

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

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The problem created by the large minimum size of the North Slope project is further exacerbated by the number of buyers that would be required to consume the proposed project volume. Most likely the need to find buyers for this new large volume all at once will require sales to several customers in more than one country, and the sale to any one customer is likely to be dependent on sales to all other customers. This could make marketing the ANS gas a complicated endeavor.

4. The Role of Gas in Prudhoe Bay Liquid Production.

Currently the highest and best use of the gas in the Prudhoe Bay reservoir is to facilitate the production of liquids. Gas reinjected into the reservoir increases liquid recovery as a result of several different recovery mechanisms. When does it make sense to sacrifice liquid recovery for gas production? The answer is: when substituting gas production for liquid production results in a more valuable stream of total outputs from the reservoir. Today the highest value is achieved by maximizing liquid production from the North Slope because the liquid streams are so much more valuable than the likely flow of gas. As liquid production rates decline, however, a time may come when the potential gas stream will become more valuable than that of the liquids sacrificed by sending the gas to market. The volume of liquids sacrificed declines every year the project is delayed.

The liquid recovery mechanisms at Prudhoe Bay all depend directly or indirectly on reservoir pressure. Production is facilitated by higher pressure, which pushes the oil out of the rock. The pressure in the reservoir depends mainly on the amount of oil, gas and water in the reservoir. Because of its compressibility, reinjection of produced gas is the primary mechanism used to

maintain pressure in the Prudhoe Bay reservoir. Injection of sea water and produced water are also major elements in the Prudhoe Bay reservoir pressure maintenance program.

A Major Gas Sale (MGS) of Prudhoe Bay gas would permanently remove the gas from the Prudhoe Bay reservoir and consequently accelerate the decline in reservoir pressure. The pressure in the Prudhoe Bay reservoir is currently declining at 30 pounds per square inch (PSI) per year. When production began in 1977, the Prudhoe Bay reservoir pressure was 4,200 PSI; today it is 3,400 PSI. The producers estimate that an MGS would triple the rate of annual decline to 90 PSI unless new steps were taken to mitigate some of the loss. There is no disagreement that in the short run (next 8-10 years) accelerated reservoir pressure decline would result in less ultimate oil production. There is some disagreement as to the timing and total volume loss associated with the proposed gas pipeline project, and on the manner in which the loss might be mitigated. However, there appears to be no guaranteed, low cost way to mitigate these losses.¹⁰

Thus the optimal date for an MGS depends on the expected performance of the Prudhoe Bay reservoir as well as predicted oil and gas prices. The longer the expected benefits from gas

¹⁰ Where maintaining high reservoir pressure is necessary to maximize liquid recovery, in some locations around the world the natural gas may be valuable enough to justify marketing it and replacing it in the reservoir with another gas - usually nitrogen cryogenically recovered from the atmosphere. The producers at Prudhoe Bay have considered this option, but the projected wellhead value of Prudhoe Bay gas has always been too low to justify it. Similarly, the Prudhoe Bay producers have considered attempting to mitigate pressure losses through expanded waterflood; they have concluded that would be destructive to gravity drainage in other parts of the reservoir and to oil well hydraulic performance. Finally, the Prudhoe Bay producers have considered injecting water into the apex of the gas cap (as opposed to the oil rim); this step, they believe, could eliminate much of the liquid recovery achieved by the vaporization of residual liquids in the gas cap that occurs with gas cycling.

pressure maintenance and gas cycling, the later the optimal date for commencing an MGS. However, very late in the life of the field, losses in liquid production as a result of an MGS become quite small relative to the value of a gas sale. In addition, the economies of scale realized by producing and selling both oil and gas from the same facilities are such that an MGS would probably extend the time during which oil production would continue to be economic. To the extent an MGS would extend field life, liquid losses would be negated. Likewise, there could be some accelerated oil recovery benefits realized due to increased gas handling capacity resulting from an MGS after 2015.¹¹

The producers now believe that 2005 would be the earliest appropriate time to possibly begin deliveries pursuant to an MGS. They contend that 2010 is the "most likely" time they would commence deliveries under an MGS. The producers have selected the year 2005 as the earliest appropriate time for three reasons:

- The liquid loss after 2005 from diverting gas for commercialization may be de minimis.
- The producers believe 2005 will be a good time to enter the markets (see section on demand above).

¹¹ As the field matures more and more gas is produced with each barrel of oil. Currently approximately 7.5 billion cubic feet of gas are produced each day with the oil at Prudhoe Bay. Oil production capacity is constrained by the ability to process and reinject this large volume of associated gas. Depending on the North Slope equipment scheme ultimately installed, some gas handling capacity is freed up as some gas is diverted for sale. Increasing the gas handling capacity at Prudhoe Bay would certainly result in acceleration of oil recovery, but probably not in significant additional oil recovery. Gas handling capacity probably cannot increase, however, until the waterflood/EOR project ends (around 2015), because of the bottleneck caused by the limited gas dehydration capacity of the flow stations/gathering centers.

- The intra-field compensatory agreements between the oil rim and gas cap owners will mostly be completed then.¹²

Regarding the liquid losses, the producers now estimate that an MGS in 2005 would result in a loss of 400 million barrels of oil over the remaining life of the Prudhoe Bay field. They estimate a loss of 100 million barrels of oil for a 2010 sale. The significance of those losses will depend on the relative prices of oil and gas as well as actual operation and development decisions made over the next ten years. For instance, if we assume the wellhead values of Prudhoe Bay oil currently forecast by the Department of Revenue, then the gas must be worth at least 40 cents per mcf at

¹² The Prudhoe Bay field is unitized with two participating areas: the oil rim and the gas cap. BP owns a relatively higher percentage of the oil rim (51%), and Arco and Exxon own relatively higher percentages of the gas cap (42% each). The gas cap currently has 70% of the gas resources and the oil rim 30%. Thus BP still owns 25% of the overall gas reserves, and has no apparent motive for being disinterested in commercializing the Prudhoe Bay gas absent negative impacts on oil production. Pursuant to an order from the Alaska Oil and Gas Conservation Commission, the working interest owners are currently attempting to unitize the two properties.

In 2005 the fuel gas supply option, whereby the oil rim owners are obligated to secure a certain volume of gas from the gas cap owners to fuel field operations, lapses.

Also, major gas sale delay credits cease in 1997. These are reimbursements of payments of the oil rim owners to the gas cap owners for early investments made by the gas cap owners in anticipation of an early gas sale. The oil rim receives some of their already-paid reimbursements back if there is an MGS before 2005.

In addition, through another agreement, in 2005 the gas cap owners will beg to supply half the gas needed to make miscible injectant for enhanced oil recovery operations. Currently the oil rim owners supply all of the gas. This will release oil rim gas for sale.

There are other incentives in the unit operating agreements for the oil rim owners to support an MGS. Upon an MGS, the gas cap owners will pick up significantly higher proportions of the operating costs of the field. Further, once an MGS occurs the oil rim owners get allocated proportionally more liquids.

the wellhead to offset the value of the barrels lost as a consequence of a gas sale commencing in 2005. To offset the loss of barrels for a gas sale commencing in 2010, the gas wellhead value must only be 15 cents/mcf. The likely level of gas prices is discussed more fully above. These "loss" estimates assume a five year ramp-up to 2 bcf of gas per day sold from Prudhoe Bay. Appendix C describes the derivation of these loss projections.

5. **Point Thomson - A Potential Supply Source Prior to Prudhoe Bay Gas Availability?**

Phillips Petroleum has recently suggested the use of gas from the Point Thomson field to jump start the proposed ANS gas project. The Point Thomson reservoir, a large gas and gas condensate reservoir which overlies a very thin oil rim, is located 60 miles east of Prudhoe Bay. The Department of Natural Resources estimates the reservoir contains 3 tcf of recoverable gas reserves; some producers have estimated the reservoir contains 5 tcf. The reservoir is included in the Exxon-operated Point Thomson Unit.

Phillips, one of the Point Thomson working interest owners - which has interests with co-lessees Mobil and Chevron (together these companies are often referred to as MPC with respect to their jointly leased North Slope properties) - is willing to commit its gas now to the YPC project. Together MPC owns the leases which cover 47% of the surface acreage included in the unit and claim to have a higher percentage of the recoverable reserves in the unit. Phillips believes it may be able to supply up to 1 bcf per day of natural gas from this reservoir for up to five years. If

supplying this amount was indeed feasible, early Point Thomson production could assist in making it possible to commence a North Slope gas project before significant volumes of gas are required from the Prudhoe Bay reservoir. Early gas sales from Point Thomson could allow a gradual phase in of gas sales from Prudhoe Bay.

There are many technical questions that would have to be addressed with respect to this Point Thomson proposal. The Point Thomson reservoir is a very high pressure retrograde condensate reservoir; that means liquids drop out of the gas recovered from the reservoir when the pressure of the gas drops. Under the Phillips proposal would the gas be kept at high pressure and moved to Prudhoe Bay for liquid recovery? Can gas production at the volumes Phillips proposes occur without dropping reservoir pressure to the point where there are significant volumes of liquid lost in the reservoir? Since the Point Thomson reservoir pressure is so high (almost right at 10,000 PSI), doesn't it make sense to produce the reservoir until the pressure drops to the 4,000 - 5,000 PSI range before reinjection and cycling commence to avoid the very high reinjection costs that a 10,000 PSI reservoir would require? If the answer to that question is "Yes," doesn't that suggest that the Phillips proposal may have merit in promoting the development of the Point Thomson resource?

The cost of bringing Point Thomson reserves to the Prudhoe Bay area would, of course add to the cost of the pipeline portion of the project.

III. OTHER CONSIDERATIONS.

1. What's in it for the State.

On the revenue side, under the applicable fiscal regime the State will receive severance taxes, royalties and property taxes from the gas project. The property tax will be the most significant. With \$11 billion of assessed property (which excludes the ships), the 20 mill Oil and Gas Property Tax will yield \$220 million per year initially; the tax revenue from this tax will decline with the depreciation of the property. Half of the revenue from this tax will go to cities and boroughs. This tax will affect the economics of the project two ways. First, because it applies during the construction period, it is a large additional up-front cost imposed on the project; second, once the project is operating, the annual property tax bill will add 30 cents per mcf to the operating costs of the project on an equivalent amortized basis.¹³

If the netback from the Far East yielded a 50 cent/mcf wellhead value, taxes and royalties would total \$60 million annually. Based on current cost projections, a 50 cent wellhead value would be achieved only if LNG prices were \$5.50/mmbtu in the Far East (and oil prices were \$27.50/bbl - see discussion in Section II(1) above). Under the current applicable state corporate income tax statute, the state would receive about \$30 million per year in corporate income taxes from the project. Thus, if world energy prices increase by 60 percent, the state could expect about \$190 million per year in taxes and royalties from the project during the early years of operation. That amount would, of course, decline as the value of the gas pipeline depreciated.

¹³ The \$5/mmbtu LNG cost discussed on page 10 in Section II(1) includes the amount of this tax.

Construction of a pipeline to transport gas from the North Slope to Valdez would create 10,000 construction jobs and 600 permanent operational jobs. A pipeline following the TAPS corridor would also make natural gas available to Fairbanks, Valdez and other smaller communities along the route.

An MGS would enhance the economics of other gas deposits on the North Slope.

In addition, as discussed above, the commercialization of gas late in the life of the Prudhoe Bay reservoir would probably enhance oil production economics as well.

2. The Role of Yukon Pacific.

YPC has been active in promoting an ANS LNG project that would use the TAPS route to Valdez. YPC is a subsidiary of CSX Corporation, a conglomerate with holdings concentrated in transportation. CSX owns one of the nation's largest railroads, and it owns Sealand. As a consequence of other business involvements, CSX has had significant experience in marine transportation and in certain aspects of the gas business.

YPC has spent large amounts of time and money obtaining several of the major permits necessary to transport and market gas. These include:

- Presidential finding for the project.
- Project-wide environmental impact statement.

- Federal right-of-way
- State right-of-way
- Department of Energy authorization for export of gas.
- Final environmental impact statement for a liquefaction plant at Anderson Bay near Valdez.
- FERC order granting authorization for LNG facility siting.

Although the degree to which some of these permits may be exclusive is questionable, there is considerable time, expense, and expertise invested in their procurement.

The North Slope producers clearly have the right to utilize the Prudhoe Bay gas for oil production as long as they are not wasting the gas. They also have the right to market the gas. If Prudhoe Bay gas commercialization yielded a higher net present value than utilizing the gas in the field to maximize oil production, the state might be able to take action to compel the producers to market the gas. In the absence of some sort of successful state action to compel Prudhoe Bay gas sales, YPC must depend solely on the oil rim and gas cap owners to obtain Prudhoe Bay gas.

There are disagreements among YPC and the producers. YPC has argued that based on the public statements made by the producers, there is no reason the gas should not be currently available for sale. YPC has also argued that: (1) the Prudhoe Bay producers will not sell the gas because of intra-owner conflict in the field resulting from the disparate oil/gas ownership; (2) specific companies are improperly advancing their own interests either in the field or in other places in the

world with a decision not to sell even though, according to YPC, selling would maximize the overall benefits from the Prudhoe Bay Reservoir; and (3) the State should take action to force the Prudhoe Bay producers to enter into an MGS. We believe there are sound engineering and economic reasons behind the current plans for short term and mid term gas use at Prudhoe Bay

IV. WHAT SPECIFIC ACTIONS HAVE THE VARIOUS PARTIES URGED THE STATE TO CONSIDER?

Following are some of the ideas interested parties, including YPC and the producers, have urged the state to study:

1. Taking action to force the Prudhoe Bay producers to sell their Prudhoe Bay gas;
2. Using the state's royalty-in-kind share of Prudhoe Bay gas to promote the proposed project;
3. Marketing the state's royalty-in-kind share of Prudhoe Bay gas along with the producers to promote the project;
4. Agreeing to commit the state's royalty-in-kind share of Prudhoe Bay gas to the project at a fixed (and possibly discounted) price;
5. Altering the 20 mill Oil and Gas Property Tax so it does not impose another large front-end cost on the project; and
6. Altering the state's basic fiscal arrangements so that the state takes an equity interest in the entire project up stream from the LNG tankers, and, in exchange, agrees to forego royalties, severance tax and the 20 mill Oil and Gas Property Tax.

These questions should all be addressed in conjunction with the implementation of the 14 recommendations set forth on pages 4, 5 and 6 of this briefing paper.

APPENDIX A

Alaska North Slope Gas Transportation System Feasibility

The Relationship Between Required Rate of Return and Far East Market LNG Prices

At today's energy prices and projected construction costs, the proposed North Slope gas project is economically feasible if and only if the project's would-be investors are willing to accept a fairly low rate of return for the project. Consequently, it is unlikely these firms will be willing to provide the necessary financing to construct the project unless they are convinced of one or more of the following:

1. The project is, in fact, a very low risk project;
2. The price of LNG in the Far East is likely to increase significantly in the next few years thereby providing a much higher return for the proposed project than would be available at current prices; or
3. The project construction costs will be significantly lower than the current estimate of \$15 billion.

An investor's willingness to invest depends on the balance of anticipated risk and reward from the investment. Citizens are willing to invest in passbook savings accounts with their relatively low returns (approximately 4.5% today) in part because the U.S. government insures that depositors will get their money back virtually any time they want it. On the other hand, high-risk investments command higher returns to compensate investors for the risk. For example some

computer venture start-ups are currently yielding returns near 25% to their investors. For large projects, a firm's willingness to invest will depend on the perceived risk and reward of the project compared to other opportunities for investing available funds. A firm will invest in projects with the highest anticipated return balanced against the anticipated risk. Projects compete for financing based on their perceived risk and rates of return.

For example, to assure a 7% nominal rate of return (1.5% after-tax real), the proposed North Slope LNG project would need a \$3.65/mmbtu price floor in the Far East and a zero wellhead netback (the current Far East LNG price is \$3.50/mmbtu). But, one can get this same return by making a riskless investment in the government bond market.

We do not know precisely the risk would-be investors will perceive in the proposed North Slope gas transportation project. Will the project face a significant marketing risk? It is highly likely that if the project is constructed there will be little risk that the project will not have guaranteed customers. The contracts for LNG sales in the Far East would almost certainly be in place prior to construction commencement. How about the risk of very low energy prices? Far East LNG contracts are almost universally pegged to the price of oil and other energy supplies, but if oil prices fall below a certain level, the gas prices may be subject to renegotiation. To insure a 2% after-tax real rate of return, this project needs a \$3.90/mmbtu price floor in the Far East. What happens if the project costs \$18 billion rather than \$15 billion? Then the very low return realized at today's energy prices would become negative.

Will the perceived risk of this proposed project require a return equal to or greater than: (1) a thirty year treasury bond; (2) a AA corporate bond; (3) a BBB corporate bond; (4) the return equity investors currently receive for investing their funds in developed, stable utility companies; or (5) the return earned by investors in the Trans Alaska Pipeline System (TAPS) as a consequence of the tariff settlement agreement?

The charts that follow use "after-tax real" rates of return. It may be helpful to explain briefly the relationship between "after-tax real" and "nominal" rates of return. After-tax real rates of return are the returns realized after making an allowance for inflation and income taxes.

The after-tax real rate of return is the difference derived by subtracting the inflation rate from the product of the nominal rate of return multiplied by the difference obtained by subtracting the tax rate from one. It may be easier to understand this equation by expressing it algebraically as follows:

$$\text{After-Tax Real Rate of Return} = [\text{Nominal Rate of Return} * (1 - \text{Tax Rate})] - \text{Inflation Rate}$$

To work through an example, take the applicable 30 year U S Government Bond rate, which currently provides a return of 6%. Further, assume an effective combined corporate income tax rate of 38.0% (35% federal and 4% composite state)¹ and an inflation rate of 3%.

¹ Since the state tax is deductible for federal taxes the combined rate is 38%.

$$\begin{aligned}
 \text{After-Tax Real Rate of Return} &= [\text{Nominal Rate of Return} * (1 - \text{Tax Rate})] - \text{Inflation Rate} \\
 &= [0.06 * (1 - 0.38)] - 0.03 \\
 &= 0.0072, \text{ or } 0.72\%
 \end{aligned}$$

The following table compares the nominal returns in today's marketplace with the corresponding after-tax real returns. Again the basic assumptions are: a 38% effective combined corporate income tax rate and a 3% inflation rate.

NOMINAL AND REAL RATES OF RETURN		
	Nominal Rate of Return	Real After Tax Rate of Return
30 Year Treasury	6.0%	0.72%
AA Corporate Bond	6.8%	1.22%
BBB Corporate Bond	7.4%	1.59%
Rate of Return Received by Equity Investors in Developed, Stable Utility Projects	10.5%	3.51%
Rate of Return Selected for Illustrative Purposes for the Proposed ANS Gas Transportation Project	11.4%	4.07%
Rate of Return Permitted TAPS Owners under TAPS Tariff Settlement	15.0%	6.40%

On the basis of this information, is a 4% after-tax real rate of return required to attract investors to the proposed ANS gas transportation project? Is it too high? Is it too low? The following

analysis uses that rate of return for illustrative purposes. There are many good arguments that this 4% after-tax real rate of return is in the neighborhood of the return investors would require to invest in the proposed North Slope LNG project. One could certainly make the case that the proposed Alaska to Far East LNG project would be less risky than TAPS. There is virtually no risk that the gas cannot be produced from the reservoir. There would be a set contract in place guaranteeing a price. Construction of the TAPS project proved that such a large Arctic project can be done. The builders of the proposed LNG project can profit from the TAPS construction experience.

Figure 1 below shows the price LNG must receive in the Far East to yield various after-tax real rates of return on the proposed project.

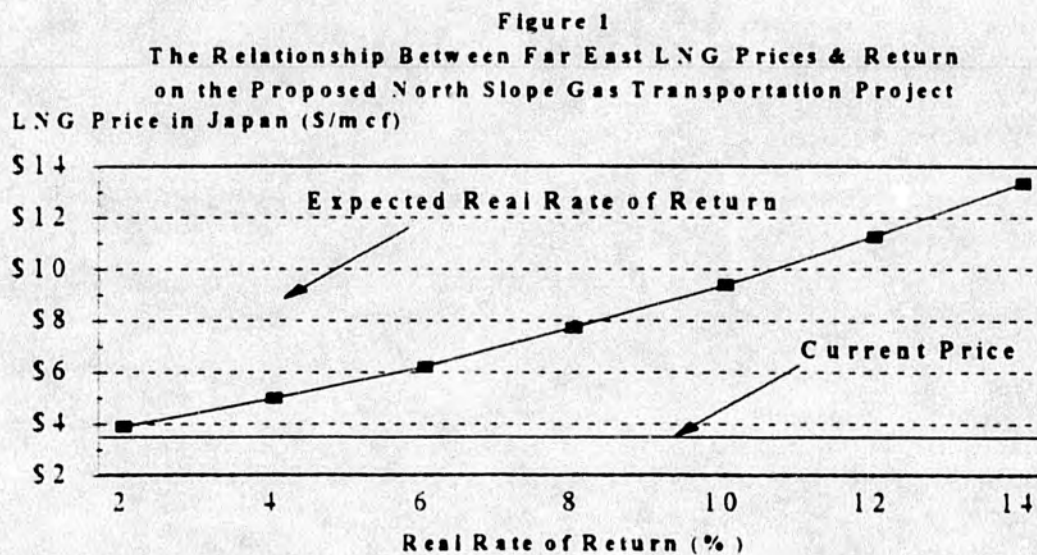


Figure 1² shows that to obtain a 2% after-tax real rate of return on the proposed \$15 billion transportation project with a twenty-five year project life, the price of LNG in the Far East would have to be \$3.90/mmbtu; at this price the project would yield a zero wellhead value. The current price in Japan is \$3.50/mmbtu. This equates to an after-tax real rate of return on the project with a zero wellhead value slightly under 2%. Using the same assumptions, Figure 1 shows that a 4% after-tax real rate of return with a zero wellhead value requires a \$5.00/mmbtu sales price in the Far East.

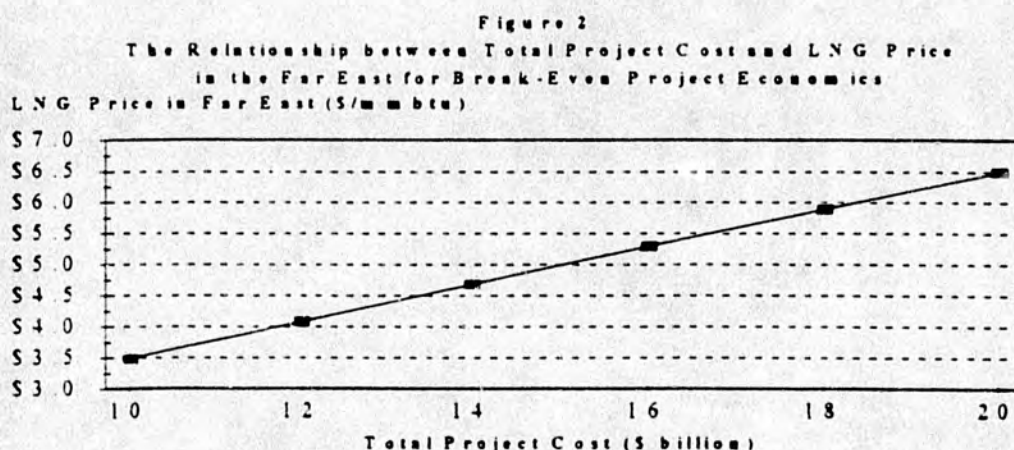
In addition to using equity to finance part of the project, the investors will probably make arrangements to issue debt to finance a portion as well. For many reasons, the interest rates on the debt issued to construct the proposed LNG project will probably be lower than the return required to attract equity capital.

For the analysis in this briefing paper, we have assumed the project would be financed by 75% debt and 25% equity. The debt/equity ratio could vary widely. We have assumed a nominal rate of return on the equity portion of the investment of 12.9%, for the debt we have assumed a nominal rate of return 2% below the equity rate. These assumed rates of return may not accurately reflect those that would be obtained for financing the project. We believe, however, that a combined real after-tax rate of return of about 4% for the project is the lowest return investors would accept.

² These figures include a \$0.50/mcf operating cost and a \$0.30/mcf 20 mill oil and gas property tax payment.

At a 4% real after-tax rate of return on the project, a price of \$5.00/mmbtu in the Far East would be required to yield a zero wellhead value. If the project were 100% debt financed, the required Far East price would be \$4.50/mmbtu. If the project were 100% equity financed, the required Far East price would be \$6.40/mmbtu.

Figure 2 depicts the break-even gas price required in the Far East at different project construction costs. For this comparison the assumed financing arrangements are: (1) 75% debt and 25% equity; (2) the equity portion requires a 5% real after-tax rate of return; (3) the debt portion of the project is financed at a rate 2% less than the nominal equity return; and (4) the inflation rate over the life of the project is 3%. At the current project cost estimate of \$15 billion, the required destination price in the Far East is \$5.00/mmbtu. Figure 2 shows that it would take a one-third reduction in project construction costs, to \$10 billion, for the current price in the Far East, \$3.50/mmbtu, to yield a zero wellhead value on the North Slope.



APPENDIX B

Technical Description of Gas Line Rate of Return Model

The gasline rate of return (ROR) model computes a levelized per mcf amount that computes break-even transportation costs for the entire system, including the tankers, at a specified rate of return. The model uses a cost of service methodology. The levelized cost is the total discounted cost divided by the total discounted volume. There are six cost components: depreciation, operating costs, property tax, income tax, interest, minimum cents per mcf severance tax¹, and after tax margin (profit or the return on base equity investment).

The after-tax margin is the product of the nominal rate of return and the undepreciated equity capital. The income tax allowance is the product of the tax gross-up factor and the after tax margin. The tax gross-up factor is that number which when multiplied by the after tax margin yields the state and federal corporate income tax amounts given the cost of service for the given year.²

In this model we assumed no inflation for the system components and 3% for the economy as a whole. We have also assumed 75% debt and 25% equity, with the cost of debt at two percentage

¹ The minimum cents per mcf severance tax is 6.4 cents. We have assumed an economic limit factor of 0.8.

² Given a state corporate income tax rate of 9.4% and a federal corporate income tax rate of 35%, the tax gross-up factor is:

$$(.094 + (.35 \times (1 - .094))) / (1 - (.094 + (.35 \times (1 - .094)))) = 0.6981$$

points below the nominal rate of return.

Other key assumptions include:

- \$15 billion in capital costs
- \$11 billion in non-ship capital subject to the property tax
- 2 million mcf per day for 25 years
- 5 year ramp-up
- \$0.50/mcf operating costs
- 1.1 mmbtu to mcf ratio

The model is shown on the following table.

APPENDIX C

Technical Explanation for Estimating the Value of Lost Oil

Currently the highest and best use of gas at Prudhoe Bay is to facilitate oil production. The producers have estimated that an MGS in 2005 would result in a loss of 400 million barrels of oil over the remaining life of Prudhoe Bay, and a 2010 sale would result in a 100 million barrel loss.

The significance of those losses depend on the relative values of oil and gas. Because of the time value of money these values are dependent on the time profile of the losses. The projected time profile of these losses is shown below.

The loss in oil reserves is a function of cumulative gas removed from the reservoir over time. A uniform series time rating function relates the loss of an mcf of gas to both an immediate loss of oil and a loss of oil through time.

We estimated time series of reserves losses for both 2005 and 2010 sales. These losses were multiplied by the respective predicted oil price for the subject year and discounted at 10%. The total discounted losses were divided by the total discounted volume of gas. This represents the wellhead price of gas that would make the producers indifferent to the reserve losses.

For a 2005 sale the gas price is \$0.40/mcf, and for 2010 the price is \$0.15/mcf. The derivation of these amounts is shown on the following tables.

Value of Lost Oil - 2005 Sale

Year	Gas (bcf/y)	Disc Factor	Disc Gas	Oil Price (\$/bbl)	Oil (bbls)	Disc Oil Loss
2005	146	0.953	139	16.61	1	16
2006	292	0.867	253	17.03	2	30
2007	438	0.788	345	17.43	3	41
2008	584	0.716	418	17.91	4	51
2009	730	0.651	475	18.75	6	73
2010	730	0.592	432	19.34	7	80
2011	730	0.538	393	19.81	8	85
2012	730	0.489	357	20.59	9	91
2013	730	0.445	325	21.15	10	94
2014	730	0.404	295	21.83	12	106
2015	730	0.368	268	22.42	13	107
2016	730	0.334	244	23.03	14	108
2017	730	0.304	222	23.65	15	108
2018	730	0.276	202	24.29	17	114
2019	730	0.251	183	24.94	18	113
2020	730	0.228	167	25.62	19	111
2021	730	0.208	151	26.31	20	109
2022	730	0.189	138	27.02	21	107
2023	730	0.171	125	27.75	23	109
2024	730	0.156	114	28.50	24	107
2025	730	0.142	103	29.27	25	104
2026	730	0.129	94	30.06	26	101
2027	730	0.117	86	30.88	28	101
2028	730	0.106	78	31.71	29	98
2029	730	0.097	71	32.57	30	95
			5679		384	2258
					value	(0.40)

Value of Lost Oil - 2010 Sale

Year	Gas (bcf/v)	Disc Factor	Disc Gas	Oil Price (\$/bbl)	Oil (bbls)	Disc Oil Loss
2010	146	0.953	139	19.34	0	0
2011	292	0.867	253	19.81	1	17
2012	438	0.788	345	20.59	1	16
2013	584	0.716	418	21.15	2	30
2014	730	0.651	475	21.83	2	28
2015	730	0.592	432	22.42	3	40
2016	730	0.538	393	23.03	4	50
2017	730	0.489	357	23.65	4	46
2018	730	0.445	325	24.29	5	54
2019	730	0.404	295	24.94	5	50
2020	730	0.368	268	25.62	6	57
2021	730	0.334	244	26.31	6	53
2022	730	0.304	222	27.02	7	57
2023	730	0.276	202	27.75	7	54
2024	730	0.251	183	28.50	8	57
2025	730	0.228	167	29.27	8	53
2026	730	0.208	151	30.06	9	56
2027	730	0.189	138	30.88	9	52
2028	730	0.171	125	31.71	10	54
2029	730	0.156	114	32.57	11	56
2030	730	0.142	103	0.00	0	0
2031	730	0.129	94	0.00	0	0
2032	730	0.117	86	0.00	0	0
2033	730	0.106	78	0.00	0	0
2034	730	0.097	71	0.00	0	0
			5679		108	882
					value	0.16

YUKON PACIFIC CORPORATION

Presentation to the House Oil and Gas Committee and the House Resources Committee
February 1, 1996

TAGS—"What's in it for the State"

We would like to start with one simple message. The "value" of TAGS to the State of Alaska is positive and any delay to bringing the gas line to fruition erodes the "value" of the project. Whatever value you choose to assign to the project, a five year delay reduces the present value of those future cashflows by 38%¹, or if the project starting today is worth \$1.00, delaying those cashflows 5 years reduces the project's value to 62¢. So if you leave with nothing else today, please understand that sooner is better than later and delay is costing the State of Alaska.

We do not intend to schedule out the various revenue streams accruing to the State of Alaska as a result of TAGS, but conceptually, let's identify some potential sources.

Values from the Well-head

- Royalty
- Severance
- Incremental Corporate Income Tax

Values from the Transportation System

- Property Taxes
- Corporate Income Taxes

Other Potential benefits

- Personal Income Tax—Construction/Operation

- Increased and/or accelerated PBU oil production through additional gas handling capacity and extending field life.

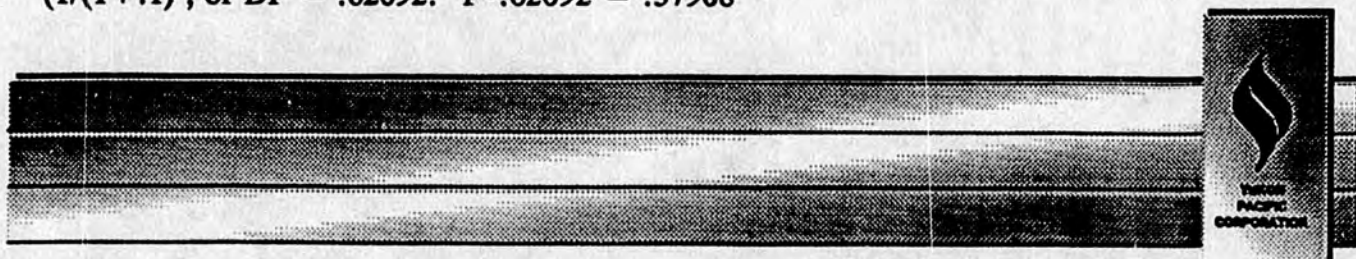
- Increased exploration activity for oil & gas on the North Slope.

- New development opportunities: Point Thomson Unit

- Gas supplied along the pipeline corridor

- Power generation from waste heat at the LNG facility.

¹Discount factor calculated as $1/(1+i)^N$, where $i = 10\%$ and $N = 5$ years, then $DF = 1/(1+.1)^5$, or $DF = .62092$. $1 - .62092 = .37908$



Now, let's make sure everyone has a firm picture of where we are and what we are asking from the State of Alaska.

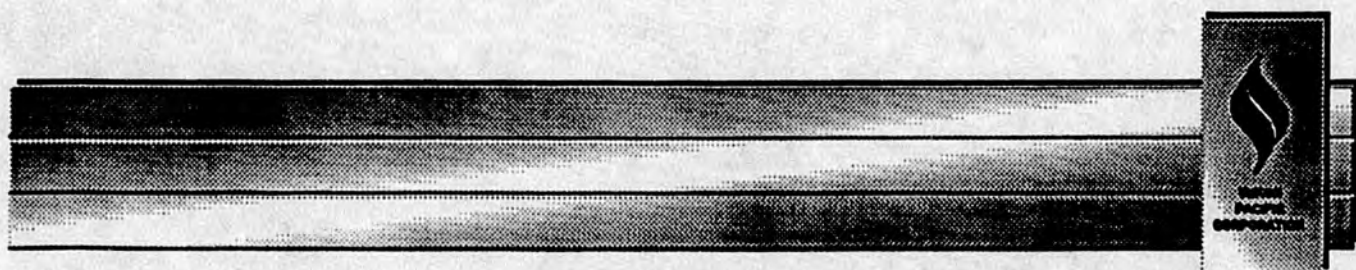
During the previous hearings, testimony was provided which seemed to imply that given certain assumptions, TAGS economics are marginal. Well that's a "glass is half empty approach". We are here to tell you that the "glass is half full". And better yet, we believe that the glass can be filled to the top.

- The market is there and will invest.
- Any potential oil loss will be more than off-set by the benefits of TAGS and the PBU's reluctance to let gas come off the slope before 2005 can be addressed using Point Thomson.
- WE NEED ACCESS TO THE GAS to secure our place in this market window.

The State of Alaska owns the gas in the ground. The producers have an obligation to produce that gas. The producers are saying that ANS gas commercialization is not economic. They don't get to decide. They can choose whether or not to invest in the transportation system but they can not decide whether or not the gas should be "produced". This should be in the hands of the State of Alaska.

The producers (and the State) for that matter have no risk. If YPC is successful in securing market commitments and proceeding with TAGS, every one wins. The oil companies earn a netback, the State of Alaska gets the various benefits of TAGS and YPC, and its partners and the State of Alaska will have a world class LNG project which will be a cornerstone of Alaska's economy for 50 years.

If we are wrong, the fall back position is that proposed by the oil companies (i.e., sometime around 2010). No one will have lost any ground. But remember, time is money and we are all wasting both.



TRANS-ALASKA GAS PIPELINE:

PARTNERS AND ISSUES

Provided by Yukon Pacific Corporation

PRIMARY PARTNERS:

- 1) **The people of Alaska** - this partner owns the gas reserves on State lands on the North Slope.
- 2) **The major oil companies** - Exxon, BP and ARCO in Prudhoe Bay and Phillips Petroleum, Mobil, Chevron and Exxon in Point Thomson. These companies have leased the rights and committed to produce the State's oil and gas.
- 3) **Yukon Pacific Corporation** - this partner has secured the permits for a trans-Alaska gas line in the congressionally designated pipeline corridor. This permitting process took ten years. They have also obtained an export license for the gas.
- 4) **Walter J. and Ermalee Hickel Foundation** - while Wally Hickel was Governor, he signed over his ownership interests in Yukon Pacific stock to a charitable foundation. This foundation is governed by a board which makes all decisions on allocation of the funds earned from 10% of the profits of Yukon Pacific. The board is chaired by Archbishop Hurley of Anchorage and the allocations are restricted to Alaskan charitable organizations. As state and federal expenditures for social programs are reduced, this foundation could identify and fill funding gaps.
- 5) **The State Legislature and the Governor** - these partners control the State's royalty gas, 12 1/2% of the produced gas which they could commit to this project. The sale of this royalty gas and state taxes are of great interest to State government for the purpose of balancing the state budget.
- 6) **Alaska Native corporations** - these corporations own land near Prudhoe Bay and near the gas pipeline corridor which could contain significant gas reserves. The production of these reserves could be facilitated by construction of the Trans Alaska gas pipeline.

SECONDARY PARTNERS:

- 1) **Alaskan workers** - this project would provide significant employment opportunities to Alaskan workers, estimated at 10,000 workers for initial construction and 600 full time workers during long term operations. Pipeline and facility maintenance would create further jobs as we have seen with the oil pipeline.
- 2) **Alaskan service companies** - this project would provide significant contract opportunities for oilfield, transportation and other associated companies.
- 3) **Alaskan communities** - these partners would benefit from local tax revenues, access to use of the gas along the pipeline corridor. AML has passed a resolution in support, (attached) as have other Alaskan local governments. Waste heat from the liquefaction plant would produce 250 to 300 megawatts of electricity which could be fed through interties to Alaskan communities, reducing their electrical rates.
- 4) **America** - This project would provide significant benefits to American workers in equipment manufacturing, transportation, etc. The export of Alaskan gas to Asian markets would also reduce our trade deficit with these companies.

IS THIS PROJECT COMPETITIVE?

The attached chart compares the cost of an Alaskan gas export project and estimated reserves with other projects which could supply gas to the Asian market. This clearly shows that this project is competitive. While we have the expense of building a pipeline, these other projects have significant development costs in production facilities which already exist at Prudhoe Bay.

This project will require a minimum market commitment of 14 million tons of gas per year to be economically feasible. However, the capacity of the system will be 28 million tons per year which could be produced if additional markets are identified. These additional markets could include facilities to refine value added natural gas products such as petrochemicals in Alaska. Any throughput of over 14 million tons per year further improves the economics of this project.

TIMING:

There exists a window of opportunity to market Alaskan gas in the Asian market to meet their demand requirements opening in 2003 to 2004. If these countries cannot obtain commitments for Alaskan gas, they will be forced to commit marketing agreements and financing to other projects even if they are more expensive. If this occurs, the next opportunity to sell Alaskan gas could be as far out as 2025 to 2030 if ever.

If this project is moved forward now, it would also provide substantial state revenues at a time when the Long Range Fiscal Planning Commission has projected that our reserves will be drawn down and personal and other taxes will have to be considered.

WHAT NEEDS TO HAPPEN TO MOVE THIS PROJECT FORWARD?

- 1) The major producers and Yukon Pacific need to negotiate an agreement to market Alaska's natural gas linked to the pipeline construction schedule. Yukon Pacific has offered and continues to offer to negotiate with the major producers and the state on pipeline ownership, profit sharing and all other issues.
- 2) Final engineering needs to be completed to identify methods for minimizing the cost of pipeline construction.
- 3) Financing needs to be identified. Financing from Asian market sources at lower interest rates could further lower the cost, improving returns to the producers, pipeline owners and the State of Alaska.
- 4) Alaska State government needs to facilitate bringing the parties together to conclude a marketing agreement and to consider committing Alaskan royalty gas to the project.
- 5) A project labor agreement needs to be negotiated to ensure maximum local and native hire.
- 6) The Governor of Alaska, working with the President of the United States needs to continue and to expand their efforts to promote this **American** gas project.

It is clear that the people of Alaska have a large stake in employment, state and local revenues, and access to the gas which this project represents. All efforts should be made to expedite a trans Alaska gas pipeline to meet the 2003 to 2004 Asian market window.

Grass Roots LNG Projects

Cost Comparison

Project	Production (MMTPA*)	Estimated Cost \$ Billions	Cost in \$ Billions per MMTPA	Capital ** per MMBTU
Alaska TAGS	15	13.6	0.91	0.70
TAGS at higher cost	15	15.0	1.00	
Qatargas	6	6.0	1.00	
Natuna Island	15	21.3	1.42	1.00
Sakhalin	6	7.9	1.32	1.00

* million metric tons per annum

** does not reflect capitalized interest, cost of gas, time value of money or operating exp

TAGS Competition is Other Undeveloped Gas Fields in:

	<u>Start-up Date</u>	<u>Annual Volume</u>
▲ Qatar (Qatargas & Rasgas) - Mobil	2005	6-10 MMTA
▲ Indonesia (Natuna Island) - Exxon	2004	15 MMTA
▲ Sakhalin (Russia) - Exxon x2, Marathon/Shell	2004	15 MMTA
▲ Yemen - Exxon	??	15 MMTA
▲ Papua New Guinea - BP	??	15 MMTA
▲ Oman - Shell	2005	6 MMTA
▲ Australia - Shell, BP	2003	16 MMTA

Each host country (together with the private gas producers shown above) is actively promoting its project as the next post-2000 LNG supplier to Asia.

established by Congress be followed and the information and recommendations derived from that process be considered prior to congressional action that would affect those forests.

Congress has passed the National Forest Management Act and the National Environmental Policy Act, which establish an open public process for deciding how national forests should be managed. This process should be used to guide the congressional decision-making process.

5) Effect of National Policies on Forest-Dependent Communities

- The League urges the Alaska Legislature and the Governor to work with the congressional delegation and federal resource-management agencies to help broaden their understanding of the adverse impact of national policies on Alaska's forest-dependent communities. (11/ 93)

4. Oil, Gas, and Mineral Resources:

a. Arctic Oil Reserve (formerly Arctic National Wildlife Refuge (ANWR)) - The League urges the Congress of the United States to open the Coastal Plain of the Arctic Oil Reserve to environmentally responsible oil and gas exploration, development, and production. The League urges the State of Alaska to redistribute federal mineral revenue sharing funds to local governments, and strongly supports the 90-10 split as required by the Statehood Act.

b. Exploration and Development - The League encourages the State of Alaska to promote environmentally responsible oil, gas, and mineral exploration and development that is not detrimental to Alaskan fisheries.

c. Export of Oil - The League urges Congress to lift the ban on the export of North Slope crude oil. (11/ 92)

d. North Slope to Valdez Natural Gas Pipeline - The League strongly endorses the construction of a natural gas pipeline and associated liquefied natural gas (LNG) facilities at the very earliest possible date.

In order to meet the Asian market need, the League encourages all potential participants in this vital project to direct future efforts towards using approved environmental permits and export authorizations which allow construction to proceed in the existing, Congressionally approved north-south transportation corridor. The League recognizes that the only market for this major undeveloped resource will open in Asia shortly after the year 2000 and that strong competition from other potential suppliers on the Pacific Rim and the Middle East exists to meet this demand. The League, therefore, strongly

By: Dan LaSota
Introduced: 1/25/96

RESOLUTION NO. 96-009

A RESOLUTION SUPPORTING HOUSE JOINT RESOLUTION NO. 54 PENDING IN
THE LEGISLATURE OF THE STATE OF ALASKA PERTAINING TO THE
DEVELOPMENT OF THE TRANS-ALASKA GAS PIPELINE AND LIQUID NATURAL
GAS SALES

WHEREAS, HJR 54 has been introduced in the Alaska State Legislature and has been referred to three committees; and

WHEREAS, HJR 54, in part, calls for the Alaska State Legislature to "respectfully request the North Slope natural gas lessees to intensify their efforts to establish satisfactory contractual relationships for transportation and sale of Alaska North Slope Gas to Pacific Rim purchasers as soon as possible"; and

WHEREAS, the Assembly has recently adopted Resolution 95-081 calling for the Legislature to withhold financial incentives from North Slope Oil producers until they make Alaska North Slope Gas available for sale; and

WHEREAS, the Borough believes that development of the Trans-Alaska Gas Pipeline through the existing pipeline corridor is essential to the future economic health of the State of Alaska; and

WHEREAS, the Borough believes that it is also essential that labor for any project, especially of this scope, come from the skilled and ready work force that already exists in the State of Alaska; and

WHEREAS, the language of HJR 54 as it was introduced does not contain references to local hire or specify the desired location of the proposed Trans-Alaska Gas Pipeline.

NOW, THEREFORE, BE IT RESOLVED that the Fairbanks North Star Borough Assembly respectfully urges passage of HJR 54 with appropriate consideration given to Alaska hire and locating the project through the existing pipeline corridor.

BE IT FURTHER RESOLVED that copies of this resolution shall be sent to the Honorable Tony Knowles, Governor, State of Alaska, the Commissioner of Natural Resources, and members of the Alaska State Legislature.

Congress of the United States
House of Representatives
Washington, D.C. 20515
November 4, 1994

The Honorable William J. Clinton
President of the United States
The White House
Washington, D.C. 20500

Dear Mr. President:

We are writing to urge you not to attend the signing of the Natuna Sea natural gas agreement between the Exxon Corporation and the government of Indonesia.

Production in America's domestic oil and gas industry is at its lowest level since the Arab oil embargo. More than 430,000 jobs have been lost.

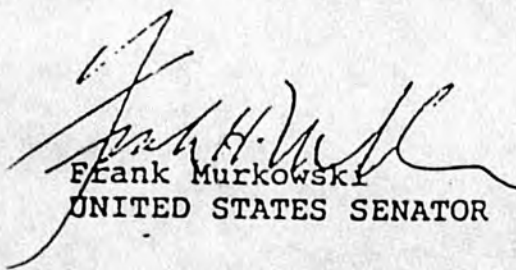
Proven natural gas reserves of more than 37 trillion cubic feet are waiting to be developed on Alaska's North Slope. The development of these reserves has the potential to create 30,000 American jobs immediately and generate \$500 million in Federal tax revenues. The trade deficit -- particularly with Japan -- would fall by as much as \$4 billion.

Exxon already owns 40 percent of the natural gas on the North Slope of Alaska. The Trans-Alaska Gas pipeline does not require any further licensing or approval and would be built in an existing pipeline corridor. It would greatly benefit from the support of your Administration, support which you have provided in the past for this clean, environmentally sound energy source.

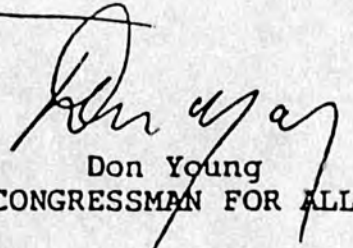
We ask that you not promote the export of American jobs by attending the signing of this agreement. The natural gas resources are readily available in America, and they can be developed in a far safer and more environmentally sound manner by our domestic industry.

We ask that you give your strong support to the development of Alaska natural gas instead.

Cordially,


Frank Murkowski
UNITED STATES SENATOR


Ted Stevens
UNITED STATES SENATOR


Don Young
CONGRESSMAN FOR ALL ALASKA

Gas Flares on the Slope

Uncertainty continues to cloud the future for Alaska's natural gas. The changing economics of the North Slope are upsetting the relationship between the Big Three producers, and while everyone agrees that someday Alaska will sell LNG to the Pacific Rim, how and when this will happen is still in dispute.



George Herben/BP Exploration (Alaska)

Trans-Alaska pipeline crossing Isabel Pass. One proposed gas pipeline route would parallel the oil pipeline.

By Ray Tyson

After years of internal studies and debate, Prudhoe Bay owners Arco Alaska, BP Exploration (Alaska) and Exxon head to the Pacific Rim this month to begin laying the market

foundation for what could lead to a major gas sale and perhaps the state's last megaproject.

But as the Big Three prepared to depart, questions remained as to the project's viability and ultimate success.

Many doubts were raised by producers themselves in July when they

broke silence on the issue, declaring the \$16 billion project to transport Prudhoe Bay natural gas via pipeline and ocean tankers to Asia commercially unworkable for at least another 10 years.

Arco Alaska president Ken Thompson and BP Exploration presi-

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dent John Morgan say an Alaska project that produces 14 million tons of liquefied natural gas (LNG) a year is simply unable to compete with similar world-class projects in Indonesia, Malaysia, Australia and Qatar, to name a few.

"That's like dumping on the market another 25 percent of the supply," Thompson says. "What happens when you dump that much LNG on the market at one time? (Gas) prices go south."

There are other producer concerns. Morgan and Thompson emphasize that before their companies OK a major gas sale, estimated project costs must be reduced, the state must assure a stable tax and royalty climate, and market demand must be confirmed.

"None of us is terribly keen to go into the next phase of engineering expenditure until we can demonstrate to ourselves and to others that those basic conditions are in place, or have a very good chance of being in place," Morgan says.

Oil vs. Gas

Meanwhile, industry observers are questioning producer motives at Prudhoe Bay, wondering how a growing conflict of interest between the principle owners of the field's gas rim. (Arco and Exxon) and the oil rim (BP) will affect the timing and success of a major gas sale in the Pacific Rim.

Arco and Exxon each own about 42 percent of the gas, compared to BP's 14 percent, while BP owns 51 percent of the oil, compared to Arco's 21 percent share and Exxon's 21 percent share. In effect, gas is increasing in value as North Slope oil production declines, a fundamental shift in oilpatch economics that appears to favor Arco and Exxon in the long haul.

The issue came to a head earlier this year when Arco, operator of the Central Gas Facility at Prudhoe Bay, petitioned the Alaska Oil and Gas Conservation Commission to increase production of natural gas liquids (NGLs), which are blended with crude oil from North Slope fields before shipment through the

trans-Alaska oil pipeline.

Arco and Exxon argued that increasing NGL production, made possible by the massive GHX gas-handling project, would benefit the state as well as the producers because it would serve to prop up waning North Slope yields of just more than 1.5 million barrels a day.

BP protested, contending the use of additional NGLs would deplete the gas stock from which miscible injectant is manufactured. The detergent-like substance greatly enhances oil recovery after it is injected into the reservoir.

After a long hearing on the issue, the commission sided with Arco and Exxon, ordering field operators to increase NGL production "to the maximum volume that can be tendered" to the pipeline, from peaks of 74,000 to 94,000 barrels per day.

In its ruling, the commission also called attention to the growing competition between the oil rim and the gas rim, noting the competition has "compromised conservation principles in the development and operation of the Prudhoe Bay Pool." "There needs to be a common equity for distribution of both the oil and gas," commission chairman Dave Johnston warns.

NGL vs. LNG

NGL that goes into the pipeline is an entirely separate product and issue than shipping LNG to the Pacific Rim. Because of their large stake in the gas cap, however, it appears Arco and Exxon would favor a major LNG project earlier than BP would like.

Prudhoe Bay alone contains an estimated 26 trillion cubic feet of natural gas, about 20 trillion cubic feet of which would be available for sale to markets in Japan, Korea and Taiwan. Aside from gas used for NGLs, miscible injectant and field operations, most of it is reinjected, serving to maintain reservoir pressure for oil production.

Prudhoe Bay field operators Arco and BP now say that their 2005-2010 timeframe for a major gas sale would result in a minimal oil loss and would not factor into their decision to move

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ahead with an LNG project.

Upon a closer examination of their answers to questions posed at a press briefing on the project in July, however, Thompson appeared to favor a period closer to 2005, while Morgan said the market window for Alaska LNG "probably" would be "toward the back end of that 2005 to 2010 period."

In any event, the producers' post-2005 timetable for a gas sale drew an immediate reaction from Yukon-Pacific, a business unit of transportation conglomerate CSX that has spent years acquiring the necessary government permits for its proposed Trans-Alaska Gas System which would distribute North Slope gas to the same markets targeted by Arco, BP and Exxon.

Yukon Pacific contends the 2005-2010 timeframe proposed by the gas owners is highly risky, primarily because it doesn't jibe with the annual 30 million tons of LNG shortfall the company says will be filled earlier by overseas projects competing for Asian LNG markets.

"Without question the Japanese, Koreans and Taiwanese need LNG," says Jeff Lowenfels, Yukon Pacific's outspoken president.

"We would say commencing around 2003 is when they really need to start obtaining new sources of LNG. There absolutely is every reason to believe that the demand we seek to fulfill will be filled by a competing project if we wait. It's completely disingenuous to suggest there is not room for 14 million tons (a year) from Alaska."

Lowenfels says his company's supply/demand assessment is based on exhaustive studies and 51 marketing trips to Asia during the past five years alone. The producers are making their first joint visit to the marketplace.

"I think they are going to discover . . . there is a market and a great deal

of willingness to discuss how to put this project together and how to do it as quickly as possible," Lowenfels says.

Plans and Schemes

But he warns that to beat the competition, Alaska must have a specific plan or "project scheme" for the markets to consider, including a permitted overland route and other government approvals.

"There absolutely is every reason to believe that the demand we seek to fulfill will be filled by a competing project if we wait. It's completely disingenuous to suggest there is not room for 14 million tons (a year) from Alaska."

JEFF LOWENFELS
PRESIDENT, YUKON PACIFIC

of willingness to discuss how to put this project together and how to do it as quickly as possible," Lowenfels says.

Bay along the existing pipeline route south to tidewater at Valdez. Yukon Pacific holds permits for the southern route as well as for an LNG export site at Anderson Bay near Valdez.

Because of difficulties in acquiring government permits, coupled with the lead time needed to finance and construct a multi-billion dollar project, the producers have no viable alternative other than to deal with Yukon Pacific on a southern route, Lowenfels contends.

"Let the negotiations begin," Lowenfels declares. "These permits don't appear out of the blue, and I don't care who is working them. You can forget their (marketing) deadline ever being met if they don't use the existing permits."

The producers have given Yukon Pacific less than a ringing endorsement, only saying they are willing to discuss the project with any potential investor, including Yukon Pacific.

However, "We do need to sit down with Yukon Pacific to fully understand their permits and permit terms, to see if they are as applicable

to the exact options that we see to the south," Arco's Thompson concedes.

The producers say that for the moment, they also will continue to study a western route option, a plan that would require a pipeline only about half the length of an 800-mile pipeline going south. But crossing the National Petroleum Reserve with a pipeline would require Congressional approval. And after reaching the coast, the LNG would have to be loaded aboard special ice-breaking tankers for the long ocean crossing.

Even with a longer pipeline, a southern route that would parallel the existing oil pipeline appears to be the most likely option, the producers suggest.

"A significant part of the cost savings we have identified has to do with maximizing the level of integration between new facilities and existing facilities," BP's Morgan says.

In fact, the producers say that through sharing existing infrastructure, using larger LNG ocean tankers and employing new pipeline construction techniques, they may be able to shave \$3 billion off the \$15 billion in estimated project costs.

"We're not giving up," Arco's Thompson pledges. "We can see that we must move forward to try and innovate what we can . . . to see if we can be a competitive project post 2005."

And while an Alaska project has its disadvantages, Morgan adds, it also has its advantages over other projects. He says, "We have an existing field development and we know the gas reserves are there . . . and we are closer to market than a number of the Middle East schemes."

Certainly a major part of the effort to make an Alaska LNG project competitive rests in the markets, largely made up of utility companies in the energy-starved Pacific Rim.

Says Thompson, "We feel at this time the producers should be talking more openly with the market. We want to contact key leaders with utilities, as well as government, to tell them where we stand on this project, to tell them what we see as the hurdles, to see what ideas they may have, and also to confirm what views they have about LNG supply and demand."

**THE FOLLOWING DOCUMENT
HAS NOT BEEN FILMED
BUT IS AVAILABLE IN THE
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TRANS-ALASKA GAS SYSTEM



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Report of Investigations 95-11

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

by

Richard W. Kornbrath



Published by

**STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES**

**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*

1995

This DGGS Report of Investigations is a final report of scientific research. It has received technical review and may be cited as an agency publication.

Report of Investigations 95-11
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Cost \$3.00

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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,

¹Division of Oil & Gas, 3601 C Street, Suite 1380, Anchorage, Alaska 99503.

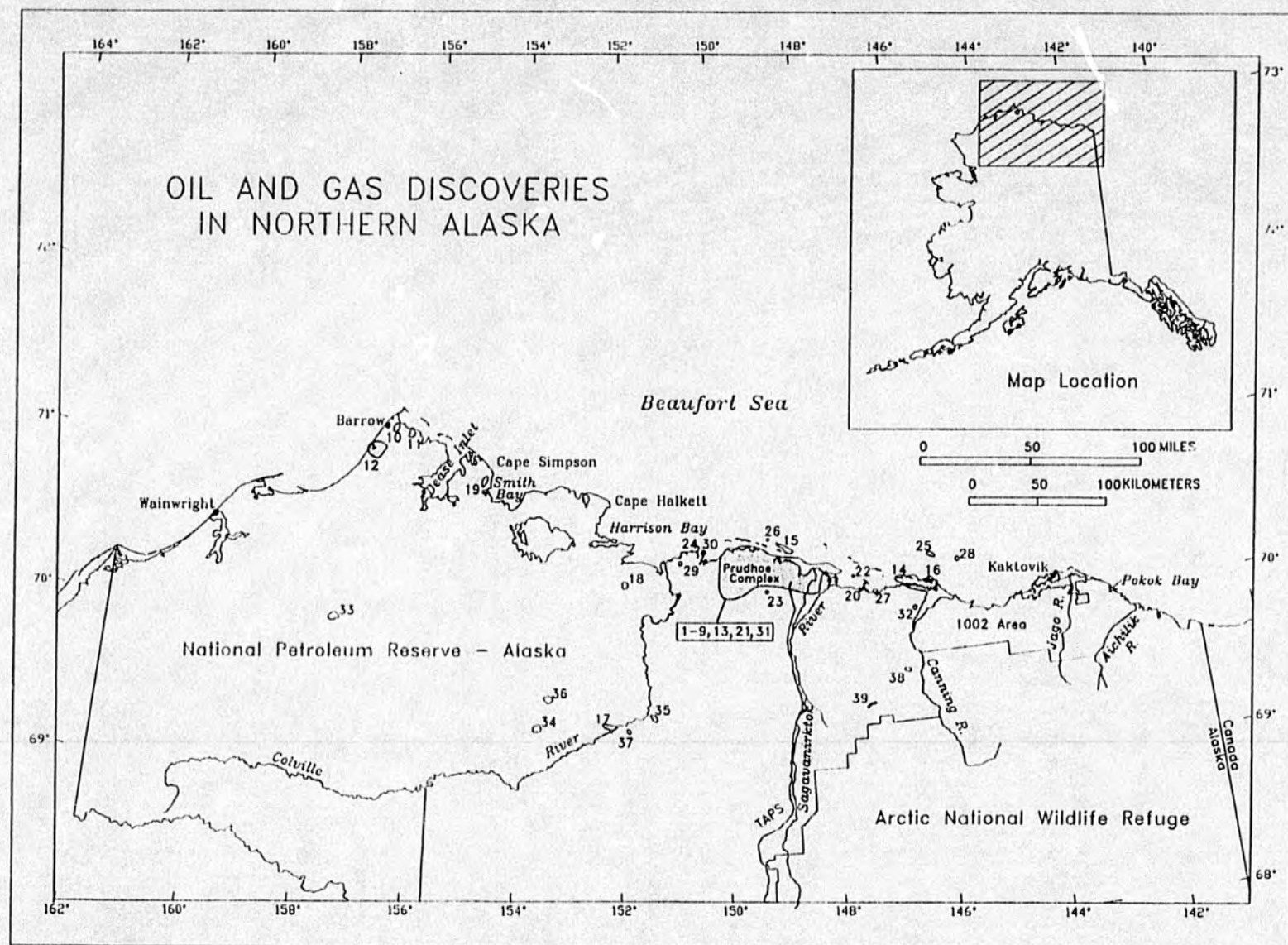


Figure 1. Oil and gas discoveries in northern Alaska. (The numbers by the discoveries are keyed to table 9.)

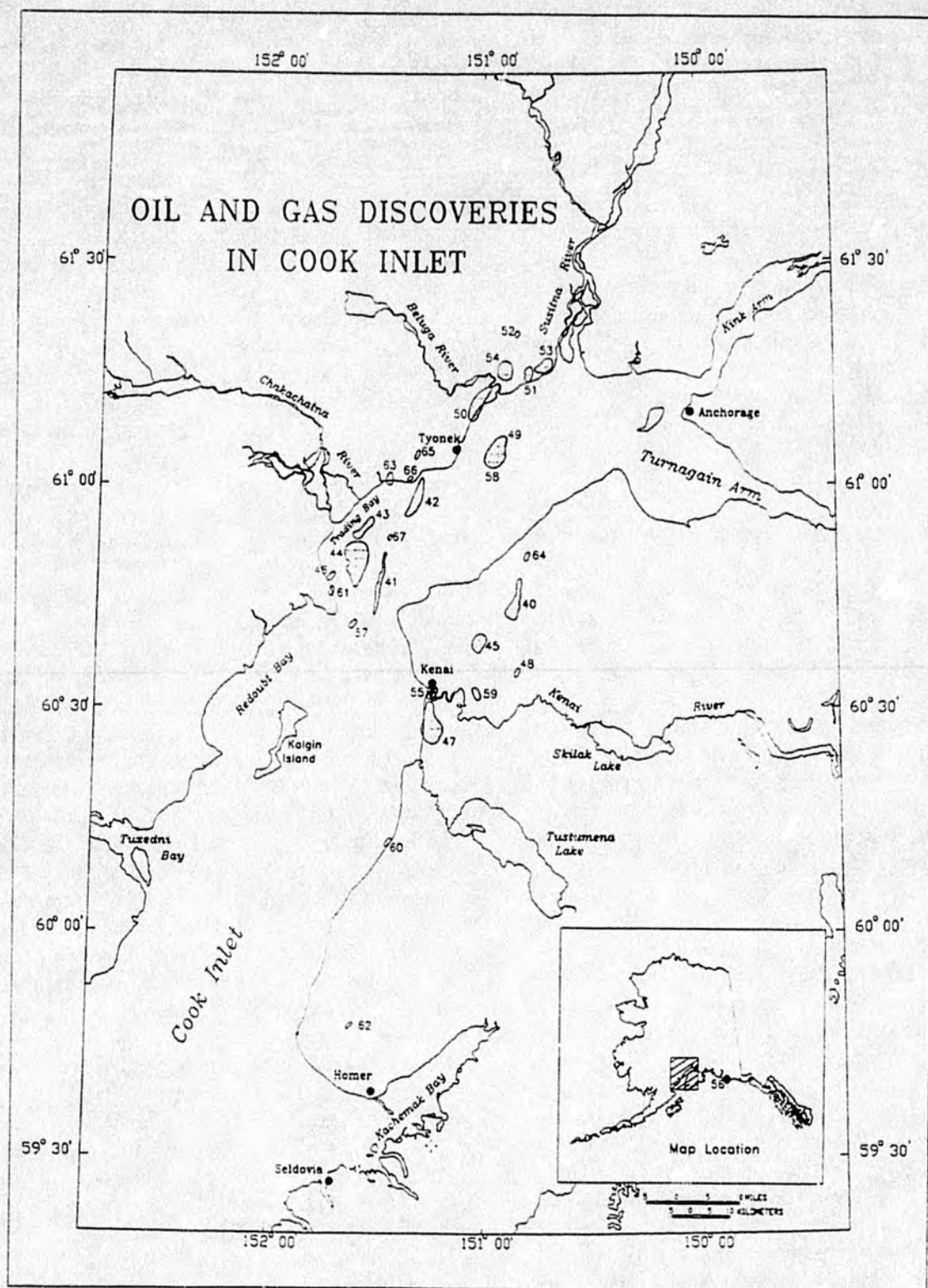


Figure 2. Oil and gas discoveries in Cook Inlet. (The numbers by the discoveries are keyed to table 9.)

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	Niakupuk ^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	Undvlpd	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 (°)^e Just Cook Inlet, defined by lat 58.5°-62° and long 149°-153.5°^f Same as (°)

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%

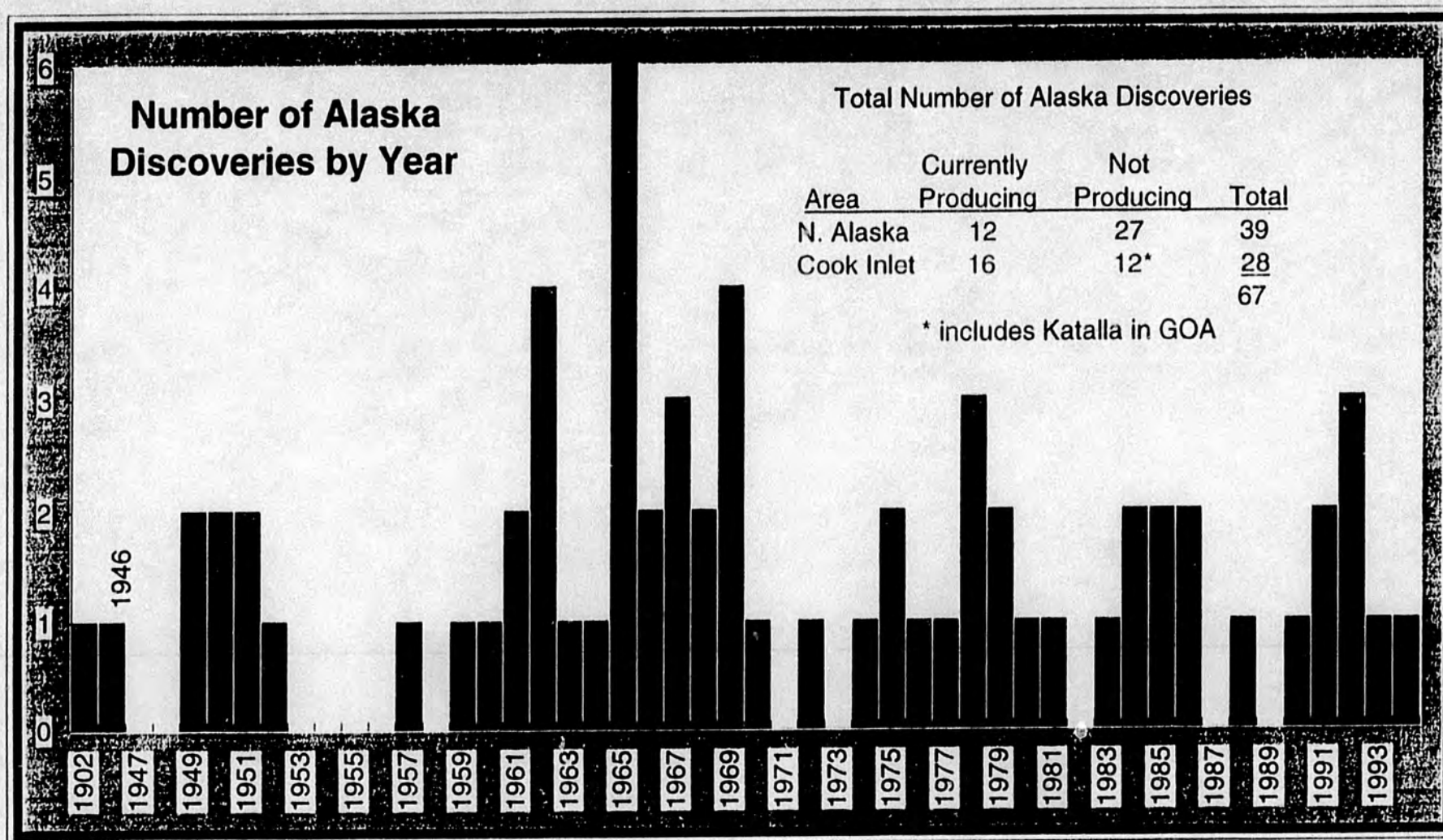


Figure 3. Number of Alaska discoveries by year through April 1994.

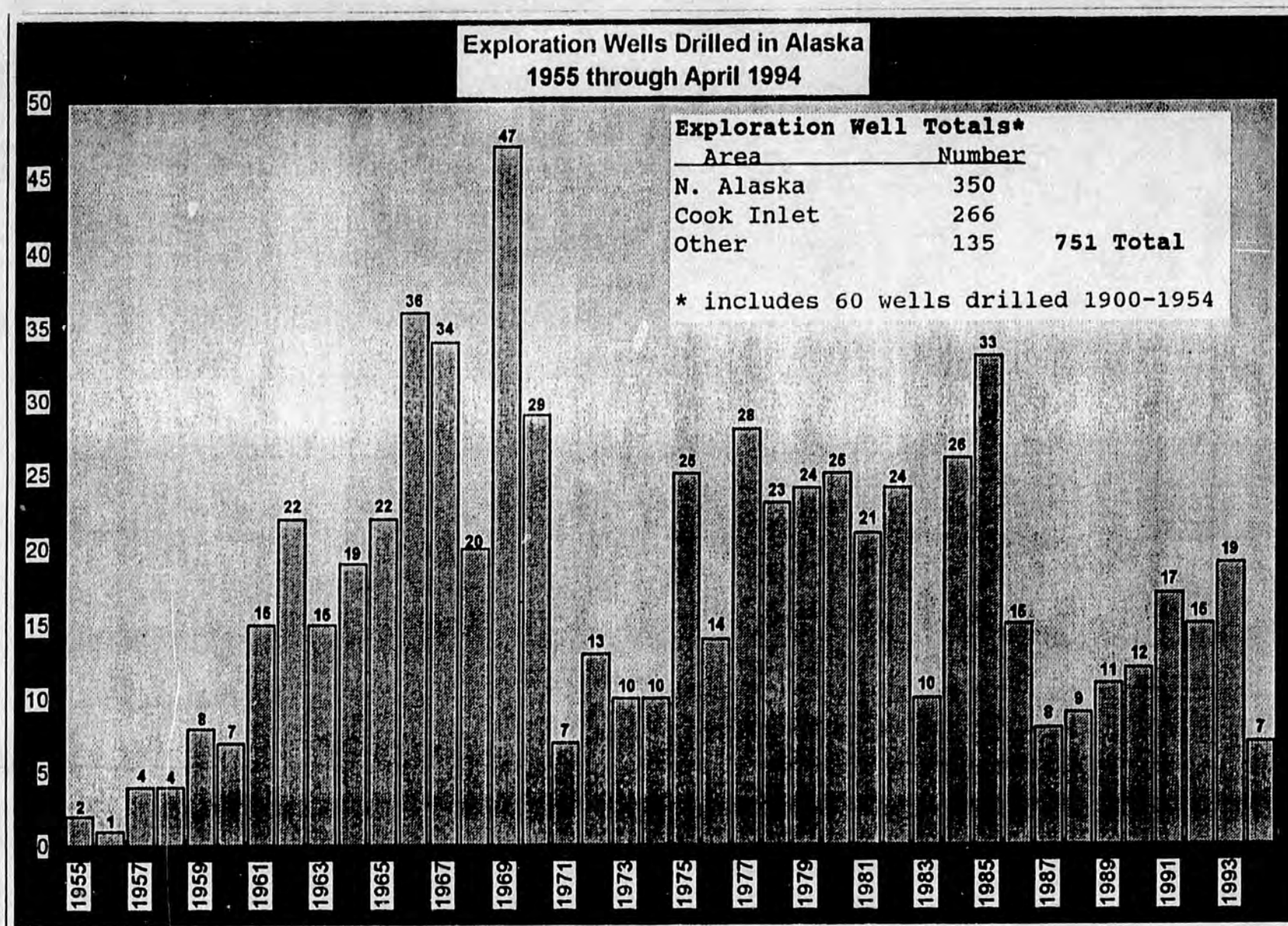


Figure 4. Exploration wells drilled in Alaska through April 1994.

**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
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for
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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

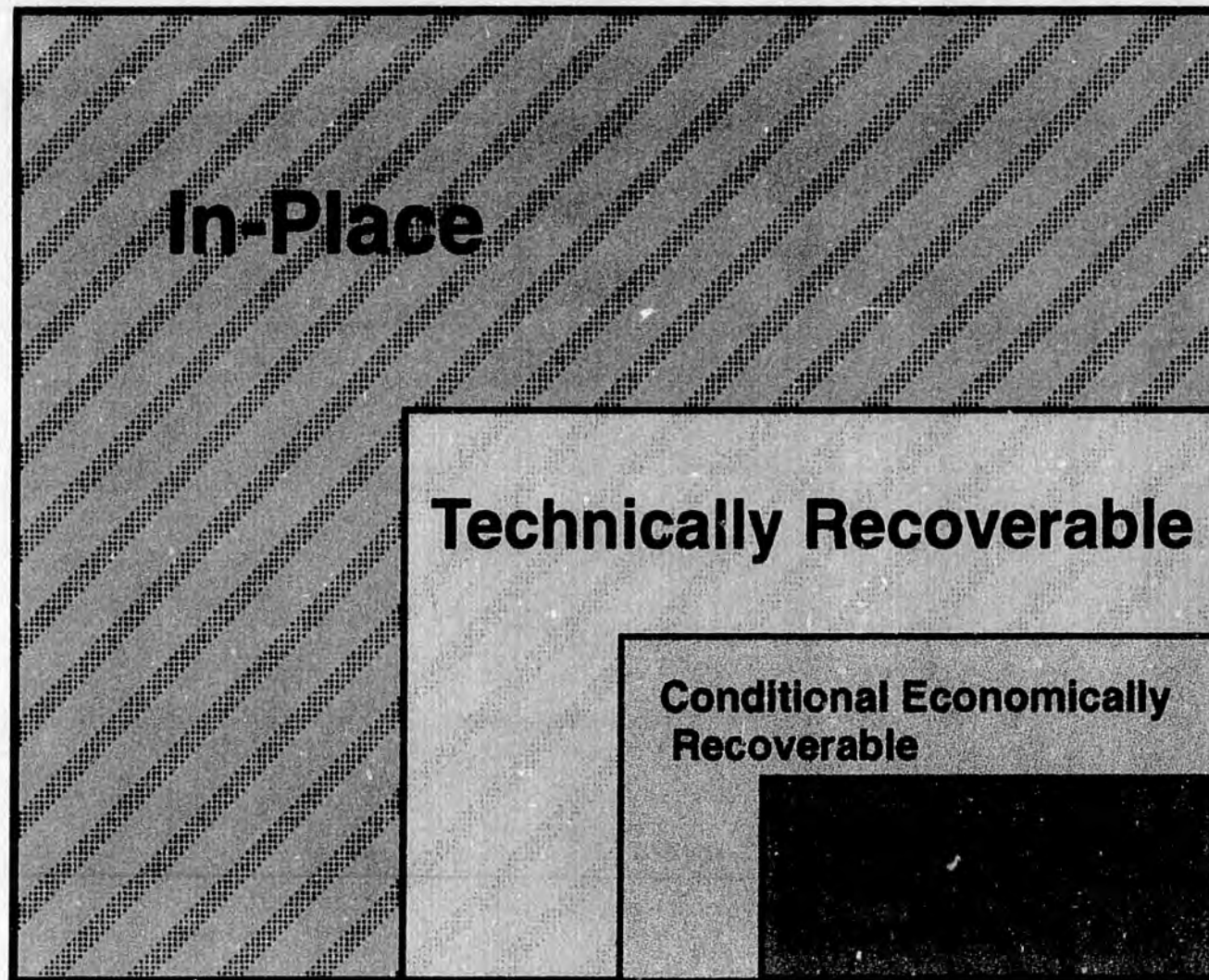
**Measured
(Proved)
Reserves**

**Inferred
Reserves**

Undiscovered Resources

Economic under existing conditions

**Possible additional recoverable oil
in known fields**



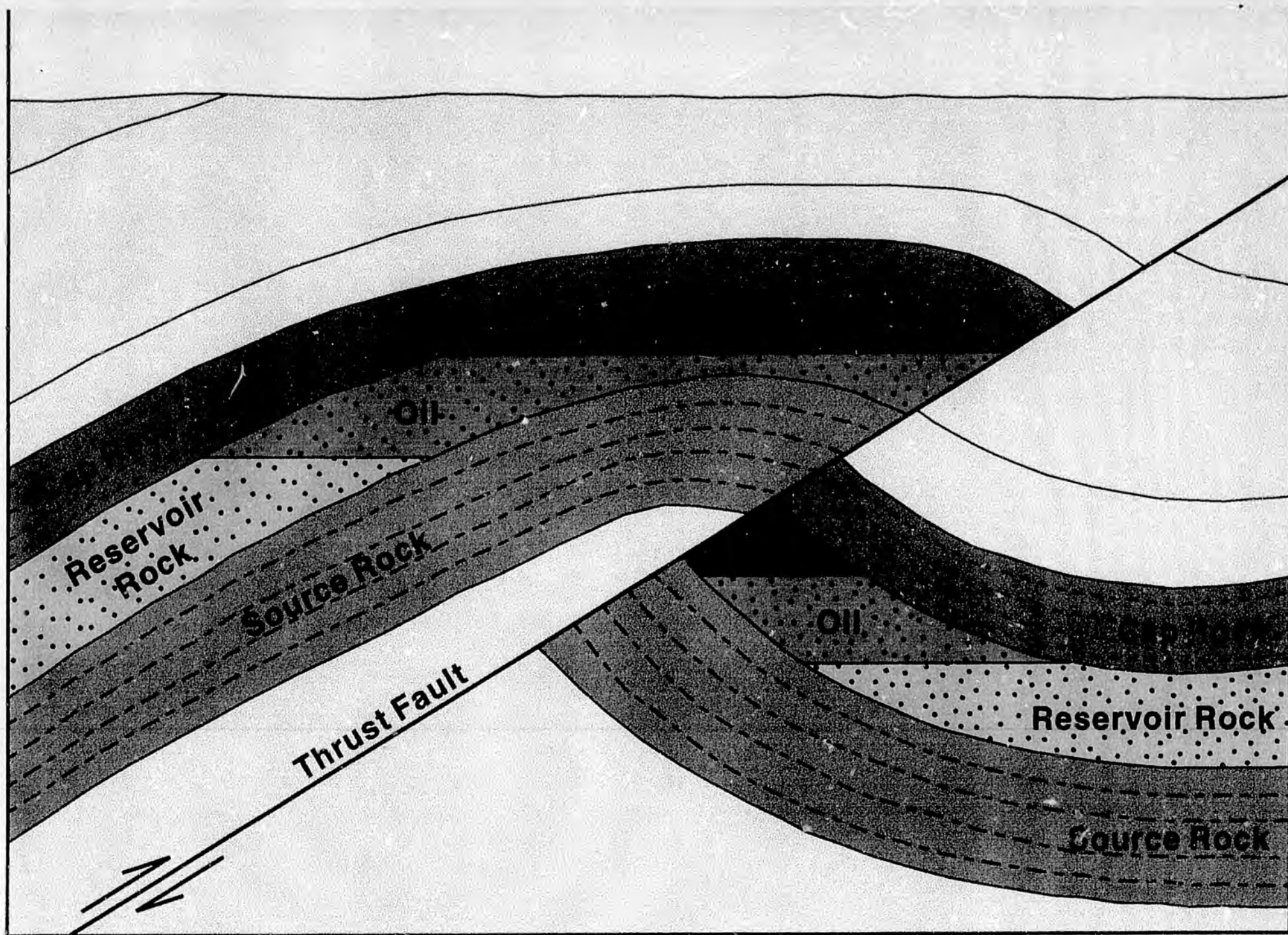
Known

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.