicott	1978	Oil, Gas	P	46	West McArthur River	1991	Oil, Gas	P
8	Niakuk	1985	Oil	P	47	Kenai	1959	Gas	P
9	Point McIntyre	1988	Oil, Gas	P	48	West Fork	1960	Gas	P
10	South Barrow	1949	Gas	P	49	North Cook Inlet	1962	Gas	P
11	East Barrow	1974	Gas	P	50	Beluga River	1962	Gas	P
12	Walakpa	1980	Gas	P	51	Ivan River	1966	Gas	P
13	West Sak	1969	Oil	UD	52	Lewis River	1975	Gas	P
14	Point Thomson	1977	Oil, Gas	UD	53	Stump Lake	1978	Gas	P
15	Northstar/Seal Island	1984	Oil	UD	54	Pretty Creek	1979	Gas	P
16	Flaxman Island	1975	Oil	UD	55	Cannery Loop	1979	Gas	P
17	Umiat	1946	Oil	UD	56	Katalla (Gulf of Alaska)	1902	Oil	ABND
18	Fish Creek	1949	Oil	UD	57	Redoubt Shoal	1968	Oil	UD
19	Simpson	1950	Oil	UD	58	Sunfish	1991	Oil	UD
20	Mikkelsen	1978	Oil	UD	59	Sterling	1961	Gas	SI
21	Gwydyr Bay	1981	Oil	UD	60	Falls Creek	1961	Gas	UD
22	Tern Island	1983	Oil	UD	61	West Foreland	1962	Gas	UD
23	Hemi Springs	1984	Oil	UD	62	North Fork	1965	Gas	UD
24	Colville Delta	1985	Oil	UD	63	Nicolai Creek	1966	Gas	SI
25	Hammerhead	1986	Oil	UD	64	Birch Hill	1967	Gas	UD
26	Sandpiper Island	1986	Oil	UD	65	Moquawkie	1965	Gas	SI
27	Badami	1990	Oil	UD	66	Albert Kaloa	1968	Gas	UD
28	Kuvlum	1992	Oil	UD	67	N. Middle Ground Shoal	1964	Gas	UD
29	Fiord (Colville Delta)	1992	Oil	UD	Abbreviations P = producing UD = undeveloped ABND = abandoned SI = shut in  = discovered prior to competitive leasing, 12/59				
30	Kalubik (Colville Delta)	1992	Oil	UD					
31	Cascade	1993	Oil	UD					
32	Sourdough	1994	n/a	UD					
33	Meade	1950	Gas	UD					
34	Wolf Creek	1951	Gas	UD					
35	Gubik	1951	Gas	UD					
36	Square Lake	1952	Gas	UD					
37	East Umiat	1963	Gas	UD					
38	Kavik	1969	Gas	UD					
39	Kemik	1972	Gas	UD					

Table 10. *Compiled lease sale data through May 1994*

STATE SALES ONLY				
	Tracts offered ^a	Tracts leased ^b	Acres offered ^a	Acres leased ^b
Cook Inlet				
34 Sales ^c	4,889	2,756	10,412,283.20	5,012,400.63
North Alaska ^d				
31 Sales ^e	3,202	1,590	13,416,980.62	5,842,423.45
FEDERAL SALES ONLY				
Cook Inlet				
3 Sales ^f	428	100	2,411,916.60	568,464.00
North Alaska ^d				
11 Sales	17,153	1,065	100,048,814.15	6,785,239.00
STATE AND FEDERAL SALES				
68 State Sales	9,018	4,654	26,686,901.87	11,611,494.55
21 Fed. Sales	25,078	1,618	144,382,217.75	9,894,273.00
Total:	34,096	6,272	171,069,119.62	21,505,767.55
PERCENTAGES OF TRACTS LEASED TO TRACTS OFFERED				
	Cook Inlet only	North Alaska only	All areas	
State	56.37%	49.66%	51.61%	
Federal	23.36%	6.21%	6.45%	
State & Federal	53.71%	13.04%	18.40%	
PERCENTAGES OF ACRES LEASED TO ACRES OFFERED				
	Cook Inlet only	North Alaska only	All areas	
State	48.14%	43.54%	43.51%	
Federal	23.57%	6.78%	6.85%	
State & Federal	43.52%	11.13%	12.57%	

^aIncludes all tracts or acreage; new and reoffered^bIncludes some released tracts or acreage^c27 CI sales plus the CI portions of 7 other sales^dNorth Alaska: entire North Slope onshore (including NPRA), Beaufort Sea, and Chukchi Sea^e29 North Alaska sales plus the North Alaska portions of 2 other sales^fIncludes one reoffering sale, RS-2**Note:** Number of active state leases (as of 5/94): 1,148

Number of producing state leases (as of 5/94): 282 (about 12 more have produced in past)

Number of active OCS federal leases (as of 2/94): 334 (no OCS leases produce)

Number of active onshore federal leases (as of 5/94): 155

Number of producing onshore federal leases (as of 5/94): 35

Table 11. *Hydrocarbon deposit summaries and well counts through April 1994*

CURRENTLY PRODUCING FIELDS				NONPRODUCING DEPOSITS				ALL DEPOSITS
Area	Oil	Gas only	Total	Area	Shut in	Undeveloped	Total	GRAND TOTALS
N. Alaska	9	3	12	N. Alaska	0	27	27	39
Cook Inlet	7	9	16	Cook Inlet	3*	8	11	27
Other	0	0	0	Other	1**	0	1	1
Total producing fields:			28	Total of other deposits:			39	67

*Sterling, Nicolai Creek, and Moquawkie

**Katalla Field (Gulf of Alaska) produced briefly and is now considered abandoned

CURRENTLY AND PAST PRODUCING FIELDS DISCOVERED POST-1959*				ALL DEPOSITS DISCOVERED POST-1959*			
N. Alaska	11	N. Alaska	31				
Cook Inlet	17	Cook Inlet	25				

*Commercial fields that were discovered after 1959, and have produced or are producing

*All deposits (commercial and noncommercial) that were made after 1959

Note: Competitive leasing began with State Sale No. 1 in December 1959. All discoveries found after that date, including commercially produced fields and noncommercial accumulations, are a result of the competitive leasing programs.

NUMBERS OF DRILLED WELLS* IN ALASKA

Areas	All types of wells	Exploration wells	Exploration wells post-1959
N. of 68° latitude ^b	2,911	350	335
S. of 68° latitude ^c	1,146	401	337
Entire State Total:	4,057	751	672
Cook Inlet Only ^d	973	266	248
Northern Alaska ^e	2,911	350	335
N. Alaska & C.I. Total:	3,884	616	583

* State and Federal, onshore and offshore

^b Includes new field wildcats, new pool wildcats, and outpost-extension wells^c Entire North Slope onshore (including NPRA), Beaufort Sea, and Chukchi Sea^d Rest of state other than (c)^e Just Cook Inlet, defined by lat 58.5°-62° and long 149°-153.5°^f Same as (c)

Table 12. *Historical percentages and success ratios through April 1994***PERCENTAGES OF TRACTS LEASED THAT WERE ACTUALLY DRILLED BY EXPLORATORY WELLS**

	Exploratory wells drilled ^a	Total tracts leased ^b	Calculated percentage
Northern Alaska	335	2,655	12.6%
Cook Inlet	248	2,856	8.7%
Entire State	672	6,272	10.7%

^aWells drilled after December 1959, the beginning of competitive leasing^bState and federal tracts leased**PERCENTAGES OF TRACTS LEASED THAT ARE BEING COMMERCIALY PRODUCED**

	Producing leases ^c	Total tracts leased	Calculated percentage
State	294	4,654	6.3%
Federal	35	1,618	2.2%
State and federal	329	6,272	5.2%

^cCurrently producing or have produced in the past**PERCENTAGES OF TRACTS OFFERED THAT ARE BEING COMMERCIALY PRODUCED**

	Producing leases ^c	Total tracts offered	Calculated percentage
State	294	9,018	3.3%

REGIONAL EXPLORATION WELL SUCCESS RATIOS

Area	ALL DEPOSITS POST-1959 Success ratio	ALL COMMERCIAL FIELDS, POST-1959 Success ratio
Northern Alaska	31/335 x 100 = 9.2%	11/335 x 100 = 3.3%
Cook Inlet	25/248 x 100 = 10.1%	17/248 x 100 = 6.9%
Entire State	56/672 x 100 = 8.3%	28/672 x 100 = 4.2%

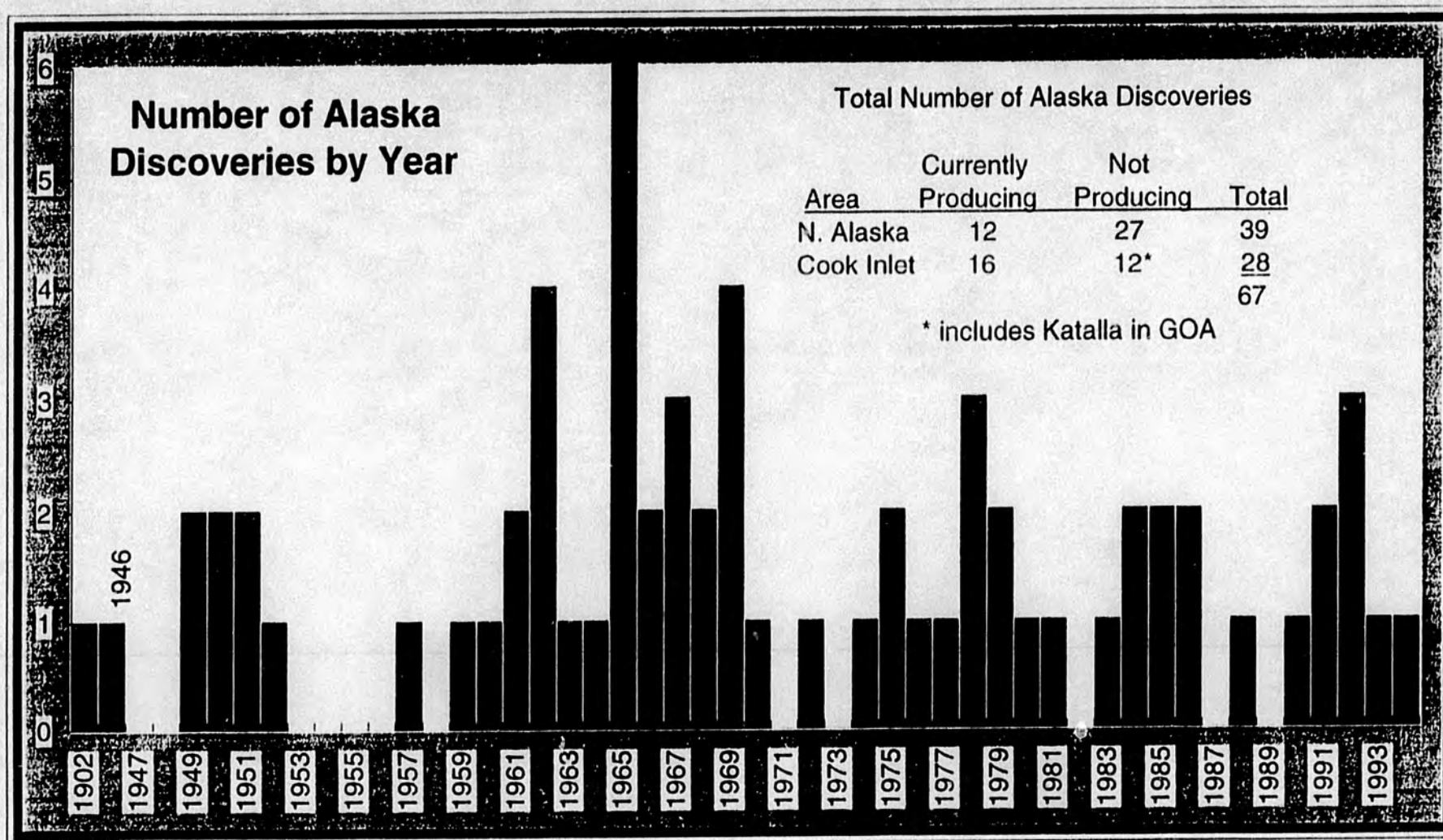


Figure 3. Number of Alaska discoveries by year through April 1994.

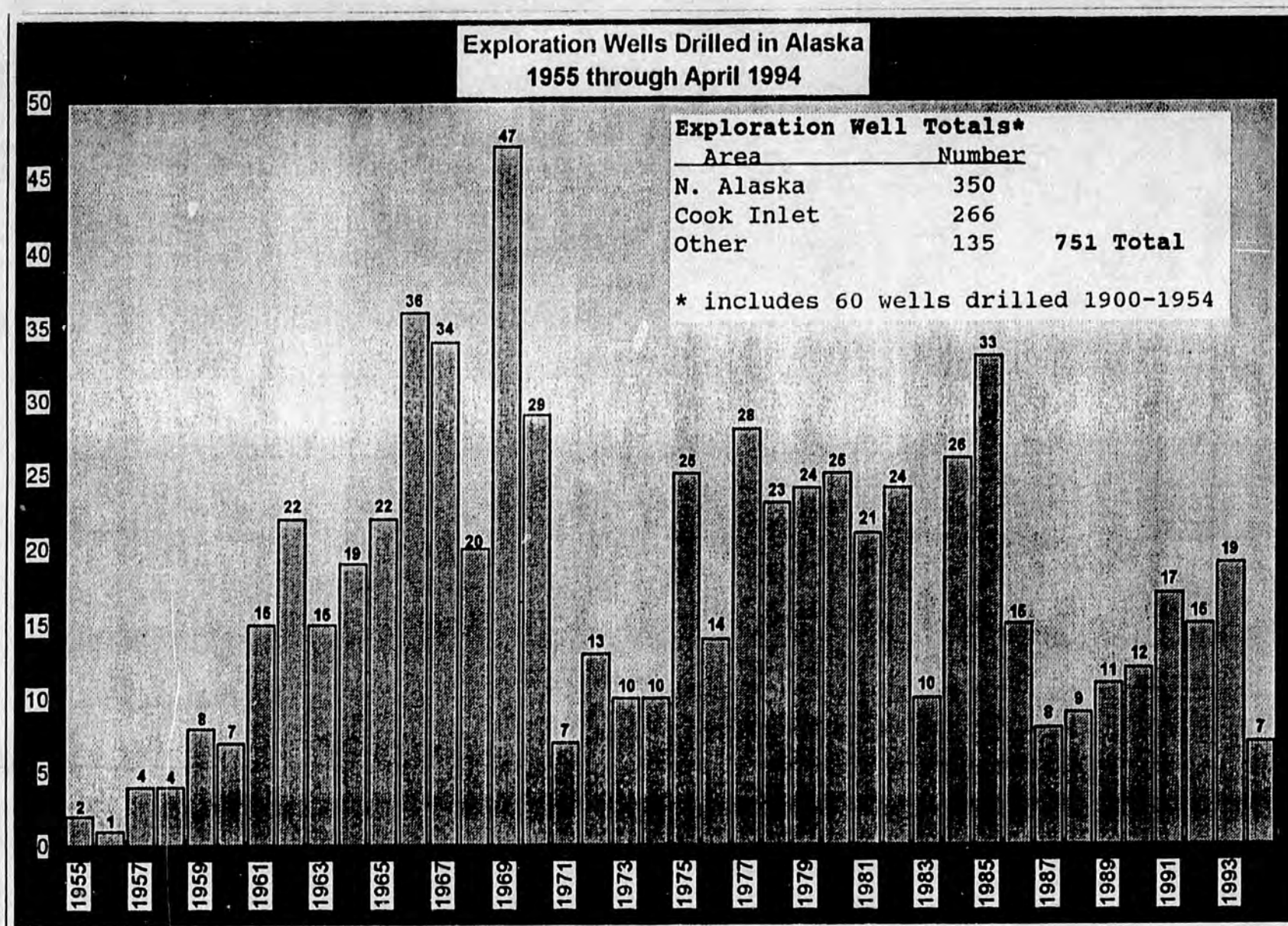


Figure 4. Exploration wells drilled in Alaska through April 1994.

**PERMITTING OIL AND GAS OPERATIONS IN ALASKA-
HOW IT HAS CHANGED, HOW IT COULD BE IMPROVED**

**A presentation to the
OIL AND GAS POLICY COUNCIL**

**prepared by
LGL ALASKA RESEARCH ASSOCIATES, INC.
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**for
BP EXPLORATION (ALASKA) INC.**

October 12, 1995

Good Morning. When I was asked by BP Exploration (Alaska) Inc. (BPXA) to speak with you about the State regulatory requirements governing oil and gas, and to make recommendations about how the State could ease the cumbersome permitting process and improve its long term attractiveness to the oil and gas industry, I asked why me? And when I was told that it was because I was an old-timer, I was startled. It dashed that sense of youth I've had since moving to Alaska in the early 70's. Then I realized that not only did I arrive pre-pipeline, but pre-404 wetland regulations, and pre-Alaska Coastal Management Program (ACMP) consistency determinations. I moved here about the time of the first environmental impact statement, hardly aware of the role it would play in the long run. Indeed things have changed. But not everything. I still love this State and hold on to the belief that big things can be accomplished and its beauty preserved. But this is probably more of an Alaskan trait, an old fashioned pioneering spirit, than a sign of youth. It is what keeps so many of us here for the duration. And it is what will give those in both government and industry the strength to challenge and improve the status quo as we work together to make the regulatory process more manageable while still maintaining the highest standard of environmental protection.

The oil industry is obviously vital to Alaska, a State that has relied on the development of various natural resources for generations. It is proper that the oil industry, and other natural resource industries, be regulated. But the regulatory process has become so complicated that it is often unreasonably burdensome. While the federal regulatory process shares much of the blame, changes at the State level can make a difference in the future. So my goal today is to make some recommendations to this committee as it sorts out options on how to ease industry's navigation through the regulatory process.

My recommendations include: Establish a single, centrally-located organization with the expertise to administer the State regulatory programs for oil and gas. Provide regulators with sufficient training in the operations of the oil and gas industry so that they understand what they are regulating. They must understand the both the big picture and the details they are responsible for. Allow the State to partner with industry in the design and construction of proposed projects. Be proactive with respect to federal issues, regulatory or policy, that affect oil and gas operations in Alaska. And critically review existing State regulations to make sure they are still appropriate.

My recommendations are not the result of a study, per se, but in addition to drawing on my own experience, I interviewed eighteen people with both current and past experience navigating the regulatory maze. The group I interviewed was definitely weighted towards industry because I learned, after I started, that the State is going to make their own presentation on the regulatory process to this council and that it was agreed the two would be made separately. Still the input from the two State employees with whom I spoke at great length was really valuable. I was impressed that their analysis of the problems very much reflected what industry representatives were telling me. People were very generous with their time, and I found real support for the initiative Governor Knowles is taking to bring about effective change.

Some historical background gives context to what we face today. The first commercial quantities of oil and gas were discovered on the Kenai Peninsula in 1957 - the Swanson River oil field. It took only two years to bring this field into production. There were a number of other small fields discovered over the next decade. The entire development process - delineation, engineering, and permitting - took about two years for each of them. One of the last reservoirs, the McArthur River Field, was discovered in 1965 and was producing by 1967. A year later, 1968, Prudhoe Bay was discovered. Then came the first of many federal environmental laws that have shaped both State and federal permitting today, the National Environmental Policy Act of 1969 (NEPA). NEPA codified the public input process and the Environmental Impact Statement (EIS) requirements that we are so familiar with.

NEPA was followed by the Marine Mammal Protection Act of 1972, the Coastal Zone Management Act of 1972, and the Endangered Species Act of 1973, among others. In the midst of all of this, the great environmental debate over Prudhoe Bay and the Trans-Alaska Pipeline System (TAPS) was taking place, dividing the State and the nation. A tie-breaking vote by Vice President Spiro Agnew in 1973 meant the passage of The Trans-Alaska Pipeline Authorization Act allowing construction of TAPS to begin. Finally, in June 1977, nine years after Prudhoe Bay was discovered, oil began flowing through the Trans-Alaska Pipeline. On the heels of Prudhoe's start-up during the winter of 1977-78, the Endicott oil field was discovered. It came on line almost ten years later, October 1987. Lead times required to go from discovery to production have increased five-fold over the last four decades. To his credit, Governor Knowles is committed to improving the situation.

The increase in the time and cost of permitting oil and gas operations in Alaska reflects two problems. First there is the regulatory maze. It continues to grow. When you think it can't get any more difficult to navigate, it does. It requires a large, technically specialized staff for both the State and industry. There are also the compliance costs that increase exponentially when you add requirements such as specialized modeling of air emissions, or long term biological monitoring programs - costs that are not always commensurate with any environmental benefits.

Secondly, there are people issues. Philosophical differences, individual personalities, and conflicting agendas can affect the working relationship between permittee and regulator. Too often since 1969 and the advent of NEPA, adversarial relationships have developed and made the permitting process contentious and slow. It is a gross oversimplification, but in general, regulators, particularly those with the Alaska Departments of Fish and Game (ADF&G) and Environmental Conservation (DEC), or the U.S. Fish and Wildlife Service (USFWS) and the Environmental Protection Agency (EPA) on the federal side, have not trusted industry with their profit motive, and industry has not respected regulators whom they have viewed as more interested in protecting specific environmental agendas and imposing punitive stipulations than in seeking legitimate solutions to environmental issues. Over the years, this has hindered productive cooperation, and killed or delayed oil and gas projects.

Both the regulatory issues and the people issues, issues of trust and cooperation, should be addressed by this commission as it formulates recommendations aimed at

improving the attractiveness of Alaska to the oil and gas industry. I want to touch first on the regulatory and policy issues.

There is no question that the sheer volume of regulations and the extensive and often duplicative permitting processes are time-consuming and increase development costs. There are overlapping jurisdictions, local, state and federal, that review primarily the same activities. This limited list of the major federal environmental acts shows the breadth of the regulatory issues: National Environmental Policy Act (NEPA), Clean Air Act (CAA), Clean Water Act (CWA), Safe Drinking Water Act (SDWA), Resource Conservation and Recovery Act (RCRA), Superfund Act (CERCLA), Federal Insecticide, Fungicide and Rodenticide Act (FIFRA), Coastal Zone Management Act (CZMA), Endangered Species Act (ESA), Marine Mammal Protection Act (MMPA), and Toxic Substances Control Act (TOSCA).

Follow this with a list of the major operating permits issued by the State of Alaska - permits to drill oil wells, permits for injection wells, anadromous and non-anadromous fish stream permits, lease operation permits, right-of-way (ROW) leases, water rights and temporary water use permits, gravel sales contracts, air quality permits (there are several), non-hazardous solid waste disposal permits, water quality section 401 certifications of federal section 404 Clean Water Act permits, ACMP consistency determinations, and oil discharge prevention and contingency plan approvals. Couple these with local borough land use permits, development permits, and coastal management programs and it is no wonder that permitting can take a considerable amount of time.

More often than not, the different jurisdictions review permits on different time lines, and project changes required by one regulatory entity affect the review by another regulatory entity, especially requested design changes or operating restrictions. And when a project proposal is still fluid, as most are by necessity, changes requested by the permittee can throw regulators and the process for a loop in all the jurisdictions. It is not uncommon for the regulatory review clock to be reset at zero following project changes.

This growth in regulation reflects a sincere effort at many levels to protect both human health and the environment. There have been definite gains in areas of waste handling and waste minimization as a result of regulation. Regulatory issues surrounding wetlands protection have precipitated new ways of minimizing habitat disturbance. Generally every regulation has been written for a purpose. Still, something is wrong when the original Kenai oil fields, circa late 1950's and 1960's, took only two years to permit and just recently it took an applicant 15 months to permit a 1.5 mile road in the North Swanson River area that covered no wetlands and 50% of it was on an existing right-of-way. Something is wrong when it takes 15 months to renew a single air permit (with no changes) that should have been completed in less than 60 days. Why now has the State decided to require modeling of existing sources of air emissions? This is expensive, and it is more onerous than the federal requirements for which the State is in the process of assuming primacy. The Alaska standard for total aqueous hydrocarbons (TAQH) is 100 times more restrictive than the typical hydrocarbon restriction in the water quality standards of the other 49 states; it is

not clearly supported by science, it is selectively enforced only on the oil industry, and it is the sort of regulation that drives people in the industry nuts.

This focus on regulations begs a discussion of one of the major differences between the State and industry - their reaction time, their ability to initiate change and to incorporate change. Regulations and regulatory decisions are set in stone, but industry's plans and capabilities are not. This has caused problems during the permitting process, and solved problems as well. A good example is directional drilling. When permitting first began on the proposed Niakuk development, directional drilling allowed wells to extend approximately 5,000 feet from their surface location. To reach the farthest offshore portion of the reservoir, the proposed production scenario included an offshore drilling island connected to shore by a small causeway. This ultimately proved impossible to permit due to regulatory objections to the causeway. An alternate onshore scenario was then proposed and ultimately permitted. The physical limitations imposed by not having an offshore drilling pad meant that a significant portion of the offshore reserves could not be produced. Since that time directional drilling capabilities have increased and are now in the range of 15,000 feet. This extended reach has increased the anticipated production from Niakuk. The point here is that industry is progressive, and their staff are allowed and encouraged to be so.

Industry staff have a wide open door to try new things and they can incorporate changes quickly. This ability is a two edged sword. While it promotes creative solutions, it has been the basis for some distrust between industry and its regulators. Industry can change project designs, they can do things they originally said they could not do, and sometimes they cannot do things that regulators assume they should be able to do if only the regulators stand firm long enough against what industry has proposed. It also means that some regulations are no longer appropriate or flexible enough to accommodate change in the oil industry.

Given the explosion of regulations over the years, it would be a worthwhile exercise to review them and assess whether or not they meet their intended purpose. They should also be examined with an eye for clarity, reasonable time frames for permitting, and simplified procedures for compliance. Industry representatives repeatedly tell me that they are not asking that their projects not be regulated. They want the permitting process to be simplified, the regulatory requirements to be clear and supported by science, and they don't want compliance requirements that are cost prohibitive.

Obviously this would be a huge task and so priorities have to be set. Many people I have spoken with have suggested different regulations or agencies they believe should be given review priority. They cover the gamut from Title 38 which outlines DNR land use regulations, to the ACMP, but most often it is the myriad of Department of Environmental Conservation regulations that are cited as those causing the greatest problems - in particular, the new Title V air quality regulations, the State water quality standards, and site close-out procedures.

With respect to the air regulations in particular I heard much about the fact that DEC ignored industry's input, and that the regulations are so unclear that even DEC staff

could not agree on how to interpret the regulations at a meeting where they were supposed to explain them to industry.

Separate from the regulations themselves, I heard about DEC's new pay-per-use structure for air quality permits. It has some definite benefits, one of them an additional source of much needed funding for an agency saddled with broad responsibilities and in need of additional staff to keep up with all the permits it requires. There is also great hope that the pay per use system will also force greater efficiency on DEC staff as they account for, and bill, their time.

Early reviews of this process vary. Some in industry are genuinely pleased with its implementation. Others are upset for one of two reasons. Either they feel they are being double-taxed, or they worry that without a standardized fee structure, it is subject to abuse. One company cited an annual equipment inspection that their contract engineer estimated would take 8 hours. The DEC official who did the inspection billed the company for 60 hours at \$65/hour. When companies call to ask for explanations of their billings, or even questions about who to contact regarding specific permits, they often don't get a satisfactory response, but they do get charged additional fees for their inquiries. And then they get small invoices that are hardly cost effective to process.

In addition to setting standard fees for regular, predictable activities, it has been suggested that compliance reviews could be privatized. DEC could provide an oil company with a list of approved contractors for compliance reviews. The company could compare costs and pick the contractor of their choice. This would also insure more timely inspections and let DEC focus greater resources on their permit review efforts.

Gene Burden, DEC Commissioner, has acknowledged many of the problems with DEC and with the Title V regulations in particular. While improvements are not readily apparent, Commissioner Burden is trying to accomplish some of the needed changes through reorganization of the department. DEC is now in the midst of that reorganization. It is not going particularly smoothly from the perspective of industry or the regulators with whom I spoke. But reorganizations take time, and people in industry and government are willing to give it time, especially the oil companies who have been through a few reorganizations of their own.

The Alaska Coastal Management Program is another regulatory program that deserves review. In some respects it is working well, especially since the coordinated permit review process was implemented by the State in 1985. The ACMP definitely meets the purpose for which it was originally established, giving the State an avenue to comment on major federal lease sales and development projects affecting the coastal zone. The coordinating role given to the Department of Governmental Coordination (DGC) is also working well. It has served as an avenue to bring State regulators together on a given project and to facilitate consensus.

What is unique about the ACMP is that it depends on consensus. Sometimes, however, consensus cannot be reached when a single dissenting agency effectively has veto power. This can be the case even when they do not otherwise have statutory

permit authority over a given project. The ACMP process also allows agencies to attach stipulations to a project that they would not otherwise have the authority to require. These are referred to as "homeless slips". This opportunity is most often used by the ADF&G. The most recent example was their effort to include a stipulation requiring a polar bear interaction plan on the consistency determination for the Badami ROW permit. Not only does ADF&G not have the regulatory authority for this, except through the ACMP, but polar bears are managed by the federal government. BPXA never objected to developing the plan, and in fact are doing so. The objection was over its inclusion as a stipulation on a State permit.

I could go on about regulatory problems. However, the major point I want to make is that no matter what is done in terms of regulations, it is still people who make things happen, and they need to have some common goals to work effectively together. Agencies with different mandates, and regulations that can be used by individuals as tools for delay, provide ample opportunities for conflict between environmental and economic interests; between different public interests, and between industry and agency. Without a mutual interest in resolving problems to allow a project to proceed, it won't be accomplished easily.

Too often we, either industry or agency, have not approached the permitting process as a win-win situation, especially at the staff level. If a permit was issued, for whatever reason, some regulators felt like losers; when a permit was significantly delayed, or not approved as proposed, the permittee felt like a loser; and when a permit was issued after much negotiation and the inclusion of costly stipulations, everybody felt like losers, or neutral at best. Historically, this last situation has been true for large projects, and it is not good. It is like a troubled marriage. Both parties must share the blame, and both parties must be willing to change if they want to improve the relationship.

Everyone I spoke with, industry and agency representatives alike, emphasized that attitude, on both sides, is a key factor. But attitude cannot be legislated. When attitude precipitates adversarial relationships and an "us versus them" battle, it can be a crippling factor in the permit process. Certainly, when this happens it is a frustrating experience for all involved. Attitude, when there is respect, cooperation, openness and a common goal, can also be incredibly productive. And there are good examples of this - Alyeska's experience with the Joint Pipeline Office (JPO), and especially BPXA's current effort to permit the Badami development.

The example of the JPO is worth looking at because it is, for the most part, an efficient, productive group of regulators. The JPO was set up administratively to bring together representatives of DNR, ADF&G, DEC and DGC with federal representatives of the Bureau of Land Management (BLM) and EPA. Their mission was to bring efficiency to the permitting and compliance requirements for operation and maintenance of the Trans-Alaska Pipeline. JPO representatives work as a team with a clear goal, housed under one roof. Centralization and accessibility facilitates meetings whether they are planned or impromptu. This is in contrast to a North Slope project where an applicant must coordinate with DNR's Division of Land in Fairbanks, the DNR Division of Oil and Gas in Anchorage for lease operation approvals, and the DNR Division of Mining and

Water Management for temporary water use, also in Fairbanks; DEC representatives that may be in Anchorage, Fairbanks, or Juneau; DGC in Fairbanks, and ADF&G in Fairbanks. The exception is when a North Slope operator is trying to permit a right-of-way, then they must also deal with some of the players at the JPO, but not all, not ADF&G for example. The one-stop shopping concept afforded Alyeska would be welcomed by many in industry, except perhaps for its price tag, an issue I didn't specifically discuss with industry.

When I recently asked a member of the JPO why it seemed that the different agencies were so cooperative, I was assured that they weren't always. As in any office there were personalities that clashed and some infighting among different groups that did not always benefit the applicant. As a rule, however, they found ways to solve their differences because they still had to face each other at the coffee pot in the morning. They could disagree, but they couldn't hide out at their own agency and get encouragement to continue a fight. Working directly with their counterparts in other agencies has meant that staff are more careful not to take a position unless they can provide a rationale for it, because their peers in other agencies will challenge them.

Operating as a team, and being able to focus on one industry, the JPO staff have developed a degree of trust and a greater appreciation of each other's technical abilities. I have had a DNR or DEC representative tell me that if a certain Alyeska request is OK with ADF&G it's OK with them, and vice versa. The disappointing aspect of the JPO right now is that as a consequence of their reorganization, DEC has pulled out with the exception of their oil spill response person. Their participation is missed both by Alyeska and by DEC's sister agencies. Almost one stop shopping is not as good as one stop shopping.

Where there are mutual goals, people tend to be open about their concerns and their needs. This openness allows regulators to better understand operational costs and restrictions, and it allows operators to understand regulatory constraints. A willingness on both sides to be flexible with respect to project timing, project design, and construction methods is important. Consideration of operational and cost restrictions is also important. A centralized organization, reflecting a team approach to regulating oil and gas development, would be beneficial if it worked towards these goals.

It was a lesson to the JPO staff that Alyeska's poor showing in the 1991 Governmental Accounting Office (GAO) audit was a reflection on them as well. It brought focus to the fact that they had a vested interest in Alyeska's success. If Alyeska's operations improved, it meant that they were doing their job well too. In essence there has to be a sense of partnering between agency and industry. At times it may seem a fine line between partnering and protecting the public interest, but if we want a win-win situation, both the State and the oil and gas industry have to have a stake in making future developments a reality. BPXA and the State are showing this is possible with their permit work for the Badami development, a story of its own, which will follow this talk.

The greatest drawback with the JPO organization from the perspective of some of its staff is that they are viewed as rubber stampers by peers in their home offices. Many in

Alyeska would attest to the fact that this is not the case. They are experts in their fields who have taken the time to understand and actively shape industry's operations. The management at JPO has gone to great lengths to ensure they understand their roles, their goals, and Alyeska operations.

Strong management is important in any organization. Employees must understand the overall goals and mission of an organization, and where their role fits in. With respect to the State, the Governor may encourage new developments, his commissioners may support him, but if the staff do not, they can effectively throw a monkey wrench in the works. At the permitting level, staff can effectively set policy that does not reflect policy at the leadership level. And in government, most staff know that they can outlast their management. Effective leadership requires that there be close ties and constant communication - up and down - between management and staff.

It is critical that regulators understand why their Governor supports keeping Alaska competitive for oil and gas dollars. It is important that they understand why marginal fields are significant in the near term. Education in this regard is crucial. It is important that State management, and industry, let regulatory staff know they have a stake in the outcome, and that if permitting efforts go smoothly they get credit not only for allowing development to proceed but for ensuring that it proceeds in an environmentally sound fashion. This educational effort should be a cooperative effort with industry providing support to the state.

Technical qualifications are also important. Industry and the State both benefit from having strong, technically-qualified regulators for two reasons. One is that you have to have a technically strong staff who maintain thorough administrative records to withstand third party lawsuits. Third party lawsuits are going to remain a fact of life. Secondly, when people know what they are doing, no matter whom they work for, they are typically easier to deal with. When someone regulating industry does not have a good grasp of both the big picture and the specific issues, they are reluctant to make a decision. They will typically focus on one issue they do understand, often distorting its significance, and lose the perspective necessary to review the project as whole. Still focusing on DEC, there is a feeling that because of the Exxon Valdez oil spill, DEC was forced to grow too large too quickly to recruit well-trained, technically-qualified staff, and that some of today's conflicts with the agency are a result of this.

Not only must the State continue their efforts to hire technically qualified staff, but they must provide educational opportunities, especially when dealing with specialized industries whether it be oil and gas, mining, fishing or timber. Industry has to take on some of the responsibility in this regard. The development of a joint, formalized training program on different aspects of industry operations and regulatory restrictions, and how the two can be meshed to promote safe development, would be beneficial to many staff. Industry too has a role to educate, and I know that BPXA has made an effort to put on workshops about the oil industry. They have been well received by regulators, but the responsibility must be shared.

Finally, the excessive permitting burdens placed on industry are not the sole responsibility of the State. The federal government is often to blame for the lion's

share of the problem. For large projects, the ultimate delays are usually caused by the federal regulatory process, particularly the permits required under the CWA, the CAA and the numerous acts covering wastes and discharges. The State, however, can choose to influence these permitting processes and can also be proactive in influencing federal policy.

While the State is making a strong effort now, for example, to influence the federal wetlands mitigation policy, their effort is reactive. It would have been better had the State been proactive and started working the issue hard six to eight years ago. The State can also make a greater effort to get primacy for more federal regulations. They should be prepared to do it properly and not to establish a program more confusing or more restrictive than the federal program as has happened with the Title V air quality regulations. The goal of primacy should be to have a more efficient program that is more easily administered as part of the State's permit process. For the most part, it should not be used to make federal regulations even more stringent.

With regard to specific projects, once all the State permits have been issued, the State should not be afraid to take an active role in supporting the project during the federal review. They have a stake in the outcome. Their review has been thorough; they should be confident in defending their decision to allow development to proceed. They can work with industry, or sometimes on behalf of industry, to overcome obstacles in the federal permitting process.

This brings me back to the recommendations I suggest this council put forward with regard to permitting, so that the State is able to maximize the long term value of their oil and gas interests and continue to attract oil and gas investments in Alaska.

- (1) Consider establishing a single, centrally-located regulatory organization with the expertise to properly and efficiently regulate oil and gas activities as a team.
- (2) Partner with industry in the design and review of proposed projects. Let employees on both sides have a stake in its success.
- (3) Educate regulators about the industry they regulate. Make sure they clearly understand the state's interest in working with the oil and gas industry to keep it vital. Make sure they have, or can get, the technical qualifications to do their job well.
- (4) Be proactive with respect to federal actions, regulatory or policy, that affect the State.
- (5) Review regulations, particularly the most contentious ones. Make sure regulations are written clearly, that they can be scientifically justified, and work with industry during this review. Draw on their experience and expertise to know what is or is not feasible, and why.

I believe the trend of the ever increasing permitting times will change if there is a determination by individuals in the State, from top to bottom, to work with industry to facilitate the permitting process. Industry is willing and ready to help. The ongoing

effort to permit the Badami development is a case in point. Both BPXA and the State have changed their approach and within the existing regulatory framework are moving forward rapidly. Watching from the outside, it has been heartening to hear really positive comments about the Badami permitting experience from colleagues at the JPO and other regulatory groups, as well as from friends at BPXA. It illustrates the benefits of collaboration. The challenge is to create a framework that makes teamwork and expediency the rule not the exception.

State of Alaska
Department of Natural Resources
Division of Oil and Gas

**A Brief Discussion of Alaska's Oil and Gas Resource
Potential**

Key Illustrations

Presented on September 7, 1995

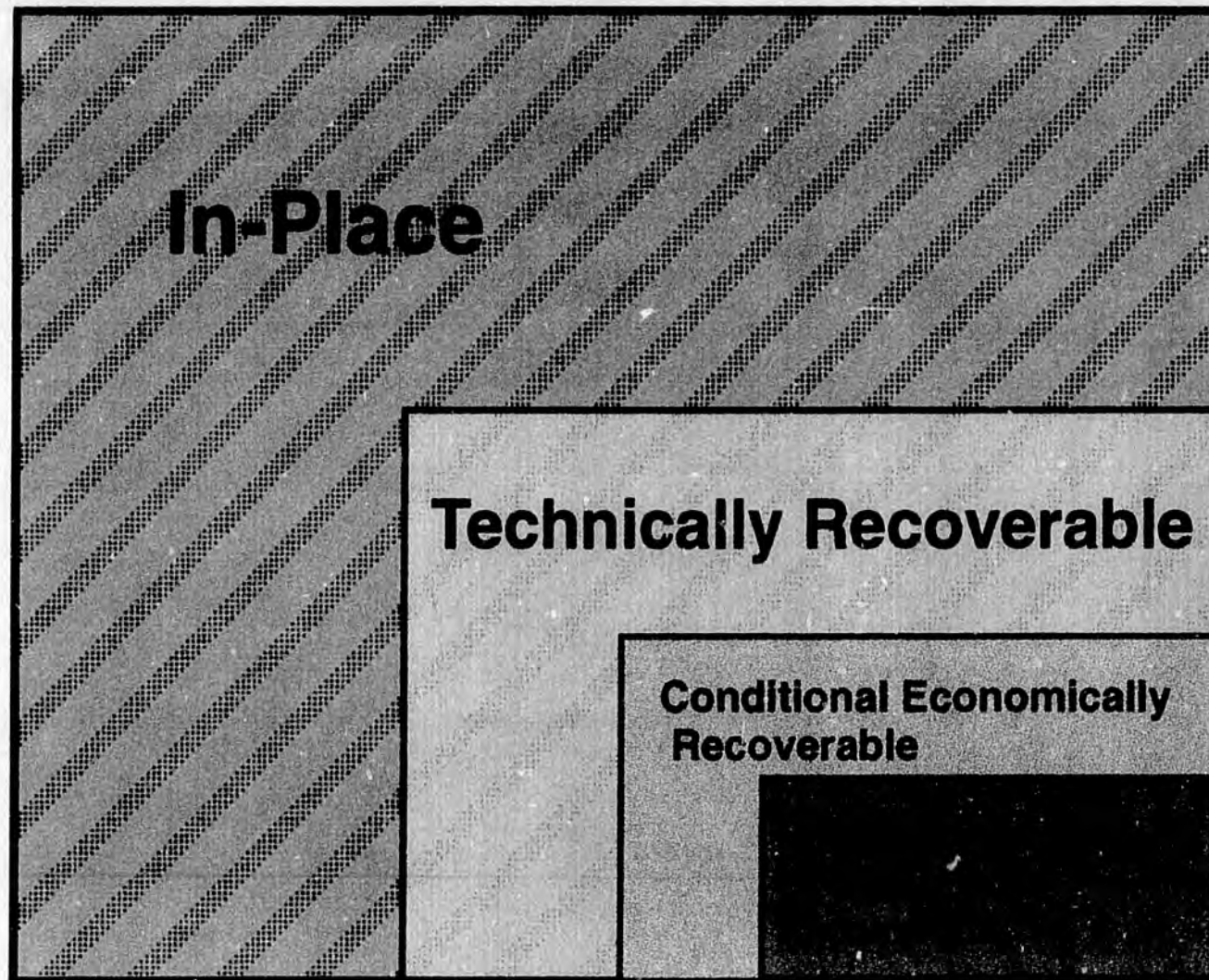
**Measured
(Proved)
Reserves**

**Inferred
Reserves**

Undiscovered Resources

Economic under existing conditions

**Possible additional recoverable oil
in known fields**



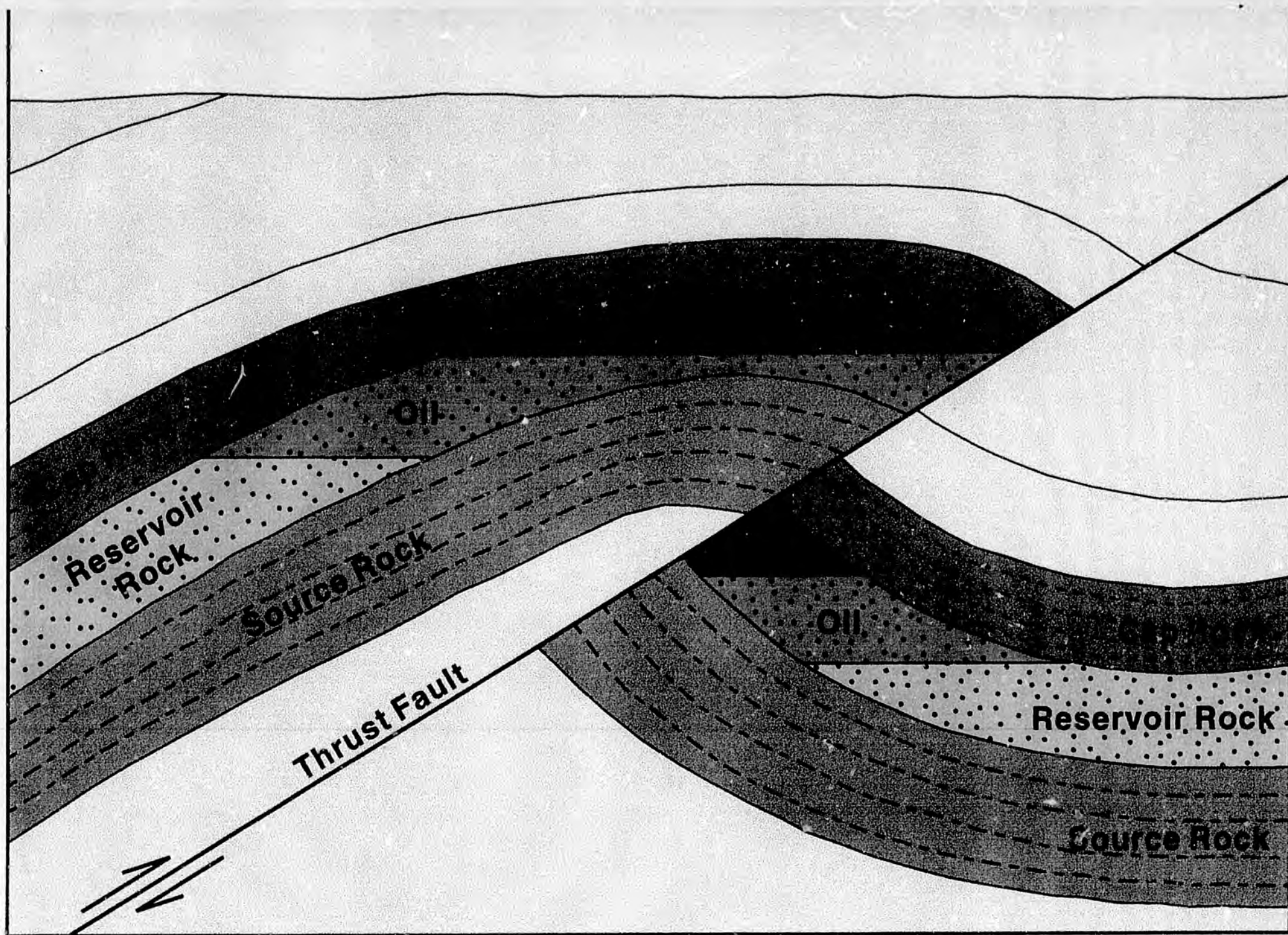
Known

Speculative

Unknown

Increased Number of Chance Weighted Assumptions

Different Types of Resource Estimates for a Given Area



Elements required for the creation of an oil and gas accumulation include Source, Reservoir, Trap and Timing.

A Geologic Play Assessment for In-Place Resources

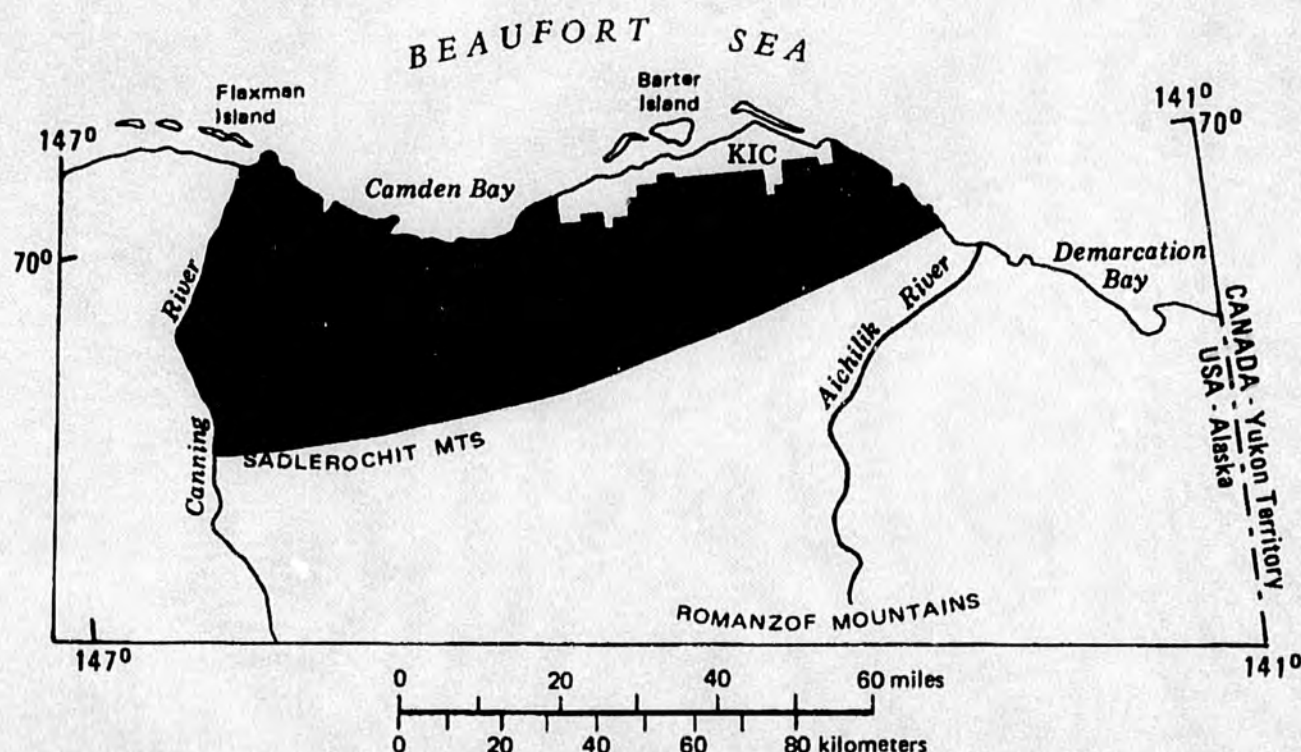
Output from the Computer

Gas fraction = 0.40 Conditional resources in place			
Fractile	Oil (million barrels)	Gas (billion ft ³)	BOE (million)
0.99	0.00	0.00	0.00
0.95	0.00	0.00	0.00
0.90	0.00	0.00	0.00
0.75	0.00	0.00	0.00
0.50	0.00	0.00	0.00
0.25	0.00	689.02	292.14
0.10	948.85	2927.37	1339.20
0.05	1927.34	5123.80	2619.52
0.01	5981.70	11366.90	7005.12

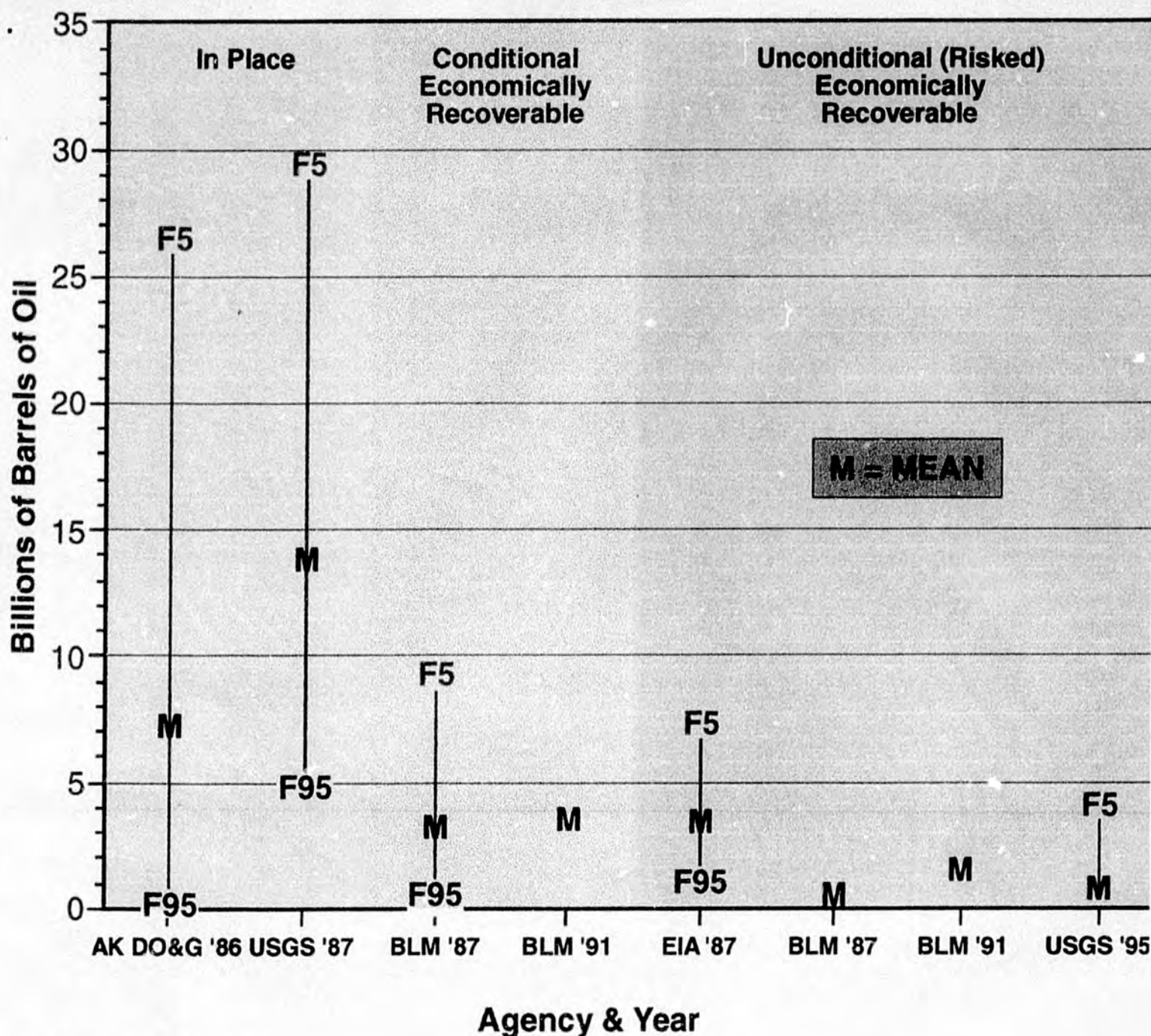
Deposit size Conditional, 100% oil		Deposit size Conditional, 100% gas	
Fractile	(million barrels)	Fractile	(billion ft ³)
0.99	11.112	0.99	15.476
0.95	41.465	0.95	53.727
0.90	70.171	0.90	148.026
0.75	174.012	0.75	417.946
0.50	538.918	0.50	1163.055
0.25	1323.921	0.25	2905.923
0.10	2925.320	0.10	5803.098
0.05	4333.508	0.05	7478.438
0.01	9932.547	0.01	14709.691

Input from the Evaluator

Attribute		Probability that attribute is favorable or present							
Play attributes	Hydrocarbon sources	1							
	Timing	1							
	Migration	1							
	Potential reservoir facies	0.5							
	Marginal-play probability	0.5							
Prospect attributes	Trapping mechanism	0.3							
	Effective porosity (>3%)	0.8							
	Hydrocarbon accumulation	0.4							
	Conditional-deposit probability	0.096							
Hydrocarbon-volume parameters	Reservoir lithology	Sand	1						
		Carbonate	0						
	Hydrocarbon mix	Gas	0.4						
		Oil	0.6						
	Fractiles Attribute		Probability of equal to or greater than						
			1.00	0.95	0.75	0.50	0.25	0.05	0
	Area of closure (x10 ³ acres)		0.6	3	10	12	15	30	100
	Reservoir thickness/vertical closure (ft)		5	50	125	200	350	500	750
	Effective porosity (%)		3	7	13	15	18	23	30
	Trap fill (%)		1	5	25	50	75	95	100
	Reservoir depth (x10 ³ ft)		5	8	10	12	18	22	28
Number of drillable prospects (a play characteristic)		2	4	4	5	8	10	20	



Areal distribution, input parameters, and resources in place for the Permian-Triassic Clastics North Play, Arctic National Wildlife Refuge, Alaska.



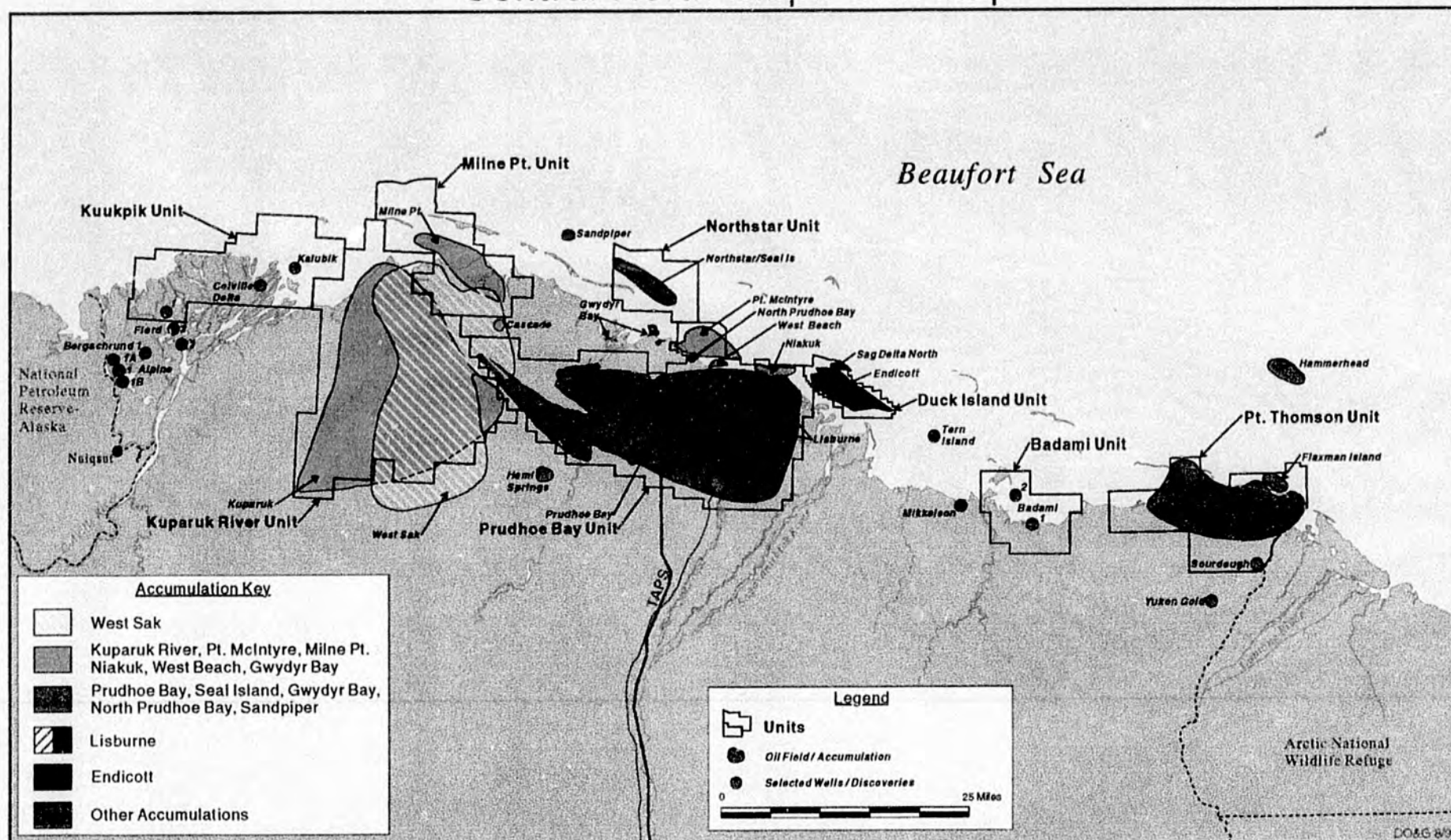
F95	Mean	F5	
0.08	7.22	26.52	AK DO&G in place 1986
4.8	13.8	29.4	USGS in place 1987
0.61	3.23	9.24	BLM Undiscovered conditional economically recoverable oil in 1987
	3.57		BLM Undiscovered conditional economically recoverable oil in 1991
1.2	3.45	7.35	EIA Unconditional (risked) economically recoverable oil 1987
	0.6137		BLM Unconditional (risked) economically recoverable oil 1987
	1.642		BLM Unconditional (risked) economically recoverable oil 1991*
0	0.898	4.129	USGS Unconditional (risked) economically recoverable oil in 1995

*Reflects a change in original probability from 19% to 46%

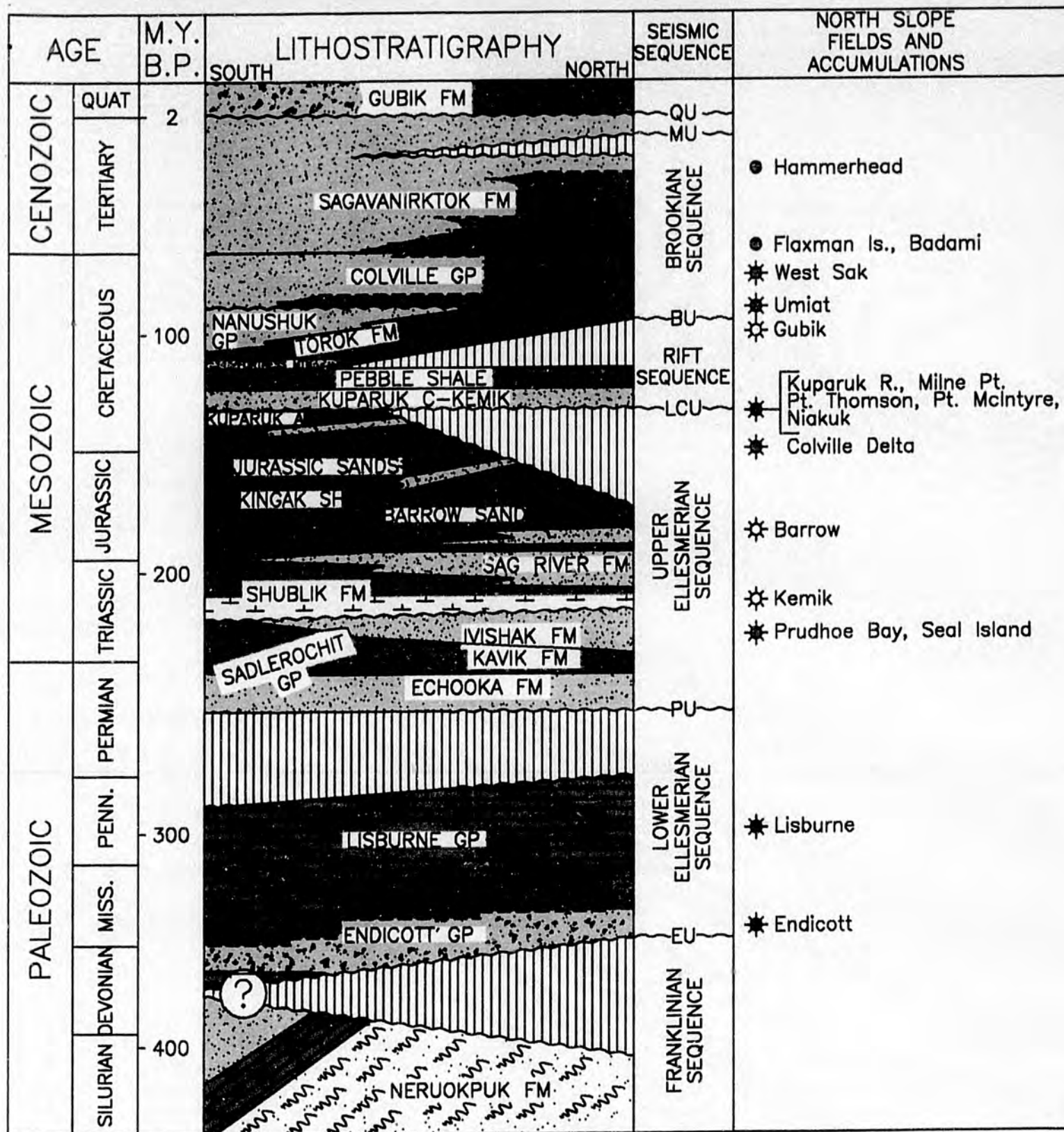
SOURCE: Alaska Division of Oil & Gas, June 1995

Estimates of Undiscovered Oil Resources in the Coastal Plain
of the Arctic National Wildlife Refuge 1986 - 1995.

Central North Slope Unit Map



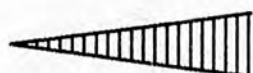
The State of Alaska makes no expressed or implied warranty regarding the accuracy of the information and data used in the preparation of this map. The State of Alaska is not responsible for any errors or omissions in the map. The State of Alaska is not responsible for any damages or losses resulting from the use of this map. The State of Alaska is not responsible for any claims or liabilities arising from the use of this map. The State of Alaska is not responsible for any claims or liabilities arising from the use of this map.



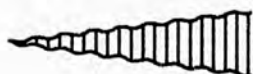
● OIL

★ GAS

★ OIL & GAS



DEPOSITIONAL UNCONFORMITY



EROSIONAL UNCONFORMITY



SANDSTONE



CONGLOMERATE



ARGILLITE



SHALE



LIMESTONE



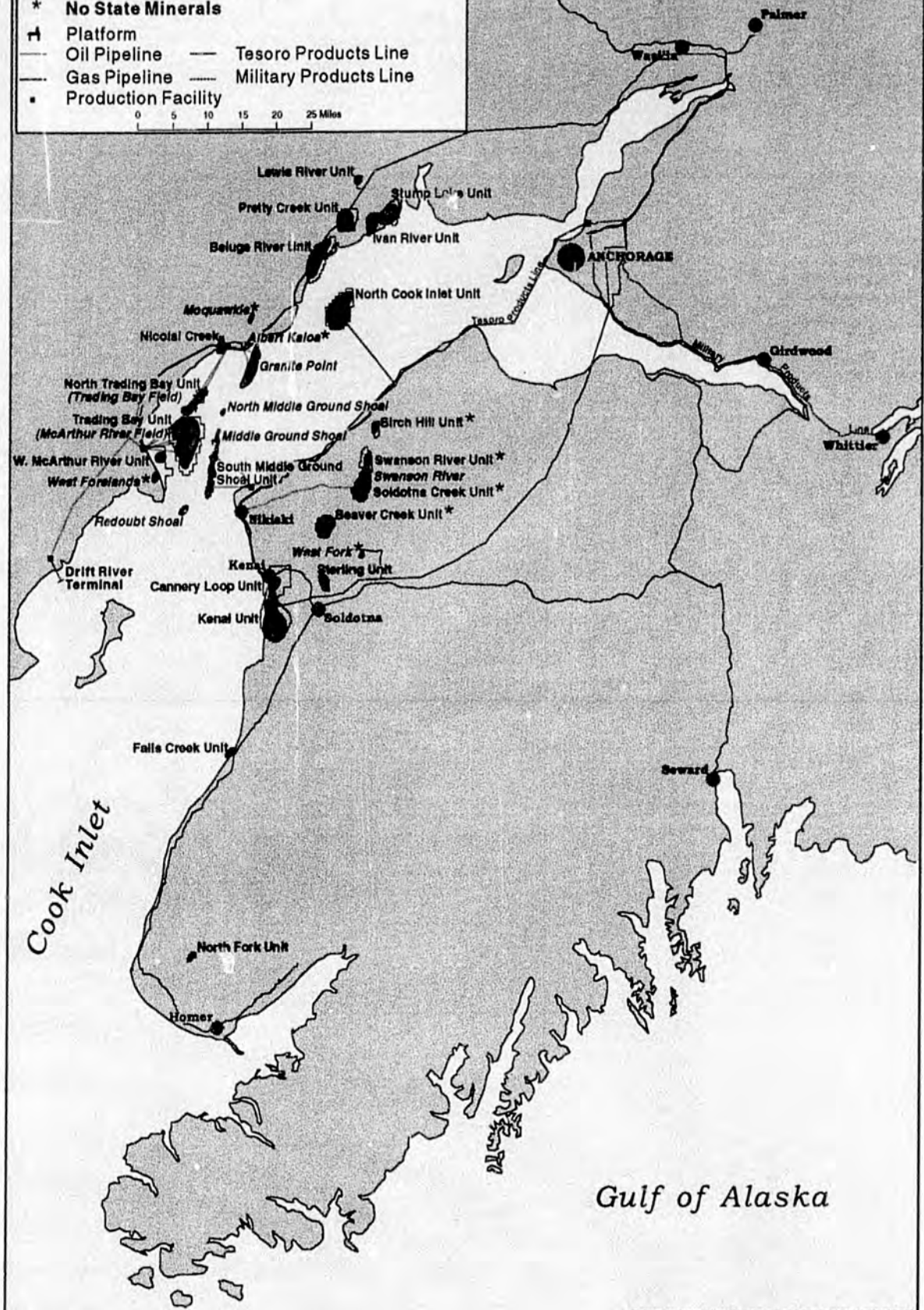
DOLOSTONE

Generalized North Slope Stratigraphic Column displaying oil and gas reservoirs and associated accumulations.

COOK INLET OIL & GAS MAP

- Units
- Oil Field / Accumulation
- Gas Field / Accumulation
- * No State Minerals
- ⌈ Platform
- Oil Pipeline — Tesoro Products Line
- Gas Pipeline — Military Products Line
- Production Facility

0 5 10 15 20 25 Miles



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

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

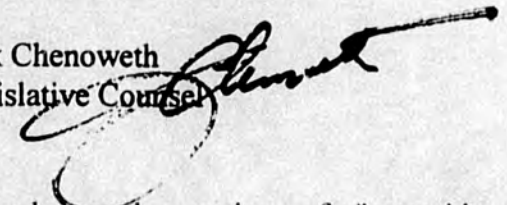
130 Seward Street, Suite 409
Juneau, Alaska 99801-2105

MEMORANDUM

December 6, 1995

SUBJECT: Areawide oil and gas leasing (Work Order No. 9-LS1341\A)

TO: Representative Norm Rokeberg

FROM: Jack Chenoweth
Legislative Counsel 

The enclosed draft introduces the notion of "areawide leasing" in proposed AS 38.05.180(dd), bill section 4 of the draft. A lot of discretion is left to the director of lands and the commissioner of natural resources to develop "areawide leasing" under the department's authority to develop and adopt regulations, and that may not be in line with your thinking. The control on the exercise of the department's authority under any regulations adopted should be, in my judgment, legislative direction to the department, given by law, that one or more particular geographical areas should be opened to "areawide leasing." The commissioner could propose areas for inclusion under "areawide leasing" in the department's annual submission to the legislature under AS 38.05.180(b).

In our phone discussion, you indicated that North Slope acreage located between the Colville and Canning Rivers, presumably south or upslope from existing leases, and certain Cook Inlet acreage should be opened under "areawide leasing" principles. Legislative "permission" to open those areas--or any other--to "areawide leasing" could be given in this bill, by an additional uncoded section, or in other legislation.

These are my initial thoughts on this subject. Am I close to what you have in mind?

JBC:glc
95-462.glc

Enclosure

9-LS1341VA
Chenoweth
12/6/95

HOUSE BILL NO.**IN THE LEGISLATURE OF THE STATE OF ALASKA****NINETEENTH LEGISLATURE - SECOND SESSION****BY REPRESENTATIVE ROKEBERG**

Introduced:
Referred:

A BILL**FOR AN ACT ENTITLED**

1 "An Act revising laws relating to oil and gas leasing to authorize a program of
2 areawide leasing."

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

4 * Section 1. AS 38.05.035(a) is amended to read:

5 (a) The director shall

6 (1) have general charge and supervision of the division and may
7 exercise the powers specifically delegated to the director; may employ and fix the
8 compensation of assistants and employees necessary for the operations of the division;
9 and is the certifying officer of the division, with the consent of the commissioner, and
10 may approve vouchers for disbursements of money appropriated to the division;

11 (2) manage, inspect, and control state land and improvements on it
12 belonging to the state and under the jurisdiction of the division;

13 (3) execute laws, rules, regulations, and orders adopted by the
14 commissioner;

1 (4) prescribe application procedures and practices for the sale, lease,
2 or other disposition of available land, resources, property, or interests [INTEREST]
3 in them, including disposal of interests in land under areawide oil and gas leasing
4 authorized under AS 38.05.180(dd) for an area in which area wide leasing has
5 been specifically authorized by the legislature;

6 (5) prescribe fees or service charges, with the consent of the
7 commissioner, for any public service rendered;

8 (6) under the conditions and limitations imposed by law and the
9 commissioner, issue deeds, leases, or other conveyances disposing of available land,
10 resources, property, or [ANY] interests in them;

11 (7) have jurisdiction over state land, except that land acquired by the
12 Alaska World War II Veterans Board and the Agricultural Loan Board or the
13 departments or agencies succeeding to their respective functions through foreclosure
14 or default; to this end, the director possesses the powers and, with the approval of the
15 commissioner, shall perform the duties necessary to protect the state's rights and
16 interest in state land, including the taking of all necessary action to protect and enforce
17 the state's contractual or other property rights;

18 (8) [REPEALED]

19 (9)] maintain such records as the commissioner considers necessary,
20 administer oaths, and do all things incidental to the authority imposed; the following
21 records and files shall be kept confidential upon request of the person supplying the
22 information:

23 (A) the name of the person nominating or applying for the sale,
24 lease, or other disposal of land by competitive bidding;

25 (B) before the announced time of opening, the names of the
26 bidders, and the amounts of the bids;

27 (C) all geological, geophysical, and engineering data supplied,
28 whether or not concerned with the extraction or development of natural
29 resources;

30 (D) except as provided in AS 38.05.036, cost data and financial
31 information submitted in support of applications, bonds, leases, and similar

1 items;

2 (E) applications for rights-of-way or easements;

3 (F) requests for information or applications by public agencies
4 for land that [WHICH] is being considered for use for a public purpose;

5 (9)[(10)] account for the fees, licenses, taxes, or other money received
6 in the administration of this chapter, including the sale or leasing of land, identify their
7 source, and promptly transmit them to the proper fiscal department after crediting them
8 to the proper fund; receipts from land application filing fees and charges for copies of
9 maps and records shall be deposited immediately in the general fund of the state by
10 the director;

11 (10) [(11)] select and employ or obtain at reasonable compensation
12 cadastral, appraisal, or other professional personnel the director considers necessary for
13 the proper operation of the division;

14 (11) [(12)] be the certifying agent of the state to select, accept, and
15 secure by whatever action is necessary in the name of the state, by deed, sale, gift,
16 devise, judgment, operation of law, or other means any land, of whatever nature or
17 interest, available to the state; and be the certifying agent of the state, to select, accept,
18 or secure by whatever action is necessary in the name of the state any land, or title or
19 interest to land available, granted, or subject to being transferred to the state for any
20 purpose [;

21 (13) REPEALED

22 (14) REPEALED].

23 * Sec. 2. AS 38.05.035(e) is amended to read:

24 (e) Upon a written finding that the interests of the state will be best served,
25 the director may, with the consent of the commissioner, approve contracts for the sale,
26 lease, or other disposal of available land, resources, property, or interests in them. In
27 [, AND, IN] addition to the conditions and limitations imposed by law, the director
28 may impose additional conditions or limitations in the contracts as the director
29 determines, with the consent of the commissioner, will best serve the interests of the
30 state. The preparation and issuance of the written finding by the director is subject to
31 the following:

(1) with the consent of the commissioner and subject to the director's discretion, either for a specific proposed disposal of available land, resources, or property, or of an interest in them, or for a disposal under AS 38.05.180(dd) of land, resources, or property, or an interest in them, the director, in the written finding,

(A) shall establish the scope of the administrative review on which the director's determination is based, and the scope of the written finding supporting that determination; the scope of the review and finding may address only reasonably foreseeable, significant effects of the uses proposed to be authorized by the disposal;

(B) may limit the scope of an administrative review and finding for a proposed disposal to

(i) applicable statutes and regulations;

(ii) the facts pertaining to the land, resources, or property, or interest in them, that the director finds are material to the determination and that are known to the director or knowledge of which is made available to the director during the administrative review; and

(iii) issues that, based on the statutes and regulations referred to in (i) of this subparagraph, on the facts as described in (ii) of this subparagraph, and on the nature of the uses sought to be authorized, the director finds are material to the determination of whether the proposed disposal will best serve the interests of the state;

[AND]

(C) may, if the project for which the proposed disposal is sought is a multiphased development, limit the scope of an administrative review and finding for the specific proposed disposal to the applicable statutes and regulations, facts, and issues identified in (B)(i) - (iii) of this paragraph that pertain solely to a discrete phase of the project when

(i) the only uses to be authorized by the specific proposed disposal are part of that discrete phase;

(ii) the department's approval is required before the next phase of the project may proceed; and

(iii) the department describes its reasons for a decision to phase and conditions its approval to ensure that any additional uses or activities proposed for that or any later phase of the project will serve the best interests of the state; and

(D) shall, if the proposed disposal of interests in land occurs under an areawide oil and gas lease authorized under AS 38.05.180(dd) for an area in which areawide leasing has been specifically authorized by the legislature, include within the scope of the administrative review and finding the entirety of the area in which areawide leasing has been specifically authorized by the legislature;

(2) the director shall discuss in the written finding prepared and issued under this subsection the reasons that each of the following was not material to the director's determination that the interests of the state will be best served:

(A) facts pertaining to the land, resources, or property, or an interest in them other than those that the director finds material under (1)(B)(ii) of this subsection; and

(B) issues based on the statutes and regulations referred to in (1)(B)(i) of this subsection and on the facts described in (1)(B)(ii) of this subsection;

(3) a written finding for an oil and gas lease sale under AS 38.05.180 is subject to (g) of this section;

(4) a contract for the sale, lease, or other disposal of available land or an interest in land is not legally binding on the state until the commissioner approves the contract but, if the appraised value is not greater than \$50,000 in the case of the sale of land or an interest in land, or \$5,000 in the case of the annual rental of land or interest in land, the director may execute the contract without the approval of the commissioner;

(5) public notice requirements relating to the sale, lease, or other disposal of available land or an interest in land for oil and gas proposed to be scheduled in the five-year oil and gas leasing program under AS 38.05.180(b) or in an areawide oil and gas leasing program under AS 38.05.180(dd), are as follows:

1 (A) before a public hearing, if held, or in any case not less than
2 180 days before the sale, lease, or other disposal of available land or an interest
3 in land, the director shall make available to the public a preliminary written
4 finding that states the scope of the review established under (1)(A) of this
5 subsection and includes the applicable statutes and regulations, the material
6 facts and issues in accordance with (1)(B) of this subsection, and information
7 required by (g) of this section, upon which the determination that the sale,
8 lease, or other disposal will serve the best interests of the state will be based;
9 the director shall provide opportunity for public comment on the preliminary
10 written finding for a period of not less than 60 days;

11 (B) after the public comment period for the preliminary written
12 finding and not less than 90 days before the sale, lease, or other disposal of
13 available land or an interest in land for oil and gas, the director shall make
14 available to the public a final written finding that states the scope of the review
15 established under (1)(A) of this subsection and includes the applicable statutes
16 and regulations, the material facts and issues in accordance with (1) of this
17 subsection, and information required by (g) of this section, upon which the
18 determination that the sale, lease, or other disposal will serve the best interests
19 of the state is based;

20 (6) before a public hearing, if held, or in any case not less than 21 days
21 before the sale, lease, or other disposal of available land, property, resources, or
22 interests in them other than a sale, lease, or other disposal of available land or an
23 interest in land for oil and gas under (5) of this subsection, the director shall make
24 available to the public a written finding that, in accordance with (1) of this subsection,
25 sets out the material facts and applicable statutes and regulations and any other
26 information required by statute or regulation to be considered upon which the
27 determination that the sale, lease, or other disposal will best serve the interests of the
28 state was based; however, a written finding is not required before the approval of

29 (A) a contract for a negotiated sale authorized under
30 AS 38.05.115;

31 (B) a lease of land for a shore fishery site under AS 38.05.082;

(C) a permit or other authorization revocable by the commissioner;

(D) a mineral claim located under AS 38.05.195;

(E) a mineral lease issued under AS 38.05.205;

(F) a production license issued under AS 38.05.207;

(G) an exempt oil and gas sale under AS 38.05.180(d) of acreage offered in a sale that was held within the previous five years if the sale was subject to a written best interest finding, unless the commissioner determines that new information has become available that justifies a revision of the best interest finding; [OR]

(H) a lease sale under AS 38.05.180(w) of acreage offered in a sale that was held within the previous five years if the sale was subject to a best interest finding, unless the commissioner determines that new information has become available that justifies a revision of the best interest finding; or

(I) an oil or gas lease sale in an area that is part of an areawide lease under AS 38.05.180(dd) within an area in which areawide leasing has been authorized by the legislature if the lease sale was subject to a best interest finding for the area, unless the commissioner determines that new information has become available that justifies a revision of the best interest finding;

(7) the director shall include in

(A) a preliminary written finding, if required, a summary of agency and public comments, if any, obtained as a result of contacts with other agencies concerning a proposed disposal or as a result of informal efforts undertaken by the department to solicit public response to a proposed disposal, and the department's preliminary responses to those comments; and

(B) the final written finding a summary of agency and public comments received and the department's responses to those comments.

* Sec. 3. AS 38.05.180(b) is amended to read:

(b) The commissioner shall biennially prepare and, between the first and the 15th day of the first regular session of each legislature, notify the legislature of the

1 availability of,

2 (1) a five-year proposed oil and gas leasing program consisting of a
3 schedule of proposed lease sales and specifying as precisely as practicable the location
4 of tracts proposed to be offered for oil and gas leasing during the calendar year in
5 which the proposed program is made available to the legislature and the following four
6 calendar years; and

7 (2) a proposed areawide oil and gas leasing program.

8 * Sec. 4. AS 38.05.180 is amended by adding a new subsection to read:

9 (dd) The director, with the approval of the commissioner, shall establish a
10 program of areawide oil and gas leasing to operate with each area as to which the
11 legislature has, by law, authorized areawide oil and gas leasing. Under the authority
12 granted in this subsection,

13 (1) when the commissioner identifies tracts for inclusion in the
14 proposed lease sale, the commissioner shall include at a minimum all of the tracts
15 reasonably believed by the commissioner to cover the entirety of an oil or gas reservoir
16 sought to be developed;

17 (2) the issuance and continuance in effect of a lease, or of any
18 assignment or other transfer of a lease, under this subsection must be conditioned upon
19 compliance with regulations adopted to implement this subsection.

20 * Sec. 5. REVISOR OF STATUTES TO REVISE REFERENCES. Due to the deletion
21 of repealed paragraphs in AS 38.05.035(a) by sec. 1 of this Act, the revisor of statutes shall
22 amend cross-references to the affected paragraphs in AS 38.05.035(a) that appear in the
23 following statutes: AS 38.05.133(e), 38.05.180(j)(6)(B), 38.05.275(c), and AS 41.09.010(d).

9-LS1342A ✓
Chenoweth
11/9/95

HOUSE BILL NO.**IN THE LEGISLATURE OF THE STATE OF ALASKA****NINETEENTH LEGISLATURE - SECOND SESSION****BY REPRESENTATIVE ROKEBERG**

Introduced:

Referred:

A BILL**FOR AN ACT ENTITLED**

1 "An Act relating to 'best-interest findings' for oil and gas leases."

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

3 * **Section 1.** AS 38.05.035(g) is amended to read:

4 (g) Notwithstanding (e)(1)(A) and (B) of this section, when the director
5 prepares a written finding required under (e) of this section for an oil and gas lease
6 sale scheduled under AS 38.05.180, the director shall consider and discuss

7 (1) in a preliminary or final written finding facts that are known to the
8 director at the time of preparation of the finding and that are

9 (A) material to issues that were raised during the period allowed
10 for receipt of public comment, whether or not material to a matter set out in
11 (B) of this paragraph, and within the scope of the administrative review
12 established by the director under (e)(1) of this section; or

13 (B) material to the following matters:

14 (i) property descriptions and locations;

15 (ii) the petroleum potential of the sale area, in general

terms;

(iii) fish and wildlife species and their habitats in the area;

(iv) the current and projected uses in the area, including uses and value of fish and wildlife;

(v) the governmental powers to regulate oil and gas exploration, development, production, and transportation;

(vi) the reasonably foreseeable cumulative effects of oil and gas exploration, development, production, and transportation on the sale area, including effects on subsistence uses, fish and wildlife habitat and populations and their uses, and historic and cultural resources;

(vii) lease stipulations and mitigation measures, including any measures to prevent and mitigate releases of oil and hazardous substances, to be included in the leases, and a discussion of the protections offered by these measures;

(viii) the method or methods most likely to be used to transport oil or gas from the lease sale area, and the advantages, disadvantages, and relative risks of each;

(ix) the reasonably foreseeable fiscal effects of the lease sale and the subsequent activity on the state and affected municipalities and communities, including the explicit and implicit subsidies associated with the lease sale, if any;

(x) the reasonably foreseeable effects of oil and gas exploration, development, production, and transportation on municipalities and communities within or adjacent to the lease sale area; and

(xi) the bidding method or methods adopted by the commissioner under AS 38.05.180; [AND]

(2) in a preliminary or final written finding that is revised as required by (e)(6)(G) or (H) of this section, facts that are known to the director at the time of preparation of the revised finding and that require discussion under

1 (1) of this subsection; however, in making the revised finding, the director shall
2 consider and discuss facts described in (1) of this subsection as to which new
3 information has become available that justifies a revision and need not consider
4 and discuss facts described in (1) of this subsection for which no new information
5 has become available; and

6 (3) the basis for the director's preliminary or final finding, or the
7 director's revised preliminary or final finding, as applicable, that, on balance,
8 leasing the area would be in the state's best interest.



50908

LEGISLATIVE TELECONFERENCE NETWORK SIGN-IN SHEET

Invitation Only
PLEASE PRINT

SPONSOR: Nause Oil & Gas
SUBJECT: Bonding for oil & gas
START/END TIME: 10am DATE: 12-18

	Name/Representing	Address	Zip	Phone No.	Testify	Observe	Bill No.
1.	Betty Cox - Brady & Company	PO Box 107502 Anch 99510		276-5617			
2.	Tom Chapple - ADEC	555 Cordova St Anch 99501		269-7686			
3.	JOE SAUTNER - ADEC	555 Cordova St. Anch. 99501		269-7539			
4.	Rob Mintz - Dept of Law	1031 W 4th Ave, Ste 200 Anch	99501	269-5255	(respond to questions)		
5.	Paul Craig / Trading Bay	2900 Kenif Pkwy #610 99504		563-5686	x		
6.	Dave Johnson / AOGCC	306 Percussion Dr Anchorage	99501	279-1422	(respond to questions)		
7.	Dave Laffi	4900 Sportsman Dr. 99502		248-7188	X		
8.	Pat Foley	Box 100360 Anch AK	99516	265-6213			
9.	Brad Penn	PO Box 196168 Anchorage, AK	99519	564-6428		X	
10.	ARDIE GRAY - AOGA	121 W FIREWHEEL STE 207 ANCH	99503	272-7424		X	
11.	PATRICK COUGHLIN	1031 W 4th Ave, Suite 200, ANCH	99501	269-5255			
12.	Katelyn Ohmer	480 W Tudor, Anch AK	99503	561-8050		X	
13.							
14.							
15.							