But it is possible to explore too much and - equally wasteful - too soon. I have discussed selecting a year of discovery when the present value (PV) of a mine net of discovery costs stopped growing faster than the rate of interest. Figure C.4 shows the relevant quantities.

The "Moving Present Values" (MPV) are present values computed as in Figure C.3 (p. 349). Each is the maximum PV (R-C) that could be achieved by beginning production in the current year. By waiting, this value rises if costs are falling or prices rising, as shown. This is what makes lease values rise, and makes owners hold them for the rise, for lease values represent the net value of a resource after all non-land costs*.

Since this is a net value after all costs, including interest costs on non-land outlays, it is socially desirable to conserve the resource so long as its appreciation outpaces the relevant market interest rate. The time to begin discovery and development is when the lease appreciation slows down to the interest rate or less.

That is the year in which the non-moving PV of the lease is a maximum (A). On Figure C.4 this stationary PV is based on the origin, 1966, but any other year would do as well.

It would not make sense to hold the lease until its MPV was a maximum. That might be never; and in any case it would deprive us of interest on the net value of the resource in situ.

It would not make sense to develop the lease as soon as it assumed any spot liquidation value (C), for it is then of negligible current net value, but appreciating much faster than money in the bank.

It would make even less sense to develop the lease at the time D (not shown in Fig. C.4) when it first developed a perceptible market value. D would come before C.D would be the year in which the remote future possiblity of rent-yielding mineral development was first faintly suspected. For a future net value, once foreseen, always has some present value, however small.

A tax that takes a fixed percentage of the rent will lower the absolute but not the percentage growth of MPV (R-C) and so leave unchanged the date of A, the time to begin exploration and development.

*In a perfect market, however, lease values will not rise as fast as MPV(R-C). Rather, they would grow exactly at the rate of interest, along the compound interest curve in Figure C.4B. The expectation of future value assumes a present value some years before the optimal date to begin liquidation, as shown. The conditions under which leases are written, however, probably do not allow full expression of those foreshadowed values in the market for leases. Rather, they show up in inflated prices for range land, reservations of mineral rights, etc.

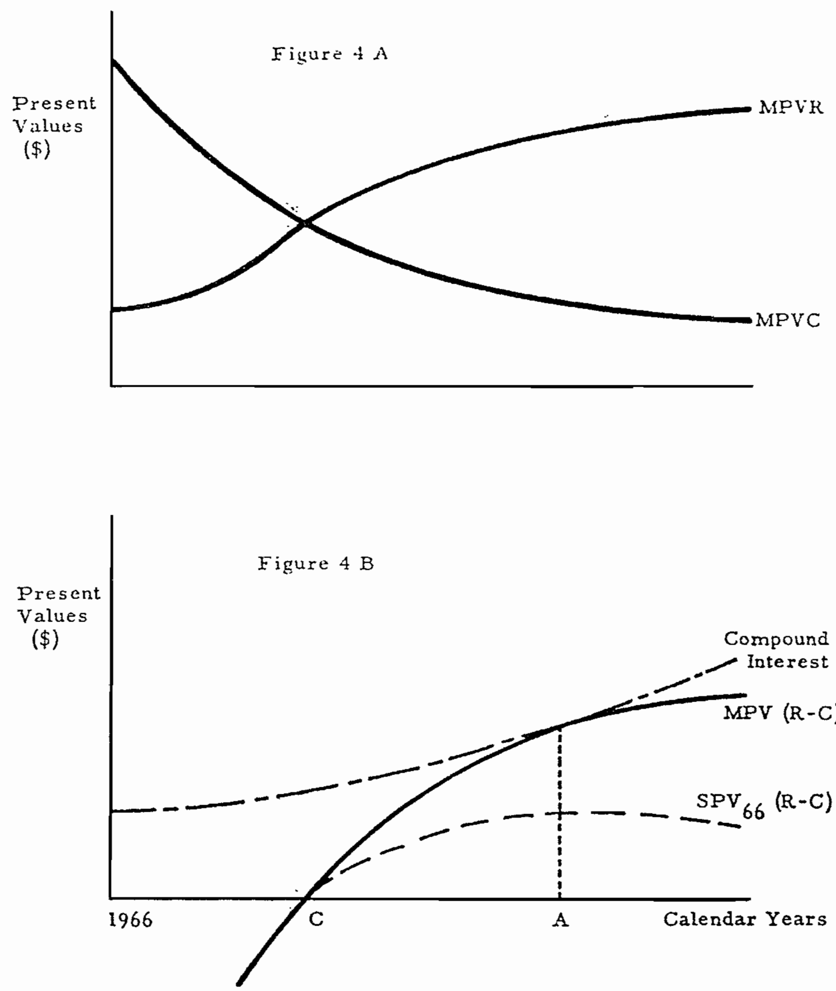


FIGURE C.4

Moving Present Values (MPV) of Revenues and Costs of Mineral Discovery and Development; and Stationary Present Value (SPV) of Revenues Minus Costs (R-C) Referred to a Base Year, 1966

Appendix B

Changing reserve-output ration (R:O) is slow, especially when it is long to begin with.

Another distinctive feature of the staggered model is the lag it implies in adjustment to new conditions. If interest rates fall, prescribing longer lives and higher R:O, the miner's primary adjustment is building less capacity and longer life into new mines. The life of old ones is largely determined by the original capacity, which not reviewable until the new replaces the old. It takes mining longer to respond to new economic stimuli, therefore, than it takes the new stimuli to be replaced by still newer ones, so the industry is chronically maladjusted, lagging its times by many years.

It is not really staggering as such, but time-indivisibility, that causes the lag. If we had 40 even-aged mines of 20-year life we could not adjust any mine at all, except one year in 20 when we could change every one. Staggering merely spreads this problem evenly so that each year we can make some change.

Staggered or not, a longer life of mines means a longer lag in adjusting to changed parameters. Oil reserves queued up behind shafts of low capacity are by no means on tap to meet emergency needs, either for minerals in particular or capital in general. Today interest rates stand double what they were fifteen and twenty years ago. Many mines and wells producing today are geared to that slower pace. The owners cannot benefit from earlier recovery of their money, and needy borrowers cannot benefit from the additional funds thus released.

The comforting thought that long reserves give us great flexibility to meet contingencies we must partly abandon, therefore. There is some short-run flexibility in each given mine, but it is not increased by having longer reserves behind each mine. Most of the adjustment occurs in the new mine opened yearly.

This adjustment is in fact slowed by longer reserves. With 40-year life of the representative staggered mine, and one mine turnover yearly, we retire and replace 1/40 of our output yearly and complete the changeover in 40 years, by which time, no doubt, new adjustments will be long overdue. With 20-year life it takes 20 years, and so on. With the shorter life, and still 40 mines, we must now retire two yearly; or we could get along on fewer mines (and somewhat larger jolts to our going concern). But no matter; in either case a shorter initial life means faster turnover and faster response to new economic stimuli.

The adjustment from longer to shorter reserves may be rapid if we drop the assumption that each producing mine finish out its pre-ordained life cycle before replacement. An owner with very long reserves behind his mines in effect has completely idle, uncommitted reserves which he can bring to life quickly. An 80-year reserve behind one mine, for example, is more like one 40-year reserve and one idle deposit, and this owner can double output by throwing the uncommitted 40-year units into the breach. Forty years is long enough to exhaust most economies of longevity in mine capital. He simply needs to duplicate existing capital and double output.

Thus a firm of high R:O can break the pattern of perfect staggering and by an energetic wrench increase output promptly. Anaconda Copper, which has 40 percent of world copper reserves compared to less than 14 per cent of the output, is currently investing heavily in new mine improvements to raise output by 50 percent from existing reserves (35)--simple enough when your R:O is more than four times the rest of the industry's. But that is better conceived as putting idle reserves to use than as shortening a systematic pattern of staggering. In the absence of idle reserves, a faster turnover clearly accelerates change, and thus substitutes for holding sterile reserves. A high turnover firm or industry achieves its adaptability by subjecting a high percentage of its production to redesign each year, a procedure which achieves the end without the high social cost of idle reserves.

The adaptable firm also needs to be able to reduce output quickly in response to lower prices. A firm needs no advance reserves to do that; but the shorter reserves it has, the higher percentage of its capacity it retires each year. Furthermore, mines of few years of future life (YFL) can economically be turned on and off in response to changing relations of present to future prices. A small price advantage is enough to warrant substituting near-future production for present production. With longevous mines, on the other hand, sacrifice of present production adds nothing to near-future production, but only to remote future production whose present value is too low to be worth much present sacrifice.

The adaptable firm also needs to guard against obsolescence. Here again a short life of mine and a high replacement factor each year is the best policy.

Appendix C

Table C-1

Ranking of Oil Companies by Noncompetitive Total Acreage

		Individual	Cumulative	
Texaco	119,513.19	16.2%	16.2%	
Union	117,328.52	15.8	32.0	
Cities Service	70,006.91	9.5	39.5	
Amoco Production	53,851.94	7.3	46.8	
Atlantic Richfield	51,277.40	6.9	53.8	10%
Alaska North America	32,606.49	4.4	58.2	
Pan Ocean	32,081.00	4.3	62.5	
Beard	29,765.19	4.0	66.0	
Mobil	29,564.14	4.0	70.0	
Marathon	22,085.37	2.9	72.9	20%
Standard Oil of California	21,107.14	2.8	75.7	
Exxon	18,362.00	2.5	78.2	
Placid	14,769.00	2.0	80.2	
Brinkeroff	14,271.90	1.9	82.1	
Alaska Offshore	12,249.00	1.6	83.7	
Skelley	9,562.00	1.3	85.0	
Farmland	8,878.00	1.2	86.2	
Home Petroleum	8,862.00	1.2	87.4	
Amarillo	7,065.00	1.0	88.4	
Sun	5,000.00	1.7	89.1	
Tidelands	4,693.00	.6	89.7	
Inlet	4,130.00	.6	90.3	
Apco	4,130.00	.6	90.9	
Shell	4,034.00	.5	91.4	
Texas International	3,713.34	.5	91.9	
Clark	3,716.00	.5	92.4	
Ashland	3,101.62	.4	92.8	
Newmont	2,940.00	.4	93.2	
Columbia Gas	2,560.00	.4	93.6	
Dixie Gulf	2,560.00	.4	94.0	
Dome Petroleum	2,560.00	.4	94.4	
South States	2,560.00	.4	94.8	
BP Alaska	2,560.00	.4	95.2	
Ozark Refineries	2,487.00	.4	95.6	
Alaska Kenai	2,463.15	.4	96.0	
Burton Hawkins	1,920.00	.3	96.3	
Alaska International	1,760.00	.2	96.5	
Ampco American	1,640.00	.2	96.7	
Little Bear	1,440.00	.2	96.9	
Continental	1,343.15	.2	97.1	

(To be continued)

Table C-1 (continued)

		Individual	Cumulative
American Petrofina	1,280.00	.2%	97.3%
Anschutz Corporation	877.76	.1	97.4
Cache	640.00	.1	97.5
Derby Refineries	639.82	.1	97.6
Simasko	461.25	.1	97.8
Belco	70.52	Nil	
Salcha	37.75	Nil	
	738,524.55		

47 members so deciles will be rounded to every five members

Source of raw data: Pedro Denton, D.N.R.

NON-COMPETITIVE
TOTAL
ACREAGE

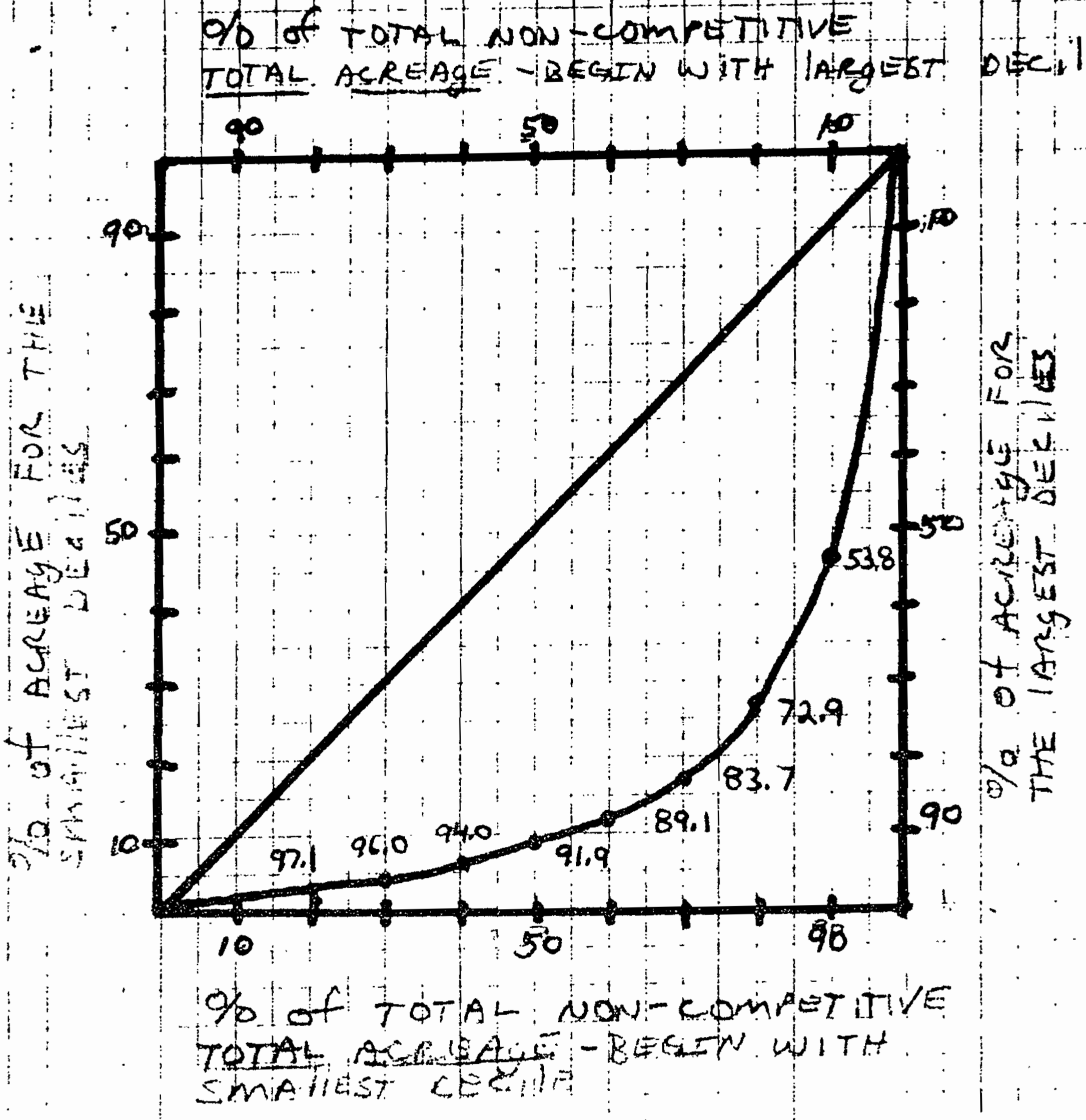


Table C-2

Ranking of Oil Companies by Noncompetitive Net Acreage

		Individual	Cumulative	
Texaco	113,238.64	18.1%	18.3%	
Union	109,809.97	17.5	35.6	
Cities Service	70,006.91	11.2	46.8	
Amoco	42,944.51	6.8	53.6	
Atlantic Richfield	33,402.30	5.3	58.9	10%
Alaska North America	32,666.49	5.2	64.1	
Pan Ocean	32,041.00	5.1	69.2	
Beard Oil	29,765.19	4.8	74.0	
Mobil	17,280.50	2.8	76.8	
Marathon	16,594.04	2.7	79.5	20%
Placid	14,769.00	2.4	81.9	
Brinkeroff	13,491.90	2.2	84.1	
Standard Oil of California	13,336.35	2.1	86.2	
Alaskan Offshore	12,249.00	1.9	88.1	
Exxon	10,102.00	1.6	89.7	
Skelly	9,562.00	1.6	91.3	
Farmland	8,872.00	1.4	92.7	
Amarillo	7,065.00	1.1	93.8	
Home Petroleum	6,515.25	1.1	94.9	
Tidelands	4,693.00	1.0	95.9	
Texas International	3,713.34	.6	96.5	
Clark	2,920.00	.5	97.0	
Dome Petroleum	2,560.00	.5	97.5	
South States Oil	2,560.00	.5	98.0	
Ozark Refineries	2,487.00	.3	98.3	
Burton Hawks	1,920.00	.3	98.6	
Phillips Petroleum	1,858.00	.3	98.9	
Alaska International	1,760.00	.2	99.2	
Ampco American Mineral	1,640.00	.2	99.4	
American Petrofina	1,280.00	.2	99.6	
Alaska Kenai	1,262.38	Nil		
Sun	1,249.51	Nil		
Shell	1,173.70	Nil		
Little Bear	1,140.00	Nil		
Apco	1,072.56	Nil		
Inlet	1,032.50	Nil		
Anschutz	877.76	Nil		
Ashland	811.75	Nil		
Newmont	730.29	Nil		
Continental	671.57	Nil		
Cache Investment	640.00	Nil		

(To be continued)

Table C-2 (continued)

		Individual	Cumulative
BP Alaska	544.00	Nil	
Simasko	461.25	Nil	
Columbia Gas Company	368.12	Nil	
Derby	255.93	Nil	
Dixie Gulf	200.00	Nil	
Belco	70.52	Nil	
Salcha	37.75	Nil	
	624,703.25		

48 members so deciles will be rounded to every five members

Source of raw data: Pedro Denton, D.N.R.

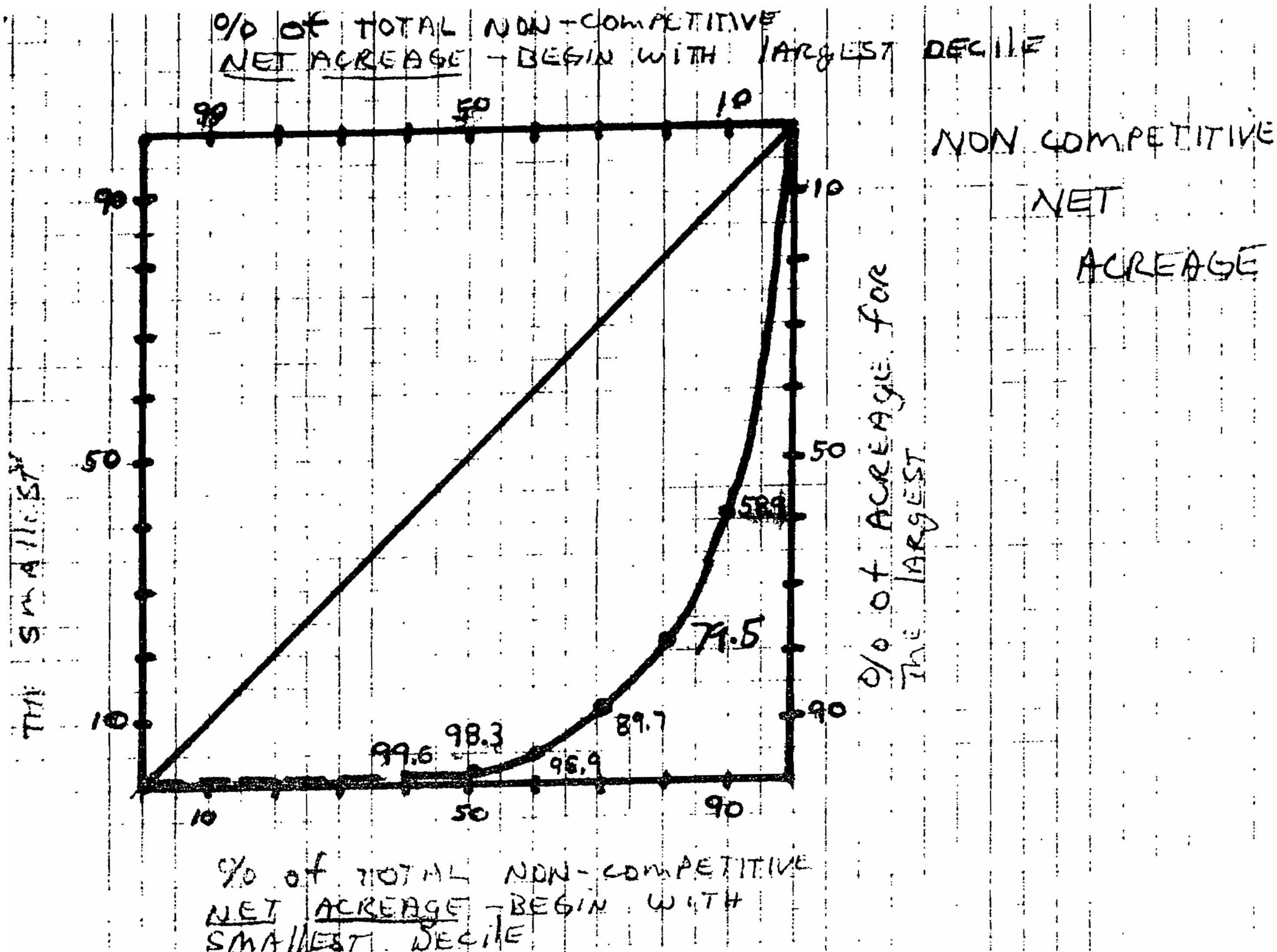

% of TOTAL NON-COMPETITIVE NET ACREAGE - BEGIN WITH LARGEST DECILE
90
50
10
90
50
10
10
50
90
58.9
79.5
89.7
96.9
98.3
99.6
10
50
90
% of ACREAGE for The LARGEST
The SMALLEST
% of TOTAL NON-COMPETITIVE NET ACREAGE - BEGIN WITH SMALLEST DECILE
NON COMPETITIVE NET ACREAGE

Table C-3

Ranking of Oil Companies by Competitive Total Acreage

		Individual	Cumulative	
Atlantic Richfield	937,724.22	17.8%	17.8%	
Sohio	447,674.00	8.5	26.3	
Phillips Petroleum	413,546.00	7.9	34.2	
Union	381,893.67	7.3	41.5	
BP Alaska	351,151.00	6.7	48.2	
Exxon	291,884.00	5.5	53.7	
Standard Oil of California	248,271.89	4.7	58.4	
Amoco	274,134.05	5.2	63.5	10%
Mobil	218,685.44	4.2	67.8	
Cities Service	139,284.93	2.7	70.5	
Continental	121,459.73	2.3	72.8	
Texaco	84,218.47	1.6	74.4	
Louisiana	80,161.36	1.5	75.9	
Shell	71,554.28	1.4	77.3	
Pennzoil	64,997.36	1.2	78.5	
Placid	60,669.36	1.2	79.7	20%
Marathon	60,529.20	1.2	80.9	
Amerada Hess	58,495.00	1.1	82.0	
Getty	58,454.00	1.1	83.1	
Newmont	45,828.71	.9	84.0	
Maruzen	43,297.44	.8	84.8	
Beard	40,855.00	.8	85.6	
Skelly	40,449.00	.7	86.3	
Gulf	38,994.71	.7	87.0	
Hunt Industries	38,129.00	.7	87.7	
Halbouty	29,291.35	.6	88.3	
Texas International	27,422.45	.5	88.8	
Simasko	26,956.16	.5	89.3	
Derby	23,753.00	.4	89.7	
Yates Petroleum	21,168.29	.4	90.1	
Hamilton Bros. N.S. Venture #I	20,464.00	.4	90.5	
Hamilton Bros. N.S. Venture #III	20,464.00	.4	90.9	
Carl Brewing	20,453.00	.4	91.3	
Oil Resources	20,453.00	.4	91.7	
Sunlite Nevada	20,453.00	.4	92.1	
Superior	19,163.00	.3	92.4	
Ulster	18,873.00	.3	92.7	
Westcoast	18,873.00	.3	92.7	
Ashland	18,691.08	.3	93.0	
Gas Supply	17,990.00	.3	93.3	

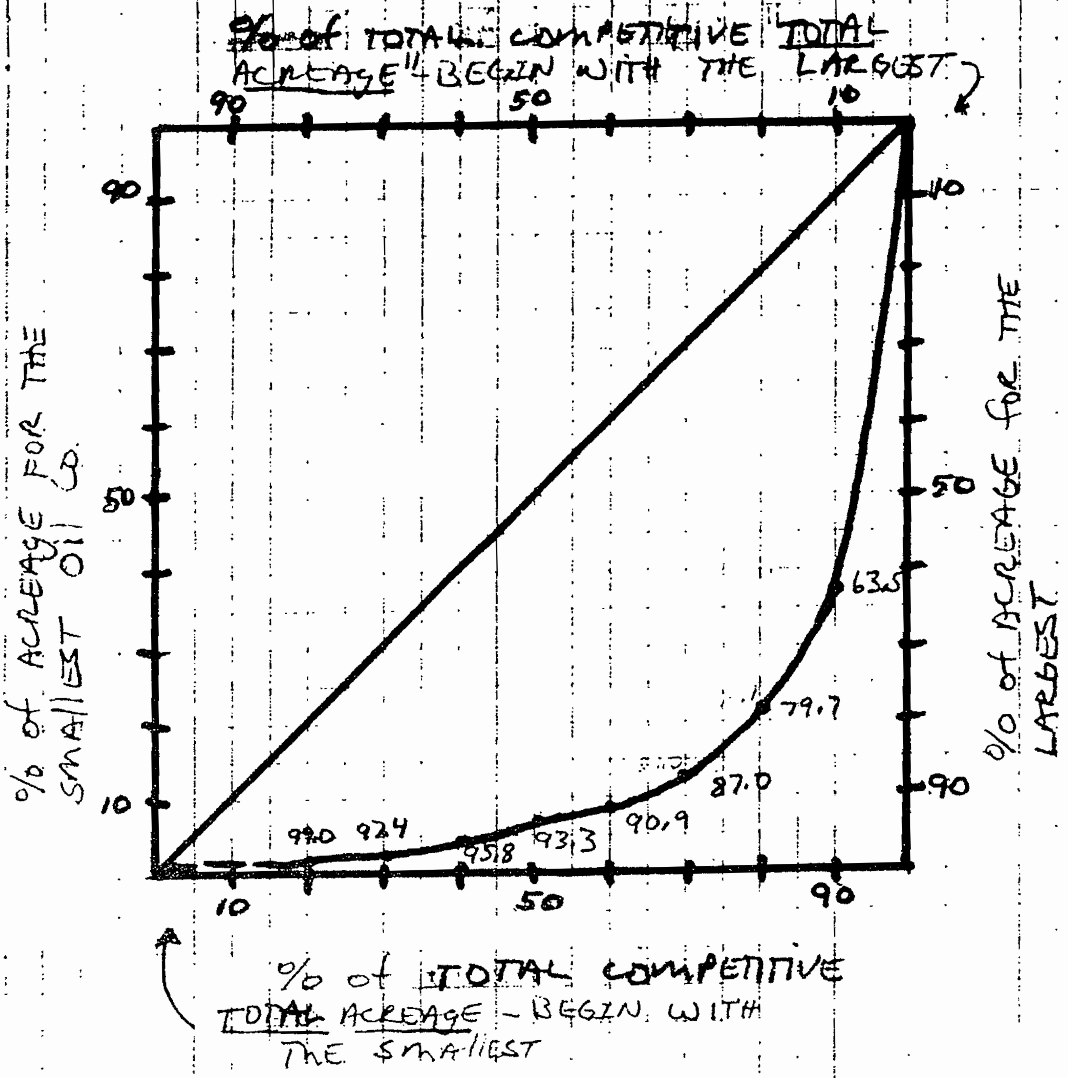
(To be continued)

Table C-3 (continued)

		Individual	Cumulative
Hamilton Bros. Oil and Gas Co.	17,334.00	.3%	93.6%
Amarex	16,412.00	.3	93.9
Coastal State	15,360.00	.3	94.2
Pacific Lighting	15,322.00	.3	94.7
Trans Ocean	14,729.00	.3	95.0
Hunt Oil	14,779.00	.3	95.3
Hunt Petroleum Corporation	14,779.00	.3	95.6
Inexco	12,149.00	.2	95.8
Cabot	11,105.79	.2	96.0
Champlin	10,284.00	.2	96.2
Home Petroleum	10,240.00	.2	96.4
Tenneco	10,183.00	.2	96.6
Acoma	9,033.00	.2	96.8
Mitchell Energy	8,880.00	.2	97.0
Sundance	8,880.00	.2	97.2
Clark	8,830.00	.2	97.4
Oil Development Company	8,320.00	.2	97.6
Brinkeroff	8,078.56	.2	97.8
Alaska Kenai	8,078.50	.2	98.0
Apexco	7,680.00	.2	98.2
Highland Research	7,680.00	.2	98.4
Anadarko	7,670.00	.2	98.6
Alaska Energy	7,571.56	.2	98.8
America Petrofina	7,407.00	.2	99.0
Tesoro	5,705.00	.1	99.1
AGIP	5,120.00	Nil	
Buttes	5,120.00	Nil	
Oxy Petroleum	5,120.00	Nil	
Aztec	5,120.96	Nil	
Aminoil	5,120.00	Nil	
Alaska Exploration	5,001.00	Nil	
Inlet	4,735.00	Nil	
Beel and Beel	4,735.00	Nil	
Cable Petroleum	4,335.00	Nil	
1409 Corporation	2,560.00	Nil	
Geopol	2,560.00	Nil	
Hamilton Bros. Petroleum	2,555.00	Nil	
Canus	2,501.00	Nil	
Panocean	2,501.00	Nil	
Alaska Energy	2,168.00		
	5,282,451.52		

80 members so deciles are in groups of eight

Source of raw data: Pedro Denton, D.N.R.



COMPETITIVE
TOTAL
ACREAGE

Table C-4

Ranking of Oil Companies by Competitive Net Acreage

		Individual	Cumulative	
Atlantic Richfield	401,400.02	16.8%	16.8%	
Phillips Petroleum	270,826.50	11.3	28.1	
Union	172,792.05	7.2	35.3	
Standard Oil of California	162,323.78	6.8	42.1	
Exxon	147,205.23	6.2	48.3	
Sohio	138,875.88	5.8	54.1	
Mobil	120,203.04	5.0	59.1	
Cities Service	117,681.20	4.9	64.0	10%
BP Alaska	102,674.99	4.3	68.3	
Amoco Production	97,532.62	4.1	72.4	
Texaco	63,708.10	2.7	75.1	
Continental	49,145.82	2.1	77.2	
Beard Oil	40,855.00	1.7	78.9	
Shell	37,578.64	1.3	80.2	
Marathon	31,917.69	1.1	81.3	
Texas International	26,413.05	1.1	82.4	20%
Simaski	26,356.66	1.0	83.4	
Gulf	24,546.61	1.0	84.0	
Louisiana	24,451.34	.9	84.9	
Pennzoil	22,658.00	.9	85.8	
Yates	21,168.29	.9	86.7	
Halbounty	20,508.43	.9	87.6	
Ame ada Hess	19,262.97	.8	88.4	
Newmont	13,993.39	.6	89.0	
Getty	13,778.12	.6	89.6	
Inexco	12,149.00	.5	90.1	
Cabot	11,105.79	.5	90.6	
Placid	10,737.99	.4	91.0	
Skelly	10,577.00	.4	91.4	
Gas Supply Corporation	10,531.00	.4	91.8	
Superior	9,520.05	.4	92.2	
Westcoast	9,436.50	.4	92.6	
Ulster	9,436.50	.4	93.0	
Oil Development	8,320.00	.3	93.3	
Home	8,320.00	.3	93.6	
Amarex	8,206.00	.3	93.9	
Alaska Energy Corporation	7,571.56	.3	94.2	
Anadarko Production	7,670.00	.3	94.5	
Sundance	6,786.54	.3	94.8	
Tesoro	5,705.00	.2	95.0	

(To be continued)

Table C-4 (continued)

		Individual	Cumulative
Aztec Oil	5,122.96	.2%	95.2%
Alaska Kenai	5,049.10	.2	95.4
Derby Refineries	4,787.98	.2	95.6
Apexco	4,736.00	.2	95.8
Al-Aquitaine Exploration	4,670.84	.2	96.0
Maruzen	4,329.84	.2	96.2
Ashland	3,913.36	.2	96.4
Tenneco	3,817.51	.2	96.6
Pacific Lighting	3,629.50	.2	96.8
Clark	3,031.49	.1	96.9
Inlet	2,959.20	.1	97.0
Oxy Petroleum	2,816.00	.1	97.1
Geopol	2,560.00	.1	97.2
Alaskan Exploration	2,503.50	.1	97.1
Hunt Oil	2,216.85	.1	97.4
Hamilton	2,143.88	.1	97.5
Brinkeroff Drilling	2,019.64	.1	97.6
American Petrofina	1,851.75	.1	97.7
Alaska Energy	1,734.40	.1	97.8
Ampco American	1,640.00	.1	97.9
Hunt Industries	1,589.60	.1	98.0
Transocean	1,477.90	Nil	
Champlin	1,476.00	Nil	
Acoma	1,470.60	Nil	
Hamilton Bros. III	1,429.25	Nil	
Hamilton	1,376.28	Nil	
Buttes Gas	1,280.00	Nil	
Calderwood	1,199.48	Nil	
Hunt Petroleum Corporation	1,182.32	Nil	
Mitchell	1,110.01	Nil	
AGIP	1,024.00	Nil	
Pan Ocean	937.88	Nil	
Coastal State	662.63	Nil	
Canus	625.25	Nil	
Carl Brewing	540.80	Nil	
Aminol	531.97	Nil	
Cable Investment	334.15	Nil	
1409 Corporation	256.00	Nil	
Sunlite	214.42	Nil	
Hartog	194.67	Nil	
Husky	149.61	Nil	
Arnold	105.76	Nil	

(To be continued)

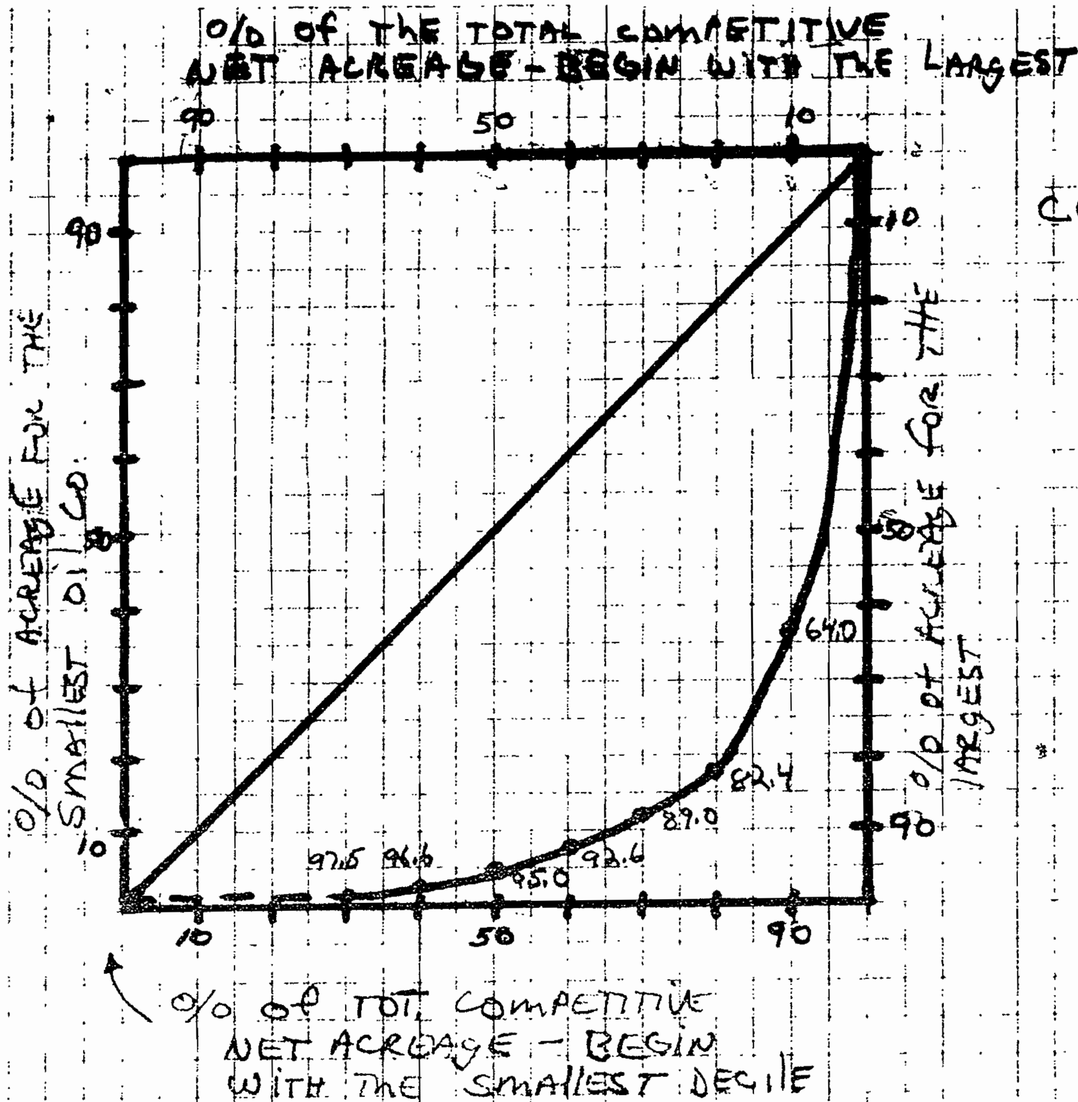
Table C-4 (continued)

		Individual	Cumulative
Beel and Beel	94.70	Nil	
Belco	70.52	Nil	
Highland Resources	45.51	Nil	
Oil Resources	21.47	Nil	
	2,389,758.33		

86 members so deciles will be in groups of eight since so many have such small percentages

Source of raw data: Pedro Denton, D.N.R.

COMPETITIVE NET ACREAGE



Appendix D

NON-COMPETITIVE ALLOCATION SYSTEMS: A CRITIQUE

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Paper prepared for Dr. Mason Gaffney
27 January 1977

1. Introduction

The United States represents the exception rather than the rule in its adoption of competitive mechanisms for allocating oil and gas rights on public lands.[1] The United Kingdom, Norway, Canada, Australia and the Middle East oil producers have all preferred non-competitive systems. These systems may be classified into two categories: filing (or "free entry") procedures and discretionary (or negotiated) systems.

2. Filing Systems

The distinguishing feature of these systems is the opportunity presented to each private operator to obtain exclusive exploration and/or production rights for oil and gas on public lands simply by lodging an application, at nominal cost. Additional obligations may also be imposed, such as location of a claim, survey of the area in question, and registration of the claim, but these are generally insignificant. What is important is that the initiative in obtaining rights rests solely with the private operator. The government has no active role in the allocation process. Examples of filing systems for oil and gas rights may be found in Canada, in the northern and offshore regions under the jurisdiction of the federal government[2], and in Alberta (until 1 July 1976).[3] Many more instances occur in the field of hard rock mining.

Problems encountered with filing systems are numerous while advantages are few. The major difficulties include (a) inefficiency (b) loss of potential government revenue, and (c) lack of control over location of oil and gas operations.

(a) Inefficiency. Filing systems promote inefficiency by providing an incentive for exploration before it is required. Each operator is aware of the fact that, in order to obtain rights over prospective acreage, he must be the first to make an application. He is therefore encouraged to apply earlier than he would in the absence of this "competitive" element. This factor in itself need not lead to inefficiency if the cost of obtaining the rights is negligible. However, a common characteristic of filing systems is the obligation imposed upon private operators to spend fixed amounts in approved exploratory work each year in order to maintain the rights in force. This requirement causes premature expenditure on exploration.

It is sometimes suggested that exploration should take place at the earliest possible date, in order to provide information about the resource. While it is true that information is useful, it must be recognized that information is obtained at a cost. A dollar spent on exploration today amounts to more than a dollar spent next year. Accordingly, premature exploration reduces the ultimate value of the resource in production.

Another argument made in favour of filing systems proceeds on the ground that the cost of any inefficiency is borne by the private operator rather than the government. Since the major companies explore in many jurisdictions other than Alaska, it is claimed that encouragement of premature exploration merely attracts dollars from other places to be spent in Alaska (with consequent benefits to the local economy). The difficulty with this approach is that it too overlooks the fact that exploration expenditures are taken into account in assessing the value of the resource. And it is that value which provides the opportunity for government revenue. In the end result, it is the government which suffers the cost of premature exploration.

Another problem with filing systems is that they do not ensure that rights are awarded to the most efficient operator. The company which is first to recognize the potential of an area need not be the one to develop it at least cost. If rights are transferable among operators without restriction (a feature usually absent from filing systems because of opposition to "speculative" gains) the most efficient operator may ultimately acquire the acreage by purchase. But this may well be a costly process which again leads to inefficiency and waste.

(b) Loss of Government Revenue. Under a filing system, a private operator has an incentive to apply for oil and gas rights in respect of an area as soon as that area takes on a positive value, however small. Thereafter, any increase in value of the area flows to the private operator rather than the government.

The discovery process for oil and gas causes frequent reappraisals of the value of areas, often upwards. A successful well drilled on one block upgrades the potential of adjoining areas. A government which allocates blocks on a restricted basis, retaining nearby areas until their potential is better known, is in a position to benefit from these information "spillovers". In contrast, a filing system allows private operators to reap these unearned rewards. An illustration is provided by the different allocation systems in force in Alaska and the Canadian north at the time of the Prudhoe Bay discovery. Alaska was in a position to sell adjoining acreage at considerable benefit to government revenue. In Canada the filing system allowed private operators to acquire prospective acreage on a first-come, first-served basis. The area under permit more than doubled (from 190 to 440 million acres) between 1968 and 1970.[4] There can be no doubt that the filing system precluded the Canadian government from vast revenues.[5]

It is not surprising that the Canadian filing system was suspended in 1970, with a view to widespread revision. However, in 1977 that process has still not been completed.[6] This illustrates another feature of filing systems: they allow private operators to acquire rights long before development may be contemplated. A change in external circumstances (such as occurred with the enormous increases in world oil prices during 1973 and 1974) may destroy the underlying assumptions upon which the rights were issued. Nevertheless, the government finds itself in a position where many of its options are foreclosed. It may be driven to new forms of taxation by an inability (or unwillingness) to revise the rights structure.

(c) Lack of Control Over Location. Since a filing system places the initiative regarding allocation of oil and gas rights squarely upon the private operator, the government has little opportunity to control the siting of exploration and production. Oil and gas operations are thereby afforded priority in situations of land use conflict. This situation is plainly inconsistent with government responsibility to take account of a wide range of social, economic and political factors, such as impact on local communities and protection of the natural environment.

The principal advantage claimed for filing systems is that the minimal role of government implies correspondingly small administrative cost. This is so, but the argument proceeds upon a highly restrictive view of cost. If account is taken of the losses of potential government revenue flowing from the above inefficiencies and inequities, it appears beyond doubt that filing systems are very expensive to the public.

Finally, it may be noted that the original proponents of filing systems, the Canadian and Albertan governments, have recently abandoned them. The proposal for changes in oil and gas rights in the Canadian northern and offshore regions adopts competitive bidding as the allocation mechanism, as does the new Alberta regime which took effect on July 1, 1976.

3. Discretionary Systems

Characteristic of discretionary or negotiated systems is the fact that the administrator is placed in a position of choosing among applicants for oil and gas rights in specified areas. The government retains a very high measure of control over private operators: it nominates the areas available for acquisition, determines the time at which such areas become available, selects the operator for each area, and (usually) lays down the terms and conditions upon which rights are acquired. In the result, there are often considerable variations in rights among operators in different areas. Examples of discretionary systems are found in Norway[7], the United Kingdom[8], Australia[9], and most OPEC countries.

Disadvantages inherent in these systems are (a) the potential for graft, (b) inefficiency, (c) administrative difficulties and (d) loss of government revenue.

(a) Graft. It is unnecessary to say much about the opportunity for graft and corruption presented by a system which vests wide descretion in a public official to deal with resources of considerable value. It is not suggested that this has been a failure of the Norwegian, United Kingdom or Australian systems. However, the potential must be recognized and, if such a system is adopted, an appropriate review mechanism included to take account of this factor.

(b) Inefficiency. The inefficiency arising under discretionary systems is derived from the fact that the private operator selected for each area is not necessarily the least cost operator. Of course, this result is to a degree intentional: it simply represents the price paid for the opportunity to implement government policy. The difficulty lies in quantifying that price. In the absence of a bidding procedure, the government is unable to ascertain how much potential revenue it is forgoing in order to promote its chosen policies.

(c) Administrative Difficulties. This factor is closely related to the previous one. The administrator is placed in a position where he must choose among applicants. On what basis should the choice be made? Undoubtedly the legislature may specify guidelines or criteria. Inevitably, though, the administrator will require considerable information regarding the geology of the area, exploration and production costs, marketing and pricing factors (to name but a few) in order to apply those guidelines. The difficulty is compounded by the fact that the only source of such information is likely to be the companies themselves. Perhaps it is not surprising, therefore, that some countries which rely upon discretionary allocation have opted for creation of a government corporation to participate in all phases of exploration, development and production, not just as a means of obtaining revenue but also to provide the information necessary to administer the system. The United Kingdom and Norway illustrate this trend.

(d) Loss of Government Revenue. Unless the government is confident that it can design a production tax which is entirely successful in taking account of differing geological, cost and location factors among fields (all of which influence the ultimate value of production), discretionary systems involve a loss in government revenue. This loss may indeed be large. In 1971 the United Kingdom experimented with bonus bidding for 15 blocks in the North Sea. The revenue obtained, more than 37 million pounds, became a source of government embarassment as people were not slow to calculate how much potential revenue may have been lost on the 848 blocks previously issued "free" by the discretionary method.[10]

Advantages claimed for discretionary systems flow from the control retained by government. The allocation process may be manipulated to achieve policy objectives, such as preference for domestic operators (apparent in the U.K. system) and priority for small rather than large corporations. The only response to be made to this claim is to inquire, at what cost?

Supporters of discretionary allocation also point out that it avoids "front-end load" - the commitment of substantial capital sums by private operators long before production (and cash flow) begins. However, it is not the only method for dealing with this problem. A competitive allocation system may be designed where cash bonuses are intentionally small because the system also employs production-based taxes or charges designed to collect the greater part of government revenue.

Finally, there is no doubt that discretionary allocation, if combined with negotiated work commitments, may provide a means of subsidising exploration. The problem lies in deciding whether, accepting that a subsidy has been judged to be desirable, this method represents the most efficient form of subsidy. This is unlikely to be the case. The cost to government revenue is unascertained, so that the success of the programme is difficult to evaluate. Moreover, it has been shown that if a government is prepared to give up cash bonuses in order to stimulate exploration, work commitment bidding will generate greater exploration expenditure.[11]

4. Conclusion

In summary, it is suggested that competitive allocation of oil and gas rights over public lands has considerable advantages over non-competitive mechanisms, on both efficiency and equity grounds. Competitive allocation need not be inconsistent with other government objectives, such as avoidance of front-end load. Part of the strength of a competitive system is derived from the fact that it places reliance upon private operators to evaluate different areas (although government should not be precluded from calculating reserve bids, which implies that government obtain the information necessary for this task). Moreover, competitive allocation may be the only way (short of *ex post* assessment) of taking account of all factors which determine the value of areas. When used in combination with other taxes and charges, bidding provides a measure of the effectiveness of the entire revenue system. When the level of bids uniformly rises, the government receives a signal that revision of future taxation arrangements may be necessary (the converse also holds). Lastly, and perhaps most significantly, competitive allocation adds a measure of political acceptability (and thereby stability) to a system designed for public resources.

Footnotes

1. Competitive mechanisms are not exclusively employed in the U.S., of course; the Mineral Leasing Act of 1920 provides for non-competitive allocation outside a "known geologic structure of a producing oil or gas field."

2. Canada Oil and Gas Land Regulations, Statutory Orders and Regulations 61 - 252 (as amended). A detailed description (and critique) of this system is to be found in Michael Crommelin, "Offshore Oil and Gas Rights: A Comparative Study", 14 Natural Resources Journal 457 - 500 (1974).

3. For a review of the Alberta allocation process as it operated until July 1, 1976, see Michael Crommelin, "Government Management of Oil and Gas in Alberta", 13 Alberta Law Review 146 - 211 (1975).

4. Canada, Department of Indian Affairs and Northern Development, Activities 1970: Oil and Gas North of 60 (Ottawa, 1971).

5. See Crommelin, "Offshore Oil and Gas Rights", 474.

6. In May 1976 the federal government issued a Statement of Policy giving details of the proposed new leasing system. The legislation to implement the widespread changes has not yet appeared. (January 1977)

7. For an account of the Norwegian system, see Kenneth Dam, "The Evolution of North Sea Licensing Policy in Britain and Norway", 17 Journal of Law and Economics 213 - 263 (1974).

8. See Dam, "North Sea Licensing Policy", and Crommelin, "Offshore Oil and Gas Rights".

9. See Crommelin, "Offshore Oil and Gas Rights".

10. Crommelin, "Offshore Oil and Gas Rights", 470.

11. Gregg K. Erickson, "Work Commitment Bidding", in Crommelin and Thompson (eds.), Mineral Leasing as an Instrument of Public Policy (Vancouver: University of British Columbia Press, 1977 forthcoming).

Appendix E

UNCERTAINTY, COMPETITION, AND LEASING POLICY

by

Richard B. Norgaard

UNCERTAINTY, COMPETITION, AND LEASING POLICY

by

Richard B. Norgaard*

In a world of certainty and competition--of known resources, known production costs, known future prices, and many competing firms--the optimal resource transfer policy would be to sell development rights everywhere simultaneously on a simple lump-sum basis to the highest bidders. On the other hand, when there is considerable uncertainty, all at once, fee-simple sales will be suboptimal. Farmland, for example, is almost always sold on a lump-sum basis for the quantity and quality of the land can be readily assessed, the costs of farming are quite well known, futures markets are available to stabilize income received by farmers, and there are many buyers and sellers of farmland. Book publication rights are an example of the opposite extreme; the demand for a book is difficult to predict, average production costs decrease substantially with volume, and most authors are quite fortunate to have more than one seriously interested publisher. Due to the uncertainty at the time the sale must occur, most publication rights are transferred in exchange for a royalty--a share of the gross revenues.

Petroleum development rights are currently transferred using a mixed strategy, a combination of lump-sum (bonus bid) payments and royalties. This paper investigates how uncertainty and competition theoretically relate to optimal leasing policy in section I; reviews game theoretic bidding models in section II; analyzes leasing performance for offshore Cook Inlet, Alaska, in section III; and

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presents general conclusions in section IV. Overall, this paper is concerned with whether the current mixed strategy is mixed appropriately.

I. Uncertainty and Leasing Policy[1/]

In this section we will assume that the assumptions of the competitive economic model hold, particularly with respect to the number of buyers and sellers, except that uncertainty will be introduced. To begin, however, it is appropriate to review why the competitive model under conditions of certainty leads to the conclusion that the optimal petroleum leasing policy is to lease all tracts strictly on a lump-sum (bonus) bidding basis. Under these conditions, the most efficient firms--the ones with the lowest production costs--would win the lease since they will be able to bid the most. The state would collect all the rent since competition between firms would eliminate excess profits. Lastly, theoretical studies indicate that, under conditions of uncertainty, competitive industry will optimally exploit a finite resource over time.[2/]

A royalty would be an undesirable means for the state to collect rent since it decreases revenues on the margin and thereby reduces the incentive to explore, drill wells, and bear extraction costs. These distortions lead to lower production levels and lower government revenues. Thus, under certainty, the optimal policy is to lease all tracts to the highest bonus bidder, with no other forms of payments required.

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1/ Discussion similar to this section but applied to federal OCS leasing can be found in Hayne E. Leland and Richard B. Norgaard with Scott R. Pearson, "An Economic Analysis of Alternative Outer Continental Shelf Petroleum Leasing Policies," Prepared for the Office of Energy R&D Policy, National Science Foundation, September, 1974.

2/ Robert M. Solow, "The Economics of Resources or the Resources of Economics," American Economic Review, Vol. LXIV, No. 2 (May, 1974), pp. 1-14. The theoretical model assumes that the rate of interest is appropriately determined in perfect capital markets. To the extent that this is not true, the conclusions reached in these analyses will be incorrect.

But petroleum development is not risk free, especially in frontier areas such as Alaska. There is uncertainty about the amount of petroleum that will be found. Section III of this report indicates that this risk has been substantial. The costs of exploration, production, and transport to market vary greatly in Alaska and are largely unknown to potential lessees at the time of a sale. And future petroleum prices are highly uncertain due to OPEC's instability and changes in the pace of resource discovery and technological breakthroughs. For a variety of reasons—changing social values, increased awareness of environmental complexity, and skepticism of new technology—these uncertainties seem to be greater than they have been in the past.

Relative to the risk-free optimal leasing policy, uncertainty introduces exploration, sale sequencing, and risk sharing into leasing strategy. To the extent that petroleum firms, or at least many firms, operating in or potentially operating in Alaska are more risk averse or less able to diversify risk than Alaskans as a whole, the firms tend to discount future net revenues too much. Excessive discounting leads to suboptimal exploration and development, lower levels of production, and consequently to lower bonus bids. Further, uncertainty makes it difficult for firms to raise capital. Small firms with fewer opportunities to spread risk may be at a disadvantage to larger firms. Unequal competition is less competition which further reduces the likelihood that the government will collect its fair share.

Exploration, especially with the drill bit, reduces uncertainty. More exploration prior to lease sales could substantially increase government revenues. Of course, for those areas for which additional early exploration results in a lowering of expectations of petroleum potential, bonus bid revenues would decrease sharply. Indeed, with additional exploration prior to sales, more areas would logically remain unleased than with the current timing of exploration.

On the other hand, where earlier exploration results in increased expectations of petroleum, bonus bid revenues would increase. To the extent that many firms are more risk averse and/or less able to diversify risk than Alaskans as a whole and/or to the extent that the current approach to exploration is inefficient due to information externalities, bonus bid revenues to the state will increase on the average. The analysis developed in section III indicates that, if exploration with the drill bit increased the effectiveness of the bonus bid from 16 percent to 80 percent as a means of collecting rent on offshore Cook Inlet sales through 1968, then lease bonus bids would have increased overall by a factor of five. The increased revenues to the state would have been equivalent to nearly $300 million (in 1975 dollars) received in 1961.1/ Since most if not all state-initiated exploration with the drill bit prior to lease sales would have been undertaken by industry eventually anyway, the $300 million represents a net gain. Many will argue that government-initiated exploration is inefficient. Perhaps so, but from the point of view of revenues to the state, it appears that considerable inefficiency would be tolerable.

RECOMMENDATION I.A. <u>The Department of Natural Resources should initiate the drilling of some of the more uncertain structures, especially in new areas, and publicly disseminate the information collected prior to lease sales.</u>

The state would be better able to plan petroleum lease sales over time if it had better information on resource potential in the various petroleum areas.

1/ Using a 10 percent discount rate, the 1961 present value in 1975 dollars of bonus bids received from offshore Cook Inlet tracts was $73.8 million. The 16 percent effectiveness rate is derived in section III. Raising the effectiveness rate to 80 percent would increase the revenues by an additional factor of 4, or an additional $295.2 million. This estimate is subject to all of the assumptions specified in section III but nevertheless is an appropriate illustration of how earlier exploration could increase revenues.

The wellhead value of Alaskan oil may be fairly sensitive to the level of production due to limited pipeline capacities within the state, limited demand on the West Coast, and limited pipeline capacities to the Midwest. Unless Alaskan oil can be exported to Japan, there will be significant advantages to coordinating petroleum development with transportation development and demand. With better information, lease sale revenues to the state could be better predicted or sales better scheduled to meet state revenue needs. The timing of lease sales with different expected petroleum potential is the best mechanism for scheduling production and revenues. Production prorationing, such as occurred extensively in Texas, Oklahoma, and Louisiana during the late 1950's, is a poor mechanism since capital (each well) is used inefficiently. Such inefficiencies in the long run reduce the rent collected by the state. Currently, however, the state is not systematically collecting information on the resource potential of petroleum provinces for the purpose of scheduling lease sales.

RECOMMENDATION I.B. The Department of Natural Resources should share with industry the expense of collecting geological and geophysical information and develop its own capability or contract for the interpretation of seismic and other data in order to better assess petroleum potential for the purpose of improving the scheduling of lease sales.

Petroleum development risks can be shared between government and industry in many ways--royalties, oil pledges, annual rental payments, and profit sharing are the more commonly considered means. Because risk is shared in these approaches, the negative effects stemming from risk aversion--excessive discounting of future revenues and lower levels of competition--are abated. Since annual revenues are related to production (or cumulative acreage or estimated value of acreage under lease), the revenues are more evenly distributed over time than when more reliance is placed on the bonus bid. This is advantageous if the state perceives a lower rate of discount as appropriate and/or is reluctant to rely on capital markets to even out the flow of bonus bid revenues. Differences in the various schemes for sharing risk are developed fully in the main text of this report and, hence, further elaboration is unnecessary here.

II. Game Theory and Leasing Policy

The market economy model is the predominant framework used in western societies for thinking through issues involving resources (property), production, and exchange. With or without a formal course in economics, most people currently understand and accept the concept of competitively determined market prices. The theory of supply and demand, barely two centuries since its infancy, is deeply embedded in the slogans of businessmen, the logic of newspaper editorialists, and the rhetoric of legislators. Because the basically simple, yet expandable and adaptable, market model is widely accepted, both debate over economic issues and public decision making are vastly simplified.

However, there are other models or frameworks for devising individual strategies and for analyzing economic behavior. Game theory is such a model with special importance to leasing policy. In the competitive model, certainty and competition are assumed. Game theory, on the other hand, assumes uncertainty and a limited number of competitors. The objective of this section is to describe the differences between the models and their implications for leasing policy. Alaska will not collect its fair share of the rent if it presumes the competitive market model is operational while industry plays a different game.

With respect to petroleum development right bidding, the two models differ as follows. In the competitive model the petroleum potential is known, and there are many bidders. Each bidder realizes that he will only be able to win the lease and thereafter cover all costs if he is the most efficient operator. Since efficiency of operation is the only variable the entrepreneur can affect, all entrepreneurial talents are directed at efficiency. Competitive bidding with reasonable certainty does take place in some areas of construction and light manufacturing, and in these industries efficiency indeed makes the critical difference between success and failure.

Efficiency never hurts a firm which faces limited competition in an uncertain situation. But under these circumstances, there are additional or alternative outlets for entrepreneurial talent. The objective is still profit maximization, but now the bidder logically asks: "What is the tradeoff between reducing the bid and reducing the probability of winning; what is the optimum reduction from the tract's expected value for profit maximization?" Game theoretic models provide an analytical framework for answering this question. The petroleum industry managers have undoubtedly asked and pursued the question intuitively since the industry's beginnings. Formal models have been employed, at least experimentally, since at least 1962.[1/]

The model by Capen et al. is fairly representative and is presented here to illustrate the factors formally considered.

Let

$f_i(x)$ = the probability density function for the *i*th opponents' bid;

and let

$F_i(X)$ = the probability that the *i*th opponent bids a value less than x.

With n opponents,

$\prod_{i=1}^{n} F_i(X)$ = the probability that n independent opponents all bid a value less than x.

Now let

$g(x)$ = the probability density function for our bid.

1/ E. C. Capen, R. V. Clapp, and W. M. Campbell, "Competitive Bidding in High-Risk Situations," Journal of Petroleum Technology (June, 1971), pp. 641-653.

Define

$$h(x) = K_n \left[\prod_{i=1}^{n} F(X) \right] g(x)$$ = the probability density function for our winning bid where K_n is a constant to make the integral of that density equal 1.

Then the expected value of our winning bid, $E(X_w)$ is:

$$E(X_w) = \int_{-\infty}^{\infty} xh(x)\, dx$$

$$= \int_{-\infty}^{\infty} xK_n \left[\prod_{i=1}^{n} F_i(X) \right] g(x)\, dx.$$

The objective then is to maximize this expected value. The bidding strategist clearly becomes concerned with two phenomena--the number of opponents, n, and the probability density function of the opponents' bids. Capen et al. assume that the opponents' bids are independent and their probability density functions (quality of information about tract value) are the same. Alternative assumptions about the underlying density functions have been utilized; log normal is frequently rationalized.1/ Except in the simplest examples, solutions are derived through simulation techniques rather than analytically.

Other researchers have simulated optimal strategies when all bidders are pursuing optimal strategies and investigated strategies where the bidder expects he has superior or inferior information relative to his competition.2/ It is

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1/ Paul B. Crawford, "Texas Offshore Bidding Patterns," Journal of Petroleum Technology, March, 1970, pp. 283-289. Also, Chester Pelto, "The Statistical Structure of Bidding for Oil and Mineral Rights," Journal of the American Statistical Association, Vol. 66, No. 33 (September, 1971), pp. 456-460. Capen et al. also provide a simple argument for the log-normal distribution.

2/ C. D. Zinn, W. G. Lesso, and G. R. Givens, "OILSIM--A Simulation Model for Evaluation of Alternative Bidding Procedures," Paper presented at the 96th Winter Annual Meeting, American Society of Mechanical Engineers, November 30-December 5, 1975, Houston, Texas; and E. L. Dougherty and M. Nozaki, "Determining Optimum Bid Fraction," Journal of Petroleum Technology, March, 1975, pp. 319-356.

interesting to note that, while a significant portion of the growing literature on bidding for petroleum rights on public lands has been contributed by university researchers, almost none of the papers take a public perspective.[1/] A forthcoming Ph.D. dissertation by Douglas K. Reece incorporates a superior game theoretic model and specifically simulates what happens to the government's share of the rent as the number of bidders increases and the quality of information improves under lease bonus, royalty, and profit share bidding schemes. Completion of this dissertation is expected by June, 1977.[2/]

In summary, under conditions of certainty and a large number of bidders, the state of Alaska could expect to receive all of the rent from the petroleum resource. Game theory indicates bidding strategies whereby firms can maximize the rent they receive from the petroleum resource when there is uncertainty and few bidders. Game theoretic models indicate that the magnitude of the winning bid and, hence, the share of the rent received by the government increases with increasing certainty and more bidders. These general conclusions support the argument for more publicly initiated exploration and for the state of Alaska to establish bid-rejection criteria which, at least, have the effect of increasing competition and perhaps are established to counter game theory derived industry-bidding strategies.

RECOMMENDATION II.A. The Department of Natural Resources should establish bid rejection criteria based on the expected value of

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1/ Leading universities are Southern Methodist University, University of Southern California, and the University of Texas. An article by David Hughart of the University of Michigan is an exception to the above generalization. See David Hughart, "Informational Asymmetry, Bidding Strategies, and the Market of Offshore Petroleum Leases," Journal of Political Economy, Vol. 83, No. 5 (1975), pp. 969-985.

2/ Douglas K. Reece, "Leasing Offshore Oil: An Analysis of Alternative Bidding Systems." Applied Economics Division, Graduate School of Business Administration, University of California, Berkeley, June, 1977.

petroleum in order to effectively increase the level of competition by one bidder.

RECOMMENDATION II.B. The Department of Natural Resources should employ an expert in game theory as a part of its permanent staff to explore the implications of alternative game theory models, levels of information, and leasing strategies from the state's perspective and to assist in the development of bid rejection criteria for particular lease sales. Given the theoretical nature of this staff position, a joint appointment with the University of Alaska, Anchorage, may prove attractive.

III. Analysis of Offshore Cook Inlet Lease Sales

The lease sales of offshore Cook Inlet tracts are analyzed in this section in the context of the problems raised by uncertainty and game theoretic bidding strategies developed earlier. This area was selected because there have been a fairly large number of sales and tracts leased, there is a history of production, and per barrel production costs are probably more representative of other Alaskan petroleum provinces than, for example, Prudhoe Bay. The level of competition, bidding patterns, and lease ownership are considered in Part A. An estimate of the share of the rent captured by the state, the effectiveness of the lease bonus bid in capturing rent, and possible explanations of this effectiveness are developed in Part B.

The analysis draws upon leasing data kept by the Division of Lands, production data kept by the Division of Oil and Gas, and production decline rates estimated by John Miller of the Division of Oil and Gas. John Baxandall of the Division of Oil and Gas supervised the data processing and derivations of key statistics. The initial data came from diverse sources which had never been brought together in a single analysis before. Each of the initial data sets had some errors, and additional small errors have undoubtedly been made in the process of combining the sets. Time has been insufficient during the period of this study to correct all of the possible small errors. No errors or combination of errors have been come upon to date, however, which would change the general conclusions of the analysis.

> RECOMMENDATION III.A.1. The Department of Natural Resources should allocate more resources to data management and to processing capability to improve the accessibility and reliability of information needed for ongoing management decisions and occasional in-depth analyses.

A. Competition, Bidding Patterns, and Lease Ownership

The level of competition and average lease bonus bids for offshore Cook Inlet sales through 1968 are presented in Table 1. The average number of bidders per tract in these sales ranges from one to four, with the vast majority of the sales averaging between two and three bidders per tract. These averages are not impressively high. The average number of bidders, for example, for federal OCS sales in the Gulf of Mexico in the early 1960's ranged between three and four, nearly 50 percent higher.1/ Column 8 of Table 1 indicates the percentage of tracts leased, with only one bidder. For the sales with a significant number of tracts, this ranges from 11 percent to 36 percent, with an overall average of 25 percent. For the federal sales cited above, 37 percent of the tracts leased received only one bid. Column 9 of Table 1 indicates the percentage of tracts with four or more bidders. For the larger Cook Inlet sales, this ranges between 26 percent and 51 percent, with an overall average of 33 percent. For the federal sales cited above, 41 percent of the tracts leased had four or more bidders. These two columns in Table 1 together illustrate the wide range in the interest in bidding on individual tracts in each lease sale and across lease sales.

Merely looking at the number of bidders, however, is insufficient. In the Cook Inlet sales, at least one of the bids on a significant number of the tracts has been placed by an individual or group of individuals. These bidders have poorer access to geologic and seismic data and, when a tract is won, are unlikely to be able to acquire sufficient capital or expertise to explore for and develop

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1/ The lease sales dated February 24, 1960, and March 13 and 15, 1962, are used for comparison because a bidding and production analysis similar to that developed in this report is available: John Lohrenz and Hillary A Oden, "Bidding and Production Relationships for Federal OCS Leases: Statistical Studies of Wildcat Leases, Gulf of Mexico, 1962, and Prior Sales," Paper prepared for the 48th Annual Fall Meeting of the Society of Petroleum Engineers of AIME, September 30-October 3, 1973, Las Vegas, Nevada, Paper Number SPE 4498.

TABLE 1

Lease sale number	Date	Acreage leased	Number of tracts	Total bonus bid received	Bonus bid per acre	Average number of bidders on each tract	Percent of tracts with only one bidder	Percent of tracts with four or more bidders
1	2	3	4	5	6	7	8	9
				1975 dollars			percent	
1	December, 1959	25,621	11	5,491,775	214.35	2.4	36	27
2	July, 1960	8,435	5	126,702	15.03	1.6	60	0
3	December, 1960	1,852	1	18,464	9.96	1.0	100	0
7	December, 1961	146,126	33	26,687,220	183.10	2.5	36	30
9	July, 1962	264,437	74	28,830,474	109.00	2.8	23	28
10	May, 1963	75,669	35	1,960,480	25.93	3.0	11	29
12	December, 1963	184,248	135	4,858,631	26.37	2.8	22	27
13	December, 1964	149,089	86	1,951,697	13.09	2.8	27	26
15	September, 1965	287,383	187	8,299,350	28.88	2.9	33	34
16	July, 1966	76,394	65	2,174,137	28.46	4.0	22	51
19	March, 1967	2,560	1	4,521	1.77	1.0	100	0
20	July, 1967	175,836	85	31,685,321	180.19	4.0	14	47
22	October, 1968	895	1	10,266	11.47	2.0	0	0

petroleum. They typically bid a small fixed amount per acre--$1.00, $1.01, and $1.10 have proven popular--on a large number of tracts. These "fishing bids" significantly increase the apparent average number of bids per tract but provide little competition to the more knowledgeable industry bidders on tracts more likely to be valuable. For example, in lease sale 9 there were a total of 207 bids submitted on 74 tracts leased, an average of 2.8 per tract. But 101 bids of $2.25 per acre or less were submitted, and 25 tracts were leased with these low bids. If we subtract both the low bids and the less valuable tracts won with low bids from the total, then 106 serious bids were submitted on 49 tracts. The average number of bidders per tract falls from 2.8 overall to 2.2 serious bidders on the more likely tracts.

The sum of the lease bonus bids on the 25 tracts in lease sale 9 won with fishing bids came to $100,000 or only 0.6 percent of the total in bonus bids received in this sale. Only one tract won with a fishing bid (Pan American Oil, ADL tract #17579) has ever produced a significant amount of oil. This tract's share of the total discounted value of oil produced and expected to be produced from tracts ever in production to date come to a mere 1.5 percent. The higher level of apparent industry interest in the federal sales cited above has typically been attributed to the remoteness of and special technologies needed in Alaska. It appears, however, that a large portion of the difference may also be due to more intense screening of industry nominations of tracts to be leased or better selection by the U. S. Geological Survey of sites with petroleum potential. In the federal sales cited above, between 15 percent and 30 percent of the tracts became productive, whereas only 2 percent of the offshore Cook Inlet tracts leased through 1968 have thus far produced a significant amount of oil.

RECOMMENDATION III.A.2. The Department of Natural Resources should initiate an analysis of the tract nomination and selection process; the role of nonindustry bidders and low dollar bids on the level of competition; and the administrative, environmental, and resource development delay costs of leasing petroleum development rights on highly unlikely tracts and/or to bidders incapable of undertaking exploration and development.

The average bonus bid per acre for each lease sale is presented in column 6 of Table 1. The average bonus bid per acre in 1975 dollars ranges between $13 and $214 for the significant lease sales. This compares with an average of $786 for the Gulf of Mexico sales in the early 1960's. The difference between Gulf of Mexico and Cook Inlet bids is usually attributed to the differences in development and transportation costs. More significant, perhaps, is the difference in the tract selection criteria used by the federal and state administrations.

Pan American, Richfield (now combined with Atlantic and called ARCO) and Union have had the greatest influence on offshore Cook Inlet sales. Lease sales 7 and 9 transferred the only tracts that are currently producing or have historically produced oil. In these two sales, these three companies--the latter two bidding jointly with six other large oil companies--acquired 58 of the 107 tracts leased and spent almost $28 million of the $30 million collected in bonus bids (Table 2). These three consortia acquired 13 of the 17 tracts which later proved productive. Atlantic acquired three of the remaining four productive tracts but has since joined with Richfield.

The distribution of lease holdings among companies on the federal OCS in the Gulf of Mexico is comparable. There, 10 companies held 62 percent of the acreage in 1972.[1/] But in Alaska, 9 of the 10 companies formed 3 consortia,

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1/ U. S. Senate Committee on the Judiciary, Subcommittee on Antitrust and Monopoly, Testimony of Dr. John W. Wilson, Chief, Division of Economic Studies, Federal Power Commission, Washington, D. C., June 27, 1973.

TABLE 2

	Lease sale No. 7		Lease sale No. 9		Lease sales Nos. 7 and 9	
	Number of tracts won	Bonus bid paid	Number of tracts won	Bonus bid paid	Number of tracts won	Bonus bid paid
		thousand dollars		thousand dollars		thousand dollars
Richfield bidding with Socal, Shell, Sinclair, or Phillips	8	5,671	13	7,715	21	13,386
Pan American	13	7,296	13	3,338	26	10,634
Union bidding with Ohio or Socony Mobil	3	165	8	3,624	11	3,789
Total for three groups	24	13,132	34	14,677	58	27,809
Total for sale(s)	33	14,411	74	15,626	107	30,037

whereas in the Gulf of Mexico, almost all of the companies joint bid with each other at sometime or another. An analysis of bidding in these sales does show competition between the consortia on those tracts which were most attractive, some of which later became productive. Nevertheless, if one is not aware of the consortia, there appears to have been more companies competing and more participation in presale exploration and bid formulation than there, in fact, was. The consortia specified in Table 2 broke up somewhat in later offshore Cook Inlet sales. Independent bids appear to have been submitted by Shell and Socal, for example. And new names, notably Texaco and Marathon, appear among the more aggressive bidders in the later sales.

In the economist's model of perfect competition, there are many well-informed participants bidding prices up or withholding goods from sale until an equilibrium market price is reached. Doubt has thus far been cast on the assumption that there have, in fact, been many bidders. Lack of knowledge is also apparent from an analysis of bidding patterns. Column 10 of Table 3 presents the ratio of the difference between the first two bids divided by the sum of the first two bids. With competition and perfect information, this ratio should be very close to zero, while the greatest it could even possibly be is one. The ratio when a large number of randomly drawn numbers are compared tends toward an average of 0.5. This ratio for Lease Sales 7 and 9 averages 0.32.

With perfect information and many bidders, the winning bid should equal the discounted value of the oil less production costs and royalties. Given that royalties are proportional to value and production costs stay within a fairly well-defined range for Cook Inlet, one would expect if information prior to the lease sale was "pretty good" that the ratio of the discounted value of

TABLE 3

ADL tract number	Name of highest bidder	Name of second highest bidder	Total number of bidders	Bonus bid	Bonus bid per acre	Discounted value of: Oil production	Oil production per acre	Oil/bonus bid	$\frac{B_1 - B_2}{B_1 + B_2}$
1	2	3	4	5	6	7	8	9	10
				thousand 1975 dollars	1975 dollars	thousand 1975 dollars	1975 dollars		
17579	Pan American	None	1	20	4	18,340	3,582	904.7	1.00
17586	Pan American	British American	5	1,422	463	14,510	4,746	10.3	0.78
17587	Pan American	Gulf	3	1,202	464	3,813	1,471	3.2	0.90
17594	Union and Ohio	Pan American	2	237	46	24,398	4,769	102.9	0.42
17595	Pan American	Richfield, Shell, and Socal	5	4,730	926	42,507	8,325	9.0	0.40
17597	Superior	Union and Ohio	4	721	141	22,292	4,354	30.9	0.20
	Lease sale No. 7—other		2.3	18,355	153	0	0	0	0.31
	Lease sale No. 7—total		2.5	26,687	183	125,920	864	4.7	0.36
18729	Union and Ohio	Lloyd Powers	2	142	46	221,812	71,906	1,566.6	0.91
18730	Union and Ohio	Atlantic	5	96	25	315,264	82,140	3,297.5	0.43
18731	Union and Ohio	Atlantic	5	4,062	1,058	117,888	30,733	29.1	0.70
18742	Pan American	Socony Mobil, British American	3	971	192	74,888	14,788	77.1	0.12
18746	Pan American	None	1	62	20	43,296	13,527	694.4	1.00
18754	Richfield, Shell, and Socal	Pan American	5	5,566	1,486	75,242	20,086	13.5	0.07
18756	Richfield, Shell, and Socal	Pan American	4	953	186	110,387	21,558	115.8	0.00
18761	Union and Socony Mobil	Richfield, Shell, and Socal	4	1,122	220	84,019	16,508	74.9	0.77
18772	Atlantic	Pan American	4	110	29	48,768	12,704	445.1	0.21
18776	Atlantic	Union and Ohio	5	244	190	12,753	9,963	52.4	0.89
18777	Atlantic	Union and Ohio	4	90	48	75,909	39,908	839.7	0.36
	Lease sale No. 9—other		2.6	15,413	69	0	0	0	0.32
	Lease sale No. 9—total		2.8	28,830	109	1,180,226	4,464	41.0	0.30

Note: Column 7 presents an estimate of the discounted value of oil production at the time of the lease sale expressed in 1975 dollars. This estimate was derived as follows. The quantity of oil produced from the tract each year to 1975 was valued at the average wellhead price for that year and converted to 1975 dollars using the wholesale price index. Production in 1976 and later years was estimated from 1975 production and decline rates derived for each tract by John Miller of the Division of Oil and Gas. For 1976 and later years, real prices were forecast to rise at 5 percent per year. The estimated historic and projected future values of oil production were discounted back to the lease sale year using a 10 percent discount rate and then aggregated.

the oil to bonus paid on a tract would be positive and reasonably constant. Column 9 of Table 3 illustrates that this ratio varies from 0 on the numerous unproductive tracts to 3,298 in the case of ADL tract #18730 leased in Sale 9. Seismic exploration obviously produces very imperfect information. No one questions that there is uncertainty. The point of these two paragraphs is to show how tremendously large the uncertainty really is.

As suggested in the previous paragraph, one would expect there to be a strong positive correlation between the discounted value of the oil and the bonus bid offered under conditions of certainty or perfect information. Using the respective values for these variables from Lease Sales 7 and 9, shown in Table 3, the sample correlation between the discounted value of the oil and the bonus bid is slightly negative, -0.065. Other researchers have shown a strong correlation between the number of bidders and the bonus bid. For Lease Sales 7 and 9, the simple correlation between these two variables is indeed large and positive, 0.563.

Given both the low level of competition and the uncertainty, bidding games are played. There are numerous examples of an individual or company establishing a simple bidding pattern, for example, $1.00 per acre or perhaps $2,500 per tract, and another individual or company learning this pattern from previous sales and bidding $1.01 per acre or $2,501 per tract and winning the lease. Close bids hardly indicate competition when the numbers used are so obviously unrelated to an expected quantity of oil in place. On one tract, ADL #18729, Union 76 bid $76,760 and won. Table 3, column 7, indicates that the estimated discounted value of the oil on this tract in 1975 dollars, at the time of the lease sale, was $222 million.

A model was hypothesized to describe the relationship between bonus bid (B) and two "explanatory" variables, the discounted value of the oil (DVO) and number of bidders (N) as follows:

$$B = \alpha DVO^{\beta_1} N^{\beta_2}.$$

The value of α was expected to be a small fraction. The value of β_1 was expected to be between 0.5 and 0.8. β_2 was expected to be positive, but it was unclear whether to expect it to be greater or less than one. Lease Sales 7 and 9 data were fitted to this relationship by linear regression analysis after taking the logarithms of both sides of the equation. The estimated relationship is:

$$B = 0.043\ DVO^{0.58}\ N^{1.96}.$$

The R^2 (multiple correlation coefficient) is 0.72 and β_1 and β_2 are significantly different from zero at the 95 percent, or better, confidence level. The statistical significance of α is much less certain which further emphasizes the underlying high uncertainty in seismic exploration information.

The estimated relationship indicates that, even when account is taken of the value of the oil discovered after the fact, the bonus bid is highly sensitive to the number of bidders. The analysis indicates, for example, that, when the number of bidders increases from three to four, the bonus bid increases by approximately 16/9 or by an additional 78 percent. This undoubtedly overstates the sensitivity of the bid to the number of bidders since the actual oil produced is used in the estimation of the relationship rather than the industry's prior expectation of oil at the time bids must be formulated.

The parameter α is understandably small since the firm must reduce its bid from the value it would be if oil was there (as was the case for the productive tracts used to estimate the relationship) by the probability that oil, in fact, will be found. It is curious, however, that β_1 is considerably less than rather than equal to one. This suggests that potential large fields are discounted more than potential smaller fields. Perhaps, risk aversity and/or capital constraints prevent firms from bidding the price of the few potentially highly valuable tracts up to their full market value. This possible relationship is consistent with the author's research on federal OCS leases where it appears that those companies which place a few large bids on the most likely tracts generally earn higher returns than those companies which place more but smaller bids on less likely tracts.

In summary, the data illustrate the tremendous variations between bonuses bid and subsequent petroleum production. The simple correlation coefficient between these two variables even turned out to be negative. There is also substantial variation between the winning and next highest bid, variation closer to randomness than to order. These phenomena are undoubtedly due to a combination of high uncertainty, risk-averse behavior, capital constraints, and bidding games. Regardless of which of these explanations or combinations of explanations is most important, the bonus bid appears to be an ineffective method, or at least highly erratic method for the state to collect petroleum rents. This will be considered in further detail in Part B.

B. Bonus Bids and Rent Collected by the State

It is now well known to Alaskans that approximately 90 percent of the Prudhoe Bay field was acquired by ARCO and British Petroleum in mid-1960's sales which, along with considerable other Arctic Slope acreage, brought $10,500,000 in bonus bids. After oil was discovered, the small amount of remaining Prudhoe Bay acreage brought $900 million in bonus bids. Clearly, had the state known about the Prudhoe Bay field in advance, between \$5 billion and \$10 billion more would have been collected in bonus bids. Several years after the sale, petroleum prices tripled. Presuming that industry had not predicted this increase at the time of the sale, then the state probably "lost out" on perhaps an additional \$15 billion to \$30 billion. Prudhoe Bay is clearly a "tough luck" story for the state, and industry is quick to point out that at other times and places they have bid large bonuses and lost. Offshore Cook Inlet is undoubtedly more representative than Prudhoe Bay due to the larger number of sales and smaller size of fields discovered.

The discounted value of oil produced and estimated to be produced from Lease Sales 7 and 9 is \$1.3 billion (Table 3, column 7). Ideally, we would like to determine what portions of this value have gone to cover production costs, what portion has been collected in royalties and similar per barrel taxes, and what portions of the remaining amount were paid in lease bonuses and retained by the industry. The following discussion will be complicated by (1) imprecise measures of the value of future natural gas production; (2) imprecise estimates of production costs; (3) uncertain shares of rent collected or to be collected by royalties, severance taxes, and other taxes; (4) the value of oil and gas in fields which are under lease but have not yet produced; and (5) the number of lease sales to be included in the analysis. The effect of alternative assumptions for items 1 through 5 could be incorporated in a computer-modeled sensitivity analysis. For the purposes of this report, assumptions will be made which are biased in favor of the effectiveness of the bonus bid as an instrument for collecting rent. If the bonus bid appears to be ineffective under these favorable assumptions, then we can be reasonably confident that it, in fact, has been ineffective.

Natural gas sales from Cook Inlet fields are now approximately 11 percent of the value of oil sales. This percentage, however, has been increasing historically and is expected to continue to increase significantly in the future. Nevertheless, the discounted value of oil will only be increased by 13 percent to $1.5 billion to account for gas sales. Production costs (exclusive of interest charges since petroleum flows have been discounted to the present) in 1975 dollars are assumed to be $1.25 per barrel, which may be somewhat low, or $2.50 per barrel which is definitely high. The average wellhead price of crude oil in 1975 dollars reached a high in 1965 of $5.66 a barrel, declined to $4.26 in 1973, rose dramatically to $5.38 in 1974, and is likely to increase gradually in the future. Nevertheless, for this analysis, we assume a constant price of $5.00 per barrel. The state collects a 12.5 percent royalty, a severance tax of 3 percent to 8 percent depending on the rate of production, and has occasionally levied other smaller production taxes as well as occasionally granted discovery credits. For the purposes of this analysis, we assume these payments average 20 percent of the value of petroleum produced which is undoubtedly somewhat higher than actually the case. Lastly, we assume that all the oil and gas fields that will ever be produced up to Lease Sale 16 are now producing, and we assume that these 11 sales constitute a meaningfully large sample.

Given the above assumptions, production costs plus royalties and related payments come to 0.45 to 0.70 of the discounted value of the petroleum. The 0.30 to 0.55 remaining share has a discounted value of $450 million to $825 million. What proportion of this amount was collected in lease bonus payments? The value of the lease bonus payments discounted to 1961, roughly the year of the sales for the tracts in which oil was discovered, equals $74 million. Thus, assuming the high production cost estimate, bonus bids transferred 16 percent of the remaining rent, after royalties, etc., to the state. With the low production cost estimate, this percentage diminishes to 9 percent. Even given the favorable assumptions, the effectiveness of the bonus bid as a method for transferring rent to the state appears to be very low.

RECOMMENDATION III.B.1. The Department of Natural Resources should conduct a more sophisticated analysis along the above lines, with attention given to the sensitivity of the conclusions to alternative assumptions.

One might still argue that offshore Cook Inlet is another bad-luck example for the state of Alaska but that, with a large number of sales, the state will earn a fair return over the long run. This may be true in theory. But given the tremendous variations around the mean which are possible due to the great uncertainties involved, the state should (1) consider whether it has enough petroleum lands to lease to be reasonably certain that the law of large numbers is relevant and (2) whether it has sufficient planning expertise and access to capital to cope with the variations in bonus bid flows over time.

RECOMMENDATION III.B.2. The Department of Natural Resources should employ a statistician to assess alternative confidence limits about the mean for bonus bid revenues in 2-year, 5-year, and 10-year intervals given the projected pace of acreage to be leased in the future.

IV. Conclusions

The lease bonus bid appears to have been between 5 and 20 percent effective as a means of collecting rent over and above that collected through royalties. Its historic ineffectiveness may be due to extensive risk discounting on the part of industry, low levels of competition and the use of game theory by industry in determining bids, simply bad luck, or a combination of all of these. Regardless of the reason, both the theory and evidence brought out in this report suggest the state of Alaska should seriously consider alternative leasing systems, initiating or participating in presale exploration, acquiring the expertise to establish competitive bid rejection values for each tract, or a combination of all three of these.

This portion of the overall study does not address alternative lease terms or procedures for determining lease winners. If the state retains the lease bonus bid approach, especially with current royalty levels, its effectiveness can be increased in two interrelated ways. First, the state could contract or provide incentives for limited exploratory drilling with public dissemination of information prior to lease sales. This information could reduce uncertainty substantially and thereby increase the level of competition. Second, the state could, itself, behave as a bidder by establishing competitive bid rejection criteria for each tract. Such an approach at least would increase the level of competition substantially, for example, from 2.2 to 3.2 serious bidders on likely tracts in Lease Sale 9. But more importantly, the state's bid could reduce the effectiveness of game theoretic strategies significantly, thereby having a bigger impact than merely increasing the number of bidders. Each of these approaches can be developed over time with increasing intensity or sophistication. There effectiveness and cost can be monitored and optimal levels roughly determined. These proposals cannot be rejected on the grounds that staffing and expenditures comparable to Exxon's exploration division would be required.

Even if the lease bonus bid approach is abandoned, some changes along the above lines would probably be desirable. First, there is no known perfect set of lease terms or procedures of determining lease winners under conditions of uncertainty and limited competition. While other leasing strategies may be better, there will probably still be advantages to reducing uncertainty and increasing competition. Second, the state could better plan sales over time and predict revenue flows if it had information on areas to be leased. Again, such information might be gathered by initiating or providing incentives to industry to drill. Or it may be sufficient for the state to participate in industry-initiated seismic exploration and to employ several seismologists or contract for the analysis of seismic data.

In summary, the Department of Natural Resources should seriously consider increasing its level of expertise and role in exploration, incrementally over time but substantially during the next 5 to 10 years.

Appendix F

ROYALTIES ON PETROLEUM PRODUCTION: RECOMMENDATIONS ON FOUR POLICY CONSIDERATIONS

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January 1977

TABLE OF CONTENTS

Four basic policy objectives are considered in this paper with respect to determining the optimal royalty rate on State of Alaska oil and gas leases. These policy objectives are

1. Maximizing the lease bonus and the present value of the royalties received by the state.
2. Maximizing the economically feasible production of oil and gas from each lease.
3. Maintaining, and enhancing where economically feasible, employment and economic activity levels in the state and the affected local communities.
4. Increasing the number of bidders at lease sales.

The basic conclusion of this paper is that an increase in the average royalty rate probably would increase substantially the lease bonus and the present value of the royalties received by the State of Alaska. If the increase in the average royalty rate is obtained by means of a multipart royalty schedule, all four of the above policy objectives can be attained simultaneously. Increasing the flat rate royalty above the customary one-sixth of gross revenues will attain policy objectives one and four; however, it would almost certainly fail to attain policy objectives two and three.

As is indicated at a number of points throughout this paper, additional research should be performed to firm up these conclusions. The simulation model which was used to estimate the impact of higher royalty rates or multipart royalty schedules on the State revenues and on the total amount of oil and gas produced from the lease needs to be supplied with data more typical of Alaskan operating conditions (it was based on Gulf of Mexico offshore operations). The model also should be modified to permit consideration of the impact of higher royalty rates on (1) the appropriate interest rates for computing the present values of the lessee and the State's cash flow streams and (2) the level of the lessee's investments in exploring, developing and producing the lease.

This paper is divided into three sections. In the first section, the basic economic functions of royalties are discussed relative to the policy objective of maximizing the State's lease bonus revenues and the present value of its royalty receipts. The second section is concerned with the two principal economic critiques of higher royalty rates, again primarily in the context of the first policy objective. The other three policy objectives are treated in the third section of the paper and its principal conclusions with respect to all four policy objectives are discussed.

CHAPTER 1

ECONOMIC FUNCTIONS OF ROYALTY PAYMENTS

Determination of the optimal terms under which to lease a parcel of land for mineral extraction involves consideration of the relationship between changes in the royalty rate and the change in the landowner's wealth from leasing the land. In this regard, royalty payments serve two primary functions. One function is to transfer all or a portion of the economic rents inherent in the property from the firm extracting the minerals to the landowner. The second function of royalties is to permit the landowner to bear some portion of the risks inherent in the process of finding, developing and extracting minerals from the property.

Where the landowner is a government agency, other public policy considerations may enter into determination of the optimal royalty rate. These policy considerations include (1) maximizing the reserves[1] of the mineral, (2) maintaining or enhancing employment levels and economic progress within the community, and (3) increasing the number of bidders for the lease. The relationship between these policy considerations and the level of the royalty rate are discussed in chapter three.

The definition of wealth used throughout this paper is that used by the industry in assessing whether it is profitable to make a specified investment or to take some other action. That is, the contribution to the landowner's wealth resulting from leasing a tract of land is the present value of the cash flows paid by the lessee. For government owned lands, these cash flows primarily are the lease bonus, the royalty and/or land rental, severance and/or property taxes, and the income taxes paid by the lessee. Secondary governmental cash flows generated by the increased investment, employment and economic activity levels resulting from the exploration, development and production activities of the lessee may also be included in the economic evaluation of the optimal royalty rate for a given lease or set of leases. When these secondary governmental revenues are considered, it is also appropriate to consider (1) the additional public services expenditures to be incurred by the government as a result of the decision to lease the land and (2) the environmental impacts and externalities generated by the exploration, development and production of the lease. Although these secondary effects can be very important--especially where small, basically rural, communities are involved--the study upon which this paper is based did not include consideration of secondary economic impacts generated by the decision to lease government lands. A full economic and environmental impact assessment would include an evaluation of these secondary effects.

There are three principal dimensions calculating the present value (PV) of the alternative leasing policies: the level of the cash flow, its timing, and the interest rate. The general formula is

$$PV = \sum_{t=0}^{n} \frac{F_t}{(1+i)^t}$$

Where F_t is the level of the cash flow received at time t, "i" is the appropriate rate of interest, and "n" is the time when the lease is to be terminated. Royalty rate policies can affect the level of the landowner's cash flow, the appropriate rate of interest, and--in some cases--the timing of the cash flows. The first two factors are discussed in the remainder of this chapter. The third factor is treated briefly in chapter two.

The cash flows from a given tract of land depend upon several economic and technological factors, in addition to the lease bonus and royalty rate policies adopted by the landowner. They include:

1. The delivered price of oil from other sources in the market or markets to which the oil from the lease would be shipped.
2. The cost of transporting the oil from the lease to the markets in which it is to be sold.[2]
3. The costs of exploring, developing, and operating the lease. These costs depend upon the physical nature of the reservoir (including such factors as its depth; the gravity, sulfur content, and other properties of the oil; its permeability, porosity, energy source, etc.), the nature of the climate, terrain, and ecological conditions where the lease is located, and the technologies available to the industry, the costs of labor and materials delivered to the lease, and the general administrative costs allocated to operating the lease.
4. The income, severance, property, franchise and other taxes imposed on the lessee.
5. The costs of the debt and equity capital invested in evaluating and acquiring the lease, and in exploring, developing and producing the lease.

Increases in taxes, the cost of capital or the costs of funding, developing, producing, or transporting the oil reduce the lessee's cash flow and, thus, the economic rents inherent in the tract to be leased. Reductions in the delivered prices of competing oils similarly reduce the economic rents. All of these factors must be taken into consideration by the landowner in determining the wealth maximizing lease terms for specific tracts of land. These factors, and possibly other factors as well, are analyzed by petroleum engineers in their economic evaluations of leases. For the purposes of this paper, these factors are taken as givens and varied parametrically in the evaluation of the relationship between changes in lease terms and the landowner's wealth.

1.1 Royalties As a Means of Transferring the Economic Rents Inherent in the Lease to the Landowner

The economic rent inherent in a tract of land is the increase in the lessee's wealth in excess of that increase which is just sufficient to get the lessee to explore, develop and produce the minerals in the land. As applied to the leasing of mineral lands, the term "ex. ante. economic rents" applies to the situation at the time the lease contract is awarded. That is, a wealth-maximizing landowner would want to lease the lands under the set of terms that reduces the present value of the lease, from the lessee's point of view, to as near to zero as is feasible.[3] So long as the expected present value of the lease is positive, the potential lessee will be willing to invest in acquiring the lease and its development.

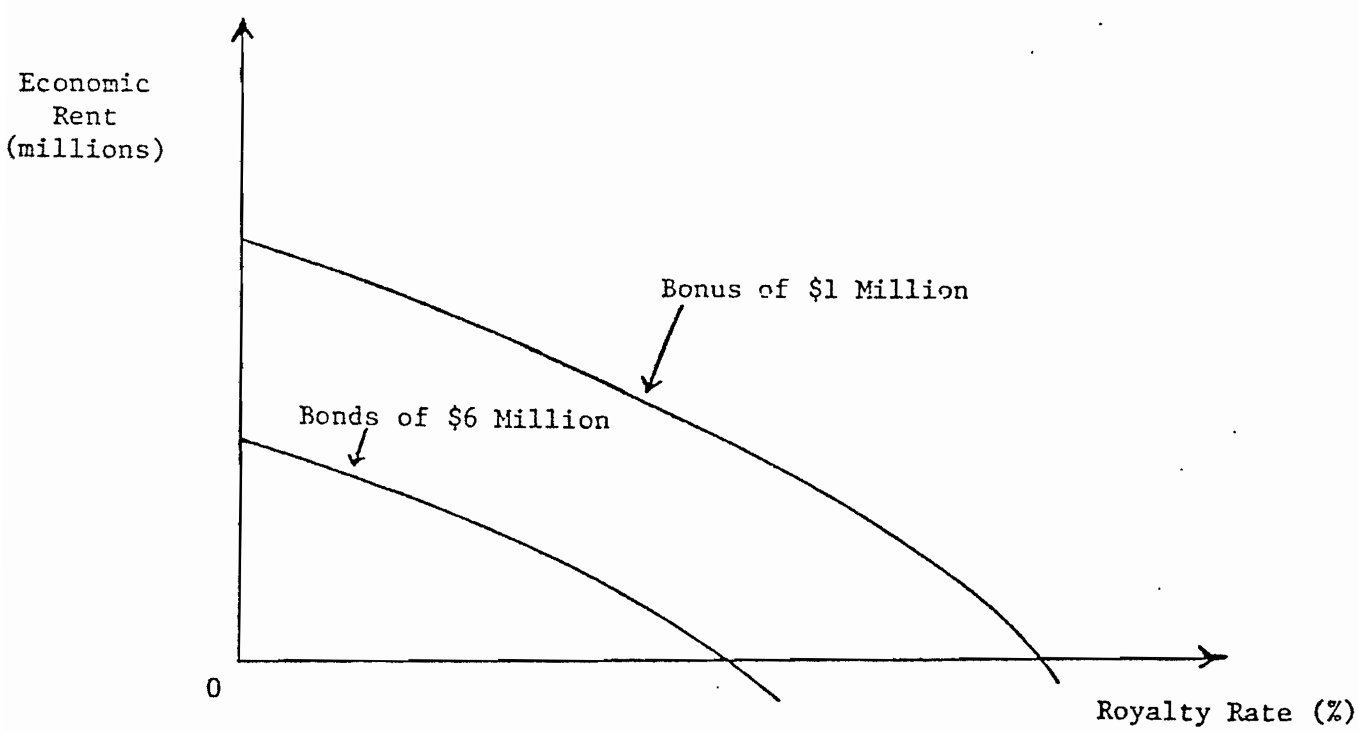
The term "ex. post. economic rents" is applied to the actual results of exploring, developing and producing the lease after the lease contract is signed. In general, unless there are specific provisions for renegotiating the lease terms, the private landowner cannot capture all or part of any increase in the ex. post. economic rents over the ex. ante. rents, nor can the lessee obtain a return of a portion of the contractual bonus and royalty payments if the ex. ante. economic rents exceed the ex. post. rents. Governmental landowners may, however, obtain all or a portion of any difference between the ex. ante. and the ex. post. economic rents by changing general tax rates or imposing new taxes.

For those mineral properties which are expected to be sufficiently productive to give rise to potential economic rents for the lessee, the private landowner generally has two methods for transferring the expected rents to himself. In addition to these two methods, governmental landowners can obtain a portion of the economic rents inherent in the lease through various taxes. One method is to require the lessee to pay as a royalty a percentage of the gross revenues from the sale of minerals produced from the tract of land.[4] The second method is to require the lessee to pay a bonus to the landowner at the time the lease is signed. In general both methods are used for reasons discussed in section 1.2. In principle, by setting either the royalty rate or the lease bonus at a sufficiently high level, the <u>ex</u>. <u>ante</u>. economic rents inherent in the tract of land can be transferred from the lessee to the landowner.

An increase in the royalty rate will reduce the economic rent inherent in the tract, as will an increase in the lease bonus. Moreover, for any specified level of the lease bonus less than the level of economic rent inherent in the tract, there exists a royalty rate that will reduce the economic rent from the lessee's point of view to zero. This relationship is illustrated in Figure 1 for two hypothetical lease bonus amounts,

Figure 1

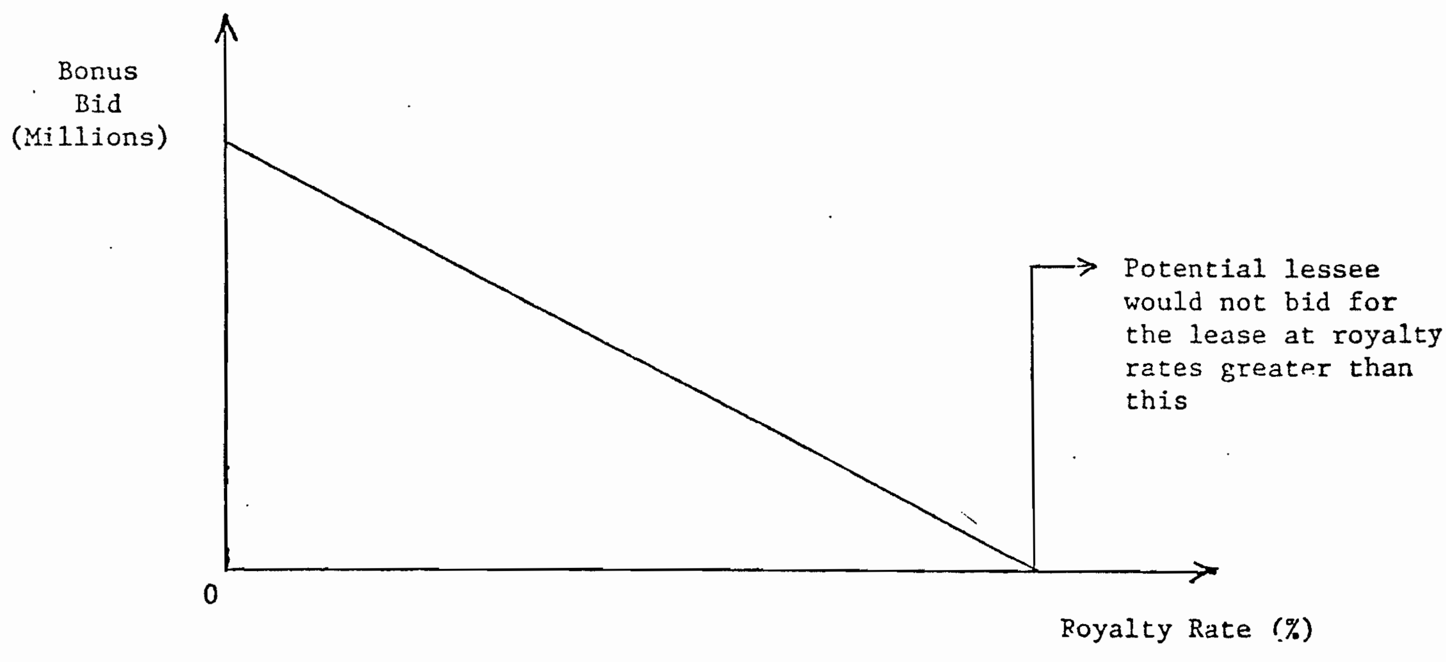
Relationship Between the Royalty Rate, the Lease Bonus and the Level of Economic Rent



When competitive bonus bidding is used to select the firm to receive the lease, the landowner generally expects the competitive bidding process to reduce to zero the ex. ante. economic rents inherent in the tract from the lessee's point of view.[5] Since the royalty rate (usually one-sixth of gross revenues) is specified in the lease terms, the level of economic rents inherent in the tract of land from the point of view of the lessee, and thus the maximum lease bonus the lessee would be willing to pay, depends upon the level of the royalty rate. If the rate of interest for computing the present value of the lessee's cash flow is held constant (a simplifying assumption--see section 1.2), an increase in the royalty rate will result in a reduction in the economic rents inherent in the tract of land and, thus, the lease bonus. This general relationship is illustrated in Figure 2.[6]

Figure 2

Relationship Between Bonus Bid and Royalty Rate



From the private landowner's point of view, the total economic rent which he obtains is the sum of the lease bonus and the present value of the royalty payments. Although competitive bonus bidding with the customary one-sixth royalty rate can, in principle at least, result in transferring most or all of the economic rents inherent in the tract from the lessee to the landowner, does the customary one-sixth royalty maximize the total economic rent to be obtained from the lease. In general, the answer to this question is "No!". If the interest rates for calculating the present value of the lessee's after-tax cash flow and the landowner's royalty payments are held constant with changes in the royalty rate, increasing the royalty rate up to at least four- or five-sixths increases the present value of the landowner's royalty receipts by substantially more than it decreases the maximum lease bonus that the landowner would be willing to pay. Table 1 presents the results of calculations of the maximum lease bonus and the present value of royalty receipts for a simulated exploratory lease. The general relationship between the present value of total landowner receipts and the royalty rate is graphed in Figure 3.

In general, increasing the royalty rate increases the present value of the landowner's total receipts from lease bonus and royalty payments for royalty rates up to five-sixths of total revenues. The increases in total receipts are at a decreasing rate as the royalty rate increases. In the example in Table 1, at a royalty rate only slightly greater than five-sixths, the maximum bonus bid would become negative--which means that the potential lessee would not bid on the lease because it would be unprofitable to do so. Thus, based on this one example, increasing the royalty rate to five-sixths and awarding the lease to the firm making the highest bonus bid would result in a greater *ex. ante.* economic rent to be captured by the landowner than the customary one-sixth royalty rate and competitive bonus bidding.

The author has made many similar simulation studies and found the same general conclusion--that increasing the royalty rate to three-sixths or more

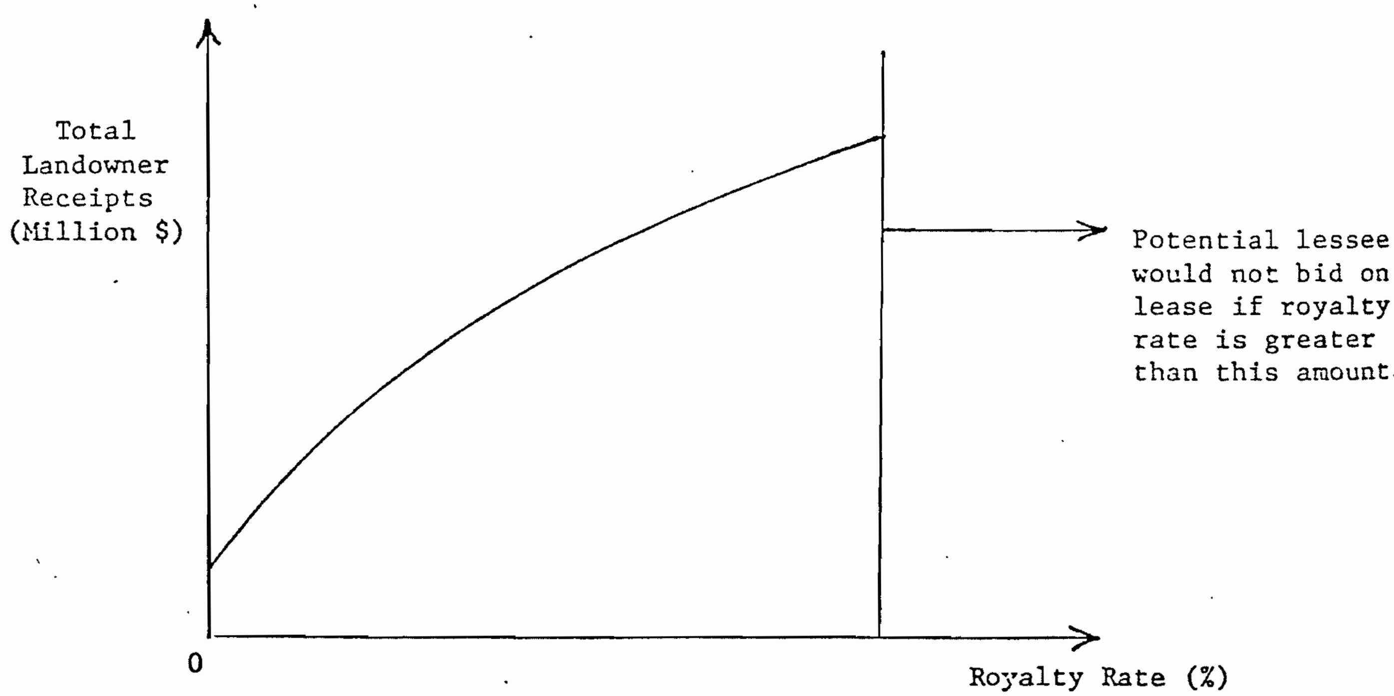
Table 1

Example of Relationship Between the Royalty Rate and Landowner Receipts
(Millions)

Royalty Rate	Maximum Bonus Bid	Present Value of Royalties	Landowner Receipts Total	Landowner Receipts Change
0	$17.5	$ 0.0	$17.5	Base
1/6	14.0	19.9	33.9	$+16.4
2/6	10.5	39.5	50.0	+16.1
3/6	7.0	59.0	66.0	+16.0
4/6	3.6	77.2	80.8	+14.8
5/6	0.2	88.9	91.0	+10.2

Figure 3

Relationship Between Royalty Rate and Landowner Receipts



increases the present value of the landowner's receipts from the lease. These studies included cases where the well-head price of the oil was $7 per barrel and finding, developing and producing costs were double the estimated 1976 costs for offshore Gulf of Mexico leases. Runs were not made using estimates of Alaskan North Slope well productivities, well-head prices, and costs.

This general conclusion, however, is subject to two major reservations. The first is that as the royalty rate increases, and the lease bonus paid by the lessee decreases, the landowner is assuming a greater proportion of the risk that the lease may be unproductive or less productive than was assumed by the lessee at the time he bid for the lease. Similarly, the lessee is bearing a smaller proportion of these risks. Since the interest rate for calculating the present values depends upon the proportion of the risks inherent in exploration and development of the lease assumed by the party receiving the cash flow stream, the interest rate for the lessee should fall with a rising interest rate and the interest rate for the landowner should rise. This reservation is discussed in the section 1.2 of this paper.

The second reservation has to do with the impact of the higher royalty rate on the percentage of the total mineral resources that will be recovered by the lessee--that is on the oil reserves created by exploration and development of the lease. Although the present value of the total receipts of the landowner can be maximized by increasing the royalty rate, the reserves created by the lease will decline. This decline in reserves is a direct result of adopting a higher royalty rate to transfer economic rents to the landowner. This reservation with respect to increasing the royalty rate over the customary one-sixth rate, and the use of multipart royalty schedules to mitigate this effect, are discussed in sections 2.2 and 3.1.

If the landowner is a governmental entity, such as the federal government or a state, the optimal royalty rate policy must consider the impact of changes in the royalty rate on its tax revenues, and the tax revenues of its political subdivisions where severance taxes or property taxes on oil reserves are important sources of revenues.[7] In the case of the federal government, its relatively high coprorate income tax rate makes its income tax receipts sensitive to the royalty rate since royalties are deductible as a normal business expense. An example of this relationship, which is based on the same simulation study as was used to generate Table 1, is in Table 2.

For all royalty rates up to five-sixths of gross revenues, the increase in the federal government's royalties exceeded the decrease in the federal government's income tax revenues. Thus, based on this sample simulation study, there is a net increase in the present value of the federal government's revenues from the lease if the royalty rate is increased. Since state income tax rates are substantially lower than federal income tax rates, the reduction in state income tax revenues resulting from an increase in the royalty rate would be substantially less than the amounts indicated in Table 2.

The impact of changes in the royalty rate on the severance tax revenues of the political subdivisions of the state results from the reduction in reserves that accompanies increases in the royalty rate (see section 2.1). Since this reduction occurs in the final years of the well's life and since it can be eliminated entirely by adopting a multipart royalty schedule (see section 3.1), the impact of a higher royalty rate on the severance tax revenues of the state's political subdivisions is either minimal or easily compensated for by transfer payments to the political subdivisions financed out of the state's increased royalty receipts. Moreover, since both royalties paid to a state and severance taxes paid to a state or one of its political subdivisions are deductions for the purpose of computing the lessee's federal income tax liabilities, much of the burden of increases in royalties or state and local taxes is borne by the federal government rather than by the state or lessee.

Table 2

Example of the Relationship Between Changes in the Royalty Rate and Federal Income Tax Revenues
(Million $)

Royalty Rate	Present Value of Royalty Receipts		Present Value of Income Taxes	
	Amount	Change	Amount	Change
zero	-0-	Base	$47.0	Base
one-sixth	$19.9	$+19.9	37.1	$ -9.0
two-sixths	39.5	+19.6	27.1	-10.0
three-sixths	59.0	+19.5	17.2	-9.9
four-sixths	77.2	+18.2	7.3	-9.9
five-sixths	88.9	+11.7	-2.5*	-9.8

*Negative value indicates tax losses which can be written-off against other income earned by the lessee.

1.2 Royalties As a Means of Sharing the Risks Inherent in Exploring, Developing, and Producing the Property

Mineral exploration in general and petroleum exploration in particular are subject to a relatively high level of uncertainty with respect to both the functional form and parameters of the probability distributions associated with the several geological characteristics of a tract of land and the appropriate technologies for extracting any minerals that may be present. In addition, even when the relevant probability distributions and their parameters are determined to a degree acceptable to the decision maker, the variances of the probability distributions generally are felt to be relatively greater than those faced by most investments of capital in the American economy, which is why petroleum exploration and development is generally felt to be a relatively risky business.

Because of the relatively high degree of risk associated with these investments, the landowner may find it to be wealth maximizing to bear a greater portion of the risks and uncertainties associated with the exploration and development of his lands by increasing the royalty rate. By assuming a greater portion of the inherent risks, the landowner may be able to reduce the interest rate used by potential lessees in calculating the maximum bonus bid they would be willing to pay to acquire the lease, which would increase the bonus bids. The cost of this rise in the bonus bid is an increase in the interest rate which the landowner uses to calculate the present value of his royalty receipts, which tends to reduce their present value. These general relationships between the royalty rate and the appropriate interest rate to use in calculating present values are illustrated in Figures 4 and 5.

Figure 4

General Relationship Between the Royalty Rate and the Interest Rate for Discounting the Lessee's Cash Flows

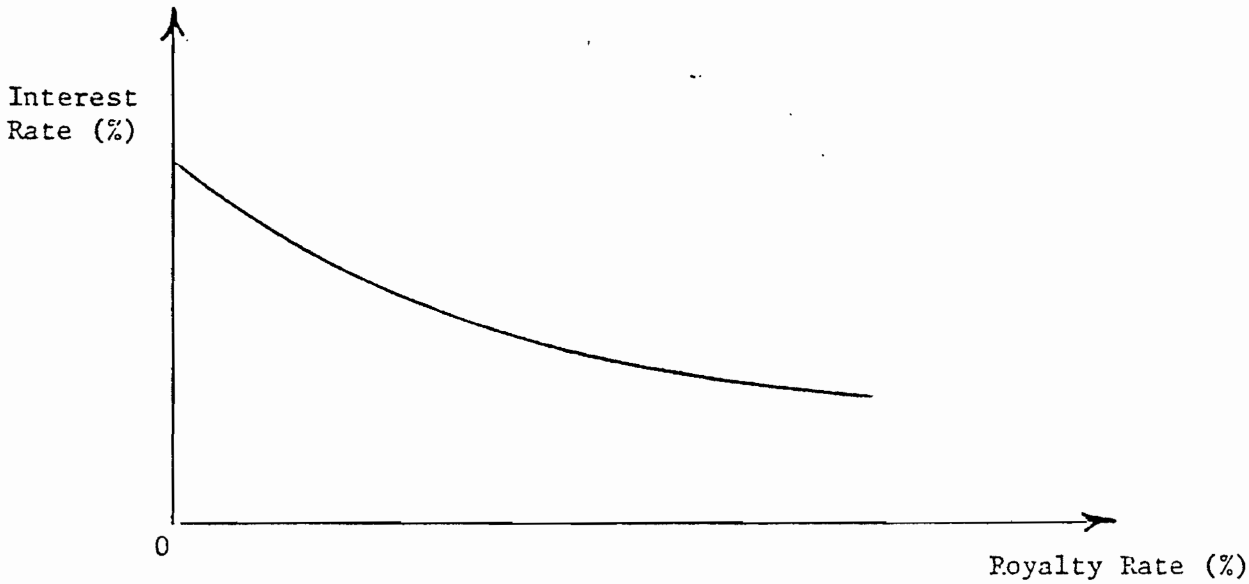
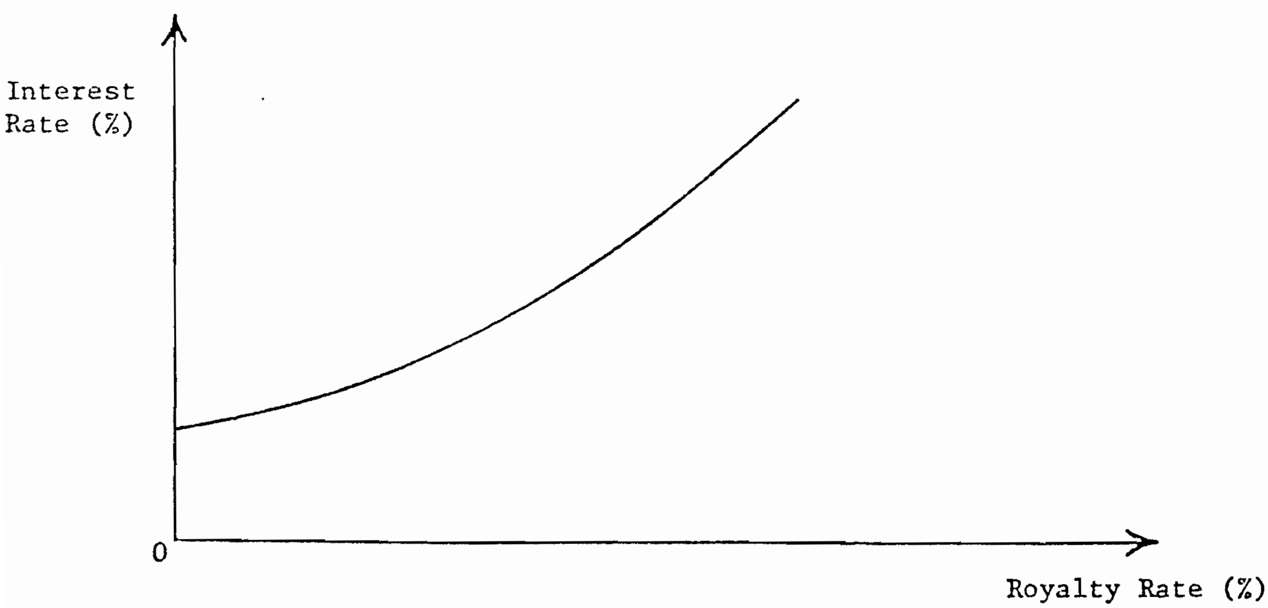


Figure 5

General Relationship Between the Royalty Rate and the Interest Rate for Discounting the Landowner's Cash Flows



The potential impact of these interest rate changes on the landowner's wealth is illustrated in Table 3, which was obtained from the simulation study used to generate Table 1. Note that both the maximum lease bonus and the present value of the landowner's royalties are relatively sensitive to the interest rate. Unfortunately, the simulation study on which Table 3 is based did not consider higher interest rates for the landowner or lower interest rates for the lessee. Had such a study been made, it is very likely that a numerical example could be constructed showing that an increase in the royalty could so change the two interest rates that the present value of the landowner's total receipts (lease bonus plus royalties) would fall.

The general relationships in Figures 4 and 5 are based on the conventional premise that investors in future income streams are risk-aversive. That is, when given a choice between two options with the same internal rate of return, the risk-aversive investor would choose the less risky option. There is both theoretical and empirical evidence that investors in oil and gas exploration and development (i.e., the oil companies) are not risk-aversive, but rather are risk-seekers. If this is the case, the interest rate which the potential lessees would use to calculate the maximum lease bonus they would be willing to pay to the landowner would fall with an increase in the portion of the risk inherent in the lease that they must bear. That is, the general relationship in Figure 4 would become that in Figure 6.

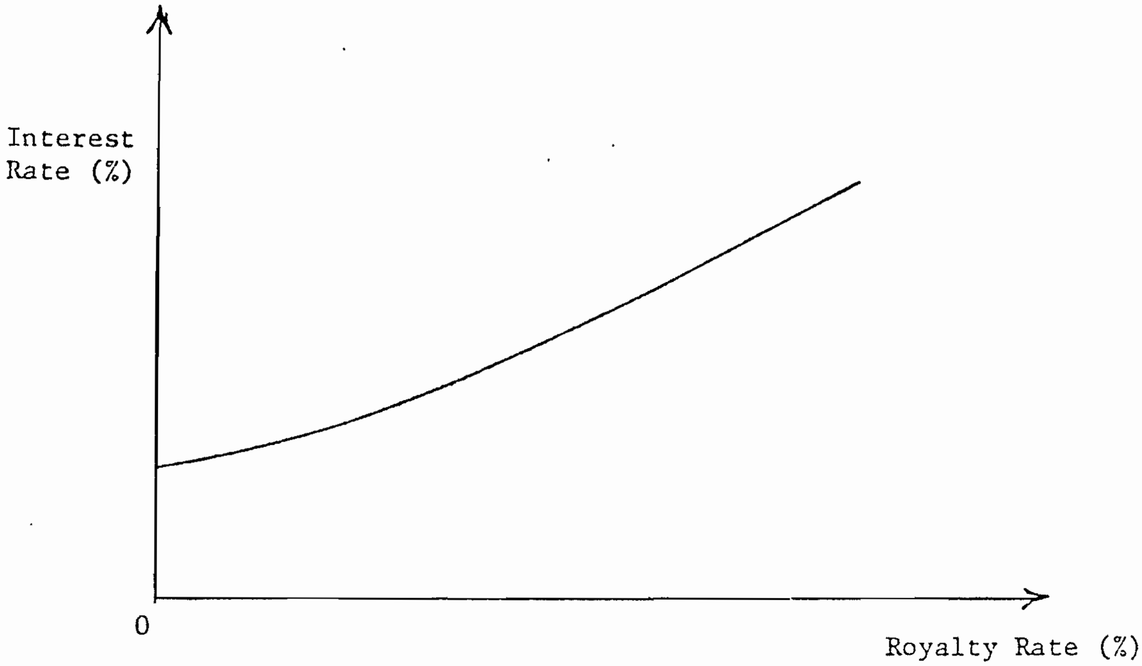
Table 3

Example of the Relationship Between Changes in the Royalty and Interest Rate and the Maximum Lease Bonus and Present Value of Royalties
(Millions of $)

Royalty Rate	Lessee		Landowner	
	Interest Rate	Lease Bonus	Interest Rate	PV of Royalties
zero	20%	$17.5	6%	-0-
	25	12.7	9	-0-
	30	9.4	12	-0-
one-sixth	20%	$14.0	6%	$19.9
	25	10.1	9	15.2
	30	7.4	12	12.0
three-sixths	20%	$ 7.0	6%	$59.0
	25	4.8	9	45.5
	30	3.3	12	36.0
five-sixths	20%	$ 0.2	6	$88.9
	25	(0.3)	9	70.6
	30	(0.6)	12	56.9

Figure 6

General Relationship Between the Royalty Rate and the Interest Rate for Discounting a Risk-Seeking Lessee's Cash Flow



If the relationship between the lessee's interest rate and the royalty rate is that implied by Figure 6, rather than by Figure 4, the wealth maximizing leasing policy for the landowner probably would be to set a relatively low royalty rate.

There is still another school-of-thought that argues where the government is the landowner, the appropriate interest rate should be the default-risk-free rate of interest on long-term U.S. government bonds. (This interest rate is not entirely risk-free since the owner of long-term U.S. government bonds must bear the risks of unanticipated changes in the rate of inflation.) Furthermore, this school-of-thought argues that the government should be risk-neutral in its decisions, which implies that the same interest rate would be used to calculate the present value of royalties regardless of the level of the royalty rate. Thus, the potential lessee's interest rate would fall with increases in the royalty rate. This implies that the governmental landowner would almost certainly benefit from increases in the royalty rate.

In the author's opinion, the relationship between royalty rates and the interest rates appropriate for computing the present values of both the lessee's and the landowner's cash flows requires further research before optimal royalty rate policies can be determined. This research would involve two separate issues:

1. A study of the relationship between the level of the royalty rate and the proportion of the risk inherent in the tract of land borne by the lessee and the landowner.
2. A study of the relationship between the portion of the inherent risk borne by each party and the appropriate interest rates for computing the present value of their cash flows.

Based on his search of the available literature, the author does not know of any studies which specifically address either of these issues in the context of determining the optimal royalty rate for a specific tract of land. In the absence of such studies, it is the author's opinion that increases in the royalty rate beyond three-sixths (50%) of gross revenue from the lease should be approached with considerable caution. However, based on the author's simulation studies, it appears likely that increasing the royalty rate to three-sixths would substantially increase the landowner's wealth under present market conditions. A significant reduction in the new-oil[8] price below current levels would likely imply a lower royalty rate than three-sixths.

CHAPTER 2

ECONOMIC CRITIQUES OF ROYALTY PAYMENTS

Although increases in the royalty rate applied to the gross revenues of an oil lease above the customary one-sixth royalty are likely to increase the total lease bonus and royalty receipts of the landowner, net of reductions in income tax revenues in the case of governmental landowners, there are two major economic critiques of the use of higher royalty rates to transfer economic rents from the lessee to the landowner. One of these critiques is that an increase in royalty rates will result in a reduction in the total production of petroleum from the lease relative to the rate of production that would result if some other means of transferring economic rents were used. This critique is discussed in section 2.1. The second critique, which is the more serious one, is that higher royalty rates will result in a reduction in the intensity of the lessee's exploration and development efforts and in his incentives to engage in pressure maintenance and secondary recovery projects. This critique is discussed in section 2.2 of this paper.

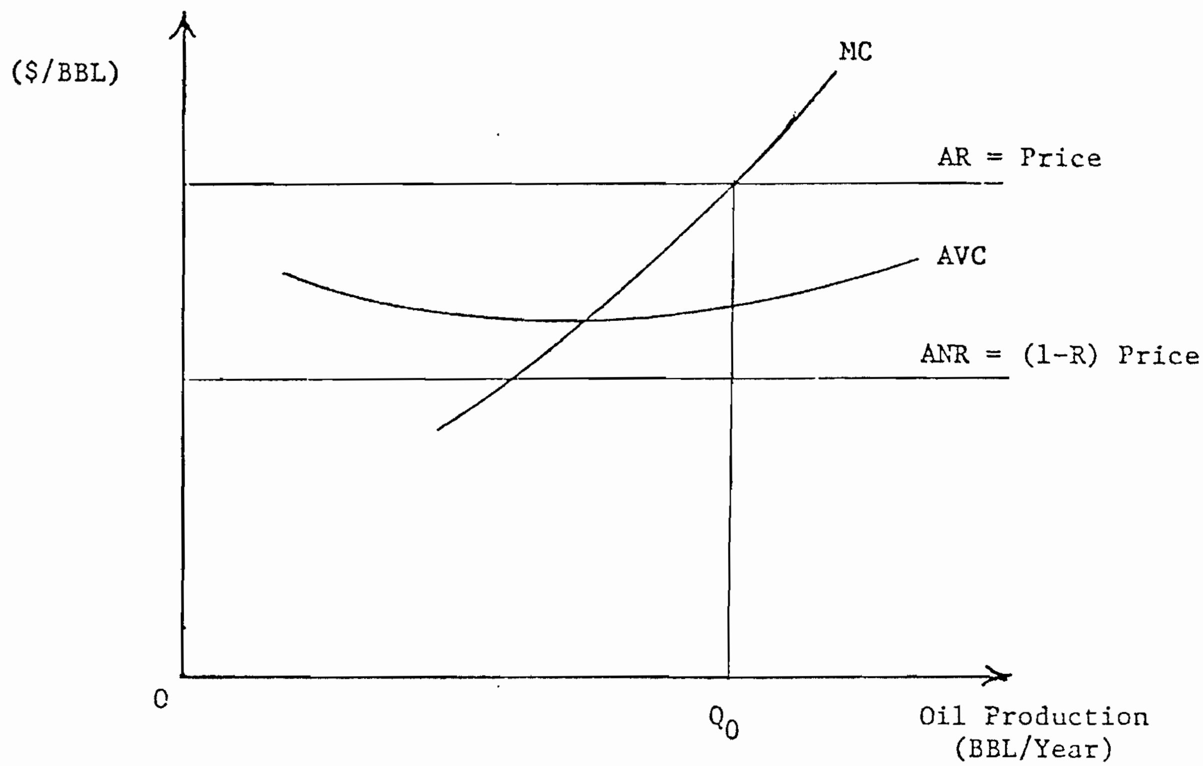
2.1 Loss in Reserves Due to a Higher Royalty Rate

The traditional argument against royalties based on gross revenues as a menas of transferring economic rents from the lessee to the landowner is based on the observation that positive royalty rates will result in earlier abandonment of the well or field than would be the case if the royalty rate were zero. According to the traditional argument, since the lessee views the royalty payment as a production cost, the lessee will abandon the well or field when his average variable cost of production exceeds his average revenue net of the royalty, In Figure 7, the lessee would continue producing oil from the lease if the royalty rate were zero; however, given the royalty rate, R, his average net revenue (ANR) would be less than his average variable costs of production (AVC) for all rates of oil production. Hence, the lessee would abandon the lease and all the oil that would have been produced if the royalty rate were zero would be lost to society since it generally only pays to reopen an abandoned well when there is an exceptionally large unexpected increase in the price of oil.[9] A corollary to this argument is that the higher the royalty rate, the sooner the well or field will be abandoned and the greater the unnecessary loss in oil reserves. Given the national objectives with respect to increasing the nation's energy selfsufficiency and the impact of oil field abandonments on the economies of states and, especially, localities, this critigue can assume considerable importance in governmental leasing policy decisions.

Figure 8 provides another way to look at the resource misallocations resulting from the use of a royalty to transfer a portion of the economic rents from the lessee to the landowner. The royalty payment does not bring

Figure 7

Oil Production Costs and Revenues



forth any additional production of petroleum for the economy. Since capital, labor and natural resources have already been allocated to developing and producing the lease, petroleum should be extracted from the lease so long as its market value exceeds the current costs of producing it. If the royalty rate were zero, the well or field would be abandoned at time T_0; whereas, with royalty rate R, the revenues to the producer, PQ, would be reduced to (1-R)PQ and the well or field would be abandoned at time T_1. All of the oil that would have been produced between time T_1 and T_0 (see Figure 9) is lost to the economy because the royalty rate was set at R instead of zero. Thus, the positive royalty rate results in an increase in the amount of capital, labor and natural resources that must be allocated to producing a given amount of oil.

There are, however, significant counterarguments to this position. One counterargument with particular application to oil fields and some types of mining operations is that it is not the inexorable increase in the cost of operating an oil field, per barrel of oil produced, that generally leads to the abandonment of a well or field. In general, it is a mechanical problem with the well or the producing equipment of the field which requires a substantial new investment on the part of the operator that leads to the abandonment decision. That is, given the well or field's low productivity due to its depletion, the present value of the operator's future cash flow simply is not great enough to cover the cost of reworking the well or the new equipment for the field. In many cases, this counterargument contends, the cost of reworking the well or the new equipment is so great relative to the productivity of the well or field that even a zero royalty rate would lead to abandonment. Hence, the abandonment decision generally is independent of the royalty rate, although this counterargument is likely to lose much of its

Figure 8

Early Abandonment of a Well or Field
Induced by a Positive Royalty Rate

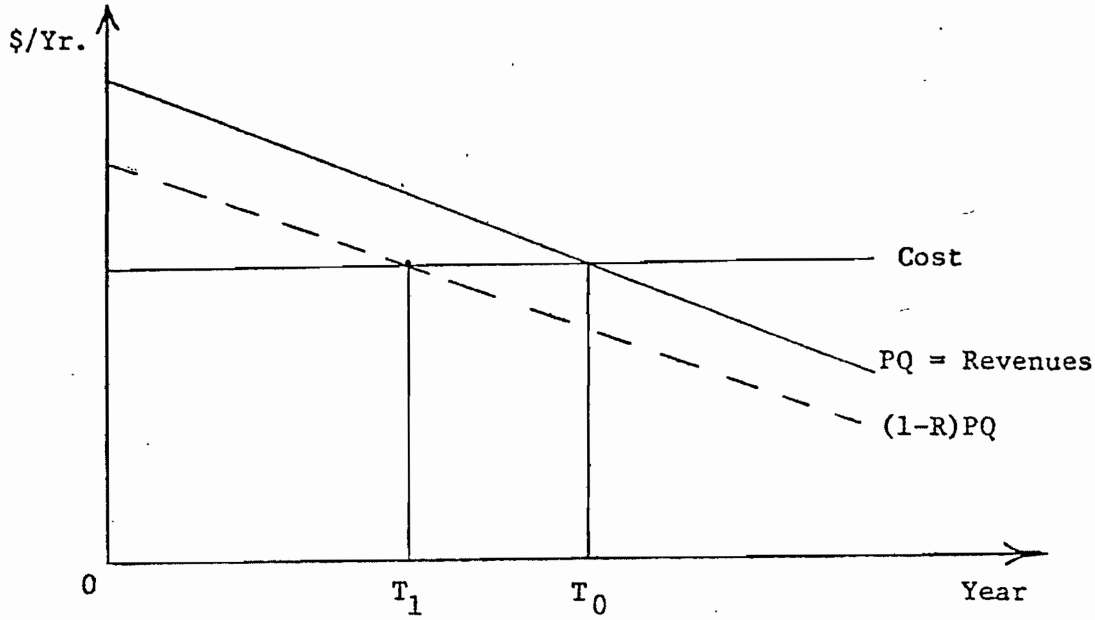
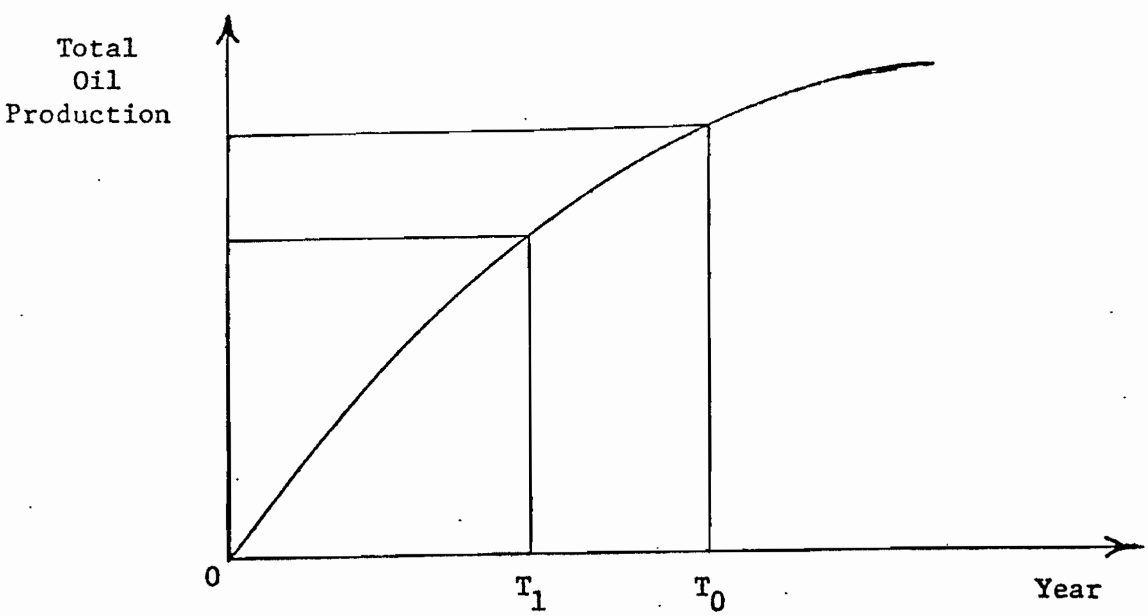


Figure 9

Total Oil Production Over the Life of
a Well or Field
(Barrels)



reasonableness when the royalty rate substantially exceeds the customary one-sixth rate.

This counterargument is based on the author's experience in the industry and on his conversations over the past fifteen years with a number of industry people responsible for the operations of oil fields, principally in California. The author is aware of no empirical studies that would either support or reject this counterargument. Such a study very likely could be performed for California using the records of the Division of Oil and Gas, although some degree of industry cooperation likely would also be required.

The second counterargument is provided by the author's simulation studies. As is indicated by the data in Table 4, which is from the same study as the previous three tables, the loss in reserves due to an increase in the royalty rate from zero or one-sixth to three-sixths is not exceptionally large. In the case of the simulated field for Table 4, increasing the royalty rate from zero to three-sixths resulted in a 3.55% reduction in reserves. Using the customary one-sixth as the base, this percentage reduction in reserves becomes 3.10%. The corresponding percentage increase from the one-sixth royalty rate in royalty receipts is 196.5%. Moreover, if the increase in the present value of royalties ($59.0 - $19.9 = $39.1 million) is divided by the reduction in reserves (0.67 million barrels), the loss in royalties per barrel of reserves exceeds $58 per barrel.[10] This means that the landowner could buy 0.67 million barrels of foreign crude oil at current market prices and store it at a cost that would be substantially lower than the per barrel royalty receipts that would be foregone if the customary one-sixth royalty was incorporated in the lease terms rather than a three-sixths royalty.

These calculations of the relationship between increases in the royalty rate and the resulting reductions in oil reserves are based on a simulated

Table 4

Example of the Reduction in Oil Reserves Due to An Increase in the Royalty Rate (Million Barrels)

Royalty Rate	Oil Reserves	Change in Reserves*	
		Amount	Percentage
zero	21.69	Base	Base
one-sixth	21.59	(0.10)	(0.46)%
two-sixths	21.23	(0.46)	(2.12)
three-sixths	20.92	(0.77)	(3.55)
four-sixths	19.85	(1.84)	(8.48)
five-sixths	17.00	(4.69)	(21.62)

*Measured from reserves when the royalty rate is zero.

oil field that may not be typical of all oil fields in the continental United States or Alaska. However, the same basic result was obtained in virtually all of the simulation studies performed by the author. These studies covered a wide range of well and field productivities, development and operating costs and posted prices for the field. In the author's opinion, it is very unlikely that this general relationship between the increase in royalty receipts and the reduction in oil reserves will not be observed for most new fields in the United States, with the possible exceptions of marginally productive fields and of remote fields in Alaska where the posted price is substantially below current new-oil delivered prices due to high transportation costs.

In conclusion, it does not appear that the traditional economic argument against royalties has much relevance for leasing policy where the goal is maximizing the present value of the landowner's receipts. None-the-less, before royalties greater than, say, three-sixths (50%) are included in the terms of a lease to be put up for bid, a study of the potential impact of the higher royalty rate on reserves and the present value of the revenues generated by the lease would generally be appropriate where adequate data on which to base the study are available. Where the higher royalty rate may have a significant impact on the present value of the revenues generated by the lease, the mitigating measures discussed in section 3.1 should be investigated before adopting a lower royalty rate.

2.2 Impact of a Higher Royalty Rate on Investments in Exploring, Developing and Producing the Lease

The lessee of oil or mineral lands includes the royalty paid to the landowner as a cost of production in determining the amount of capital that he will commit to exploring, developing, and producing the lease. Like an increase in any other cost of production, a higher royalty rate reduces the profitability of incremental capital investments in the lease. The result is that the exploration, development and production of the lease will be less intensive than if the royalty rate were zero. The same basic point applies, of course, to income and other taxes that reduce the profitability of investing an additional dollar of capital in an enterprise.

Requiring that a bonus be paid to the landowner at the time the lease contract is signed also reduces the amount of capital that will be invested in the lease;[11] however, the lease bonus has a different effect on the investment of capital in exploring, developing and producing the lease than royalties or income taxes based on the future productivity of the lease. Although the amount of the lease bonus depends upon the royalty (and income tax) rates applicable to the future revenues from the lease, once the bonus is paid, it becomes a sunk cost that does not influence future investment decision. Future investment decisions depend upon the incremental cash flows that are generated as a result of making the new investments. Past investments are only relevant in the new investment decision process to the extent that they provide depreciation allowances that reduce future income taxes or that they provide assets which can be sold to others.

The sunk cost attribute of the lease bonus means that the lessee will invest more capital in exploring, developing and producing the lease if the royalty rate is reduced below the wealth maximizing level as calculated in section 1.1 or even eliminated. Moreover, with a zero royalty rate, the capital invested in the lease will earn the same ex. ante. rate of return, in terms of the goods and services produced, in exporting the lease as in other sectors of the economy--where the rates of return are adjusted for differences in the inherent risks and uncertainties associated with the cash flow streams. This is, of course, the basic condition for an efficient allocation of capital when the fundamental social goal is to maximize the value of the economy's capital, labor and natural resources.

As was discussed in section 1.2, relying entirely on the lease bonus to transfer the economic rents inherent in the tract of land to the landowner increases the interest rate for computing the present value of the lessee's cash flows. Thus, the total economic rents inherent in the lease--from the landowner's point of view--may be lower at a zero royalty rate than if some combination of lease bonus and royalty payment is used. However, the greater the amount of capital invested in the lease, the greater the expected future cash flows, and hence economic rents, because:

1. More capital will be invested in exploring the lease, thus increasing the probability that the petroleum deposits beneath the lease, if there are any, will be discovered and that their full extent will be determined.
2. More capital will be invested in development wells, which will result in greater reserves being created since portions of the reservoirs that would not be profitable to drill with a positive royalty rate would be drilled and produced. A somewhat greater density of development wells will likely also be profitable, which will generally add somewhat to reserves and to the rate at which the reserves are produced.
3. More capital will generally be invested in production facilities, in part to handle the higher rate of production from the field; in part

to enhance oil recovery from the reservoirs through expanded pressure maintenance and possibly additional multiple completions; and in part from more efficient, capital intensive, technologies.

4. Secondary recovery techniques, where outside energy is provided to the reservoir to increase the percentage of the original oil in place recovered, that are marginal where the royalty rate is one-sixth or greater could become attractive investments for the lessee--thus increasing reserves and the life of the field.

The simulation studies upon which the conclusions of the previous sections were based assumed that a fixed number of wells would be drilled regardless of the royalty rate and that the level of exploration and producing expenditures is independent of the level of the royalty rate. In addition, no consideration was given to the impact of the royalty rate on the prospects for secondary recovery projects. There are two reasons why the simulation model was designed in this manner:

1. The model was developed to use readily available Bureau of Mines and Industry data on on- and offshore exploration costs.
2. The model was principally constructed to study multiple part royalty schedules, rather than the flat rate royalties which were discussed in sections 1 and 2 of this paper. It was felt that multipart royalty schedules would significantly reduce the impact of higher royalties on investments in exploring, developing and producing the lease.

Whether the impact of high royalties on investments in the lease would be significant basically is an empirical question. Where the lease is expected to be relatively productive, American oil companies have entered into contracts with foreign governments (e.g., Indonesia) under terms that closely approximate flat rate royalties in excess of 50%; hence, it is unlikely that higher royalty rates will sharply reduce investment in those prospective areas where geological conditions are indicative of some possibility of large reservoirs or fields. Investments in prospects that are likely to yield small fields or reservoirs, or fields where well productivities are low, or fields where operating and transportation costs are likely to reduce the margin between the well-head price and costs to relatively low levels are more likely to be influenced by higher royalty rates, as are all secondary recovery projects. The computer program for the similation model can be modified to permit analysis of the available empirical data relevant to determining whether the impact of higher royalty rates on investment in exploring, developing, and producing the lease.

CHAPTER 3

POLICY CONSIDERATIONS OTHER THAN WEALTH MAXIMIZATION

The preceeding two sections have primarily been based on the assumption that the landowner's objective is to maximize the increase in his wealth from the lease. Where the landowner is a private party, rather than a government agency, this objective probably dominates all others. However, governments generally have other goals that their oil lands leasing policies may be required to reflect. Although there may well be others, for the purposes of this paper, two policy constraints on the level of royalty rates are discussed in this section:

1. Maximize the total amount of oil and gas produced from each reservoir consistent with the market price of the oil and the capital, labor and materials costs of producing it. This policy is consistent with long-standing resource conservation policies of the state and federal governments and with the basic goals of Project Independence.
2. Maintain, and enhance where possible, the employment and economic activity levels of those communities involved in the production, processing and transporting of oil and gas.

A third constraint on the level of the royalty rate, which is applicable to both private and governmental landowners, would be a policy of attempting to increase the number of bidders for leases, and thus the competitiveness of the lease sale. This constraint is briefly discussed in section 3.3.

Although these policies are treated as constraints on the level of the royalty rate, they can also be treated as independent policy goals and trade-offs between these two goals and the wealth maximization goal evaluated. This approach, however, requires that the key policy-makers specify their views on the nature of the trade-offs that are acceptable to them and that some means of resolving differences of opinion with respect to the trade-offs be developed. Since these matters are a normal part of the political decision process, they are not considered here. Formulation of the problem in terms of constraints permits consideration of the trade-offs among the three goals should that be desired.[12]

3.1 Maximizing Oil and Gas Production from the Lease

As was shown in section 1.1, increasing the flat rate royalty to high levels--even as high as four- or five-sixths of gross revenue--substantially increases the landowner's wealth above that with the customary one-sixth royalty. However, one of the critiques of this conclusion was that high royalty rates will lead to premature abandonment of the well or field. Using the same simulation study as was used in the preceeding tables, the reserves losses in Table 4 rose to 8.5% and 21.6% when the flat rate royalty rose to four- and five-sixths, respectively. At a three-sixths flat rate royalty, the loss in reserves was 3.55%. Given the reservations with respect to the possible impact of sharply higher royalty rates on the level of investment in the lease expressed in section 2.2, the loss in reserves could be somewhat greater than the amounts in Table 4.

Given the conservation goal of maximizing the amount of oil and gas produced from each reservoir, such losses in reserves would be unacceptable. For the purposes of this paper, assume that the conservation policy is specified in terms of the following constraint: Royalty rate policies which are expected to reduce oil and gas reserves below the levels that are expected with a one-sixth flat rate royalty are unacceptable.

Given this policy constraint, flat rate royalties in excess of one-sixth of gross revenue would be politically unacceptable. It is, however, possible to increase the average royalty rate above one-sixth and still meet the above conservation policy constraint. This is done by adopting a two or more part royalty schedule similar to that in Table 5. The average royalty rates implied by this royalty schedule in Table 5 are in Table 6.

Table 5

Sample Two-Part Royalty Schedule
For Each Well on the Lease

Annual Oil Production*	Royalty Rate
0 to 10,000 bbl.	12.5%
Over 10,000 bbl.	66.7%

*10,000 bbl/yr is 27.4 bbl/day.

Table 6

Average Royalty Rate for Selected
Annual Production Rates*

Annual Oil Production	Average Royalty Rate
10,000 bbl.	12.5%
12,000	21.5
15,000	30.5
20,000	39.6
30,000	48.6
50,000	55.9
100,000	61.3
150,000	63.1
200,000	64.0

*Based on royalty schedule in Table 5.

The royalty rate on the first 10,000 barrels of oil produced in a year is 12.5% of gross revenue, with a 66.7% royalty rate being changed on 10,001st barrel and all subsequent production in the year. Thus, when production exceeds 10,000 barrels per year the average royalty rate rises--relatively rapidly at first and then gradually approaching 66.7% as production rises above 100,000 barrels per year (274 barrels per day). When oil production falls below 10,000 barrels per year, the low royalty rate makes it economic for the lessee to continue operating a well that would have to be abandoned if there were a flat rate royalty of, say, three-sixths. In general, when oil production is greater than 10,000 barrels per year for a given well, the lessee's marginal operating costs of producing each barrel of oil over 10,000 barrels are virtually zero; hence, a substantially higher royalty rate on production over 10,000 barrels in a year will not result in abandonment of the well.

The 10,000 barrels per year breaking point in the royalty schedule was only an example of a production rate that might be used for the breaking point. The actual rate of production to be used as the breaking point would depend upon the expected operating conditions and productivity of the lease, and the expected well-head price. Where expected costs are high, and/or well productivities and well-head prices low, a higher breaking point may be appropriate as might be another step in the schedule. For example, the royalty schedule could be that in Table 7, which implies the average royalty rates in Table 8. The rate of increase in the average royalty rate is substantially slower under this three-part schedule than under the two-part schedule in Table 5.

It is important to note that the higher royalty rates are applied to incremental rates of production and not to all production from the well. If the higher royalty rate applies to all production from the well when, say,

Table 7

Sample Three-Part Royalty Schedule
For Each Well on the Lease

Annual Oil Production	Royalty Rate
0 to 10,000 bbl.	12.5%
10,001 to 30,000 bbl.	25.0%
over 30,000 bbl.	75.0%

Table 8

Average Royalty Rate for Selected
Annual Production Rates*

Annual Oil Production	Average Royalty Rate
10,000 bbl.	12.5%
12,000	14.6
15,000	16.7
20,000	18.8
30,000	20.8
50,000	42.5
100,000	58.8
150,000	64.2
200,000	66.9

*Based on the royalty schedule in Table 7.

production is above 10,000 barrels in a year, the royalty schedule would provide an incentive for the lessee to hold production below 10,000 in a year when the well's productivity is somewhat, but not greatly, above 10,000 barrels in the year. By holding production below 10,000 barrels in the year, the lessee could avoid the higher royalty rate. It is strongly recommended that multipart royalty schedules be based on incremental production rates carrying the higher royalty rates, not all of the production from the well.

The author has computed the reserves and landowner lease bonus and royalty receipts for the lease used in Tables 1 through 4 using the two-part royalty schedule in Table 5. The oil reserves for the lease were calculated to be 21.59 million barrels and the lease bonus plus the present value of royalties was calculated to be $73.85 million. If a flat rate royalty of one-sixth had been specified in the lease contract, instead of the two-part royalty schedule, oil reserves would have been 21.59 million barrels (see Table 4) and the lease bonus plus the present value of royalties would have been $33.9 million (see Table 1). Thus, the sample two-part royalty schedule meets the conservation policy constraint while more than doubling the landowner's receipts by increasing them from $33.9 to $73.85 million.

The two-part royalty schedule in Table 5 is, of course, only an example. It is possible to construct reasonably optimal two or more part royalty schedules for any given set of leases depending upon the expected geological and operating conditions and well-head price of the oil. It is strongly recommended that any increase in the average royalty rate be accomplished by means of a multipart royalty schedule rather than by raising the flat rate royalty above the customary one-sixth of gross revenues.

3.2 Maintain, or Enhance, Employment and Economic Activity Levels

As was discussed in section 2, increasing the flat rate royalty substantially above the customary one-sixth of gross revenues will result in earlier abandonment of the field and a reduction in the total oil and gas production of the field. For example, with a four-sixths flat rate royalty, the lease in Tables 1 through 4 would be abandoned 26 years after the lease contract was signed, rather than 36 years later if the one-sixth flat rate royalty was used. Although the annual production rate in the 26th year is 308,000 bbl. (844 bbl/day) and the annual production rate in the 36th year is only 113,000 bbl. (310 bbl/day), it is none-the-less economic to operate the lease for an additional ten years at the customary one-sixth royalty rate. This means that the lease will continue to provide employment at about the same rate as in the 26th year and contribute accordingly to the local economic activity.

At the lower royalty rate, it is more likely that secondary recovery, pressure maintenance, in-fill drilling, and salvage perforation operations will be commenced or engaged in during the latter years of the field's life. These investment activities all contribute to maintaining, or even enhancing, employment and economic activity levels in the local community and the state. Property, sales and other tax revenues of the local community will be maintained for a longer period of time, and the relatively long-lived public service, utility and housing facilities of the community will be used for a longer period of time more closely approximating their useful economic lives (30 to 50 years for most buildings and utility systems).

Where maintaining the employment and economic activity levels of the local community is a fundamental policy constraint on the lease terms, it generally is imperative that flat rate royalties above the customary one-sixth of gross revenue be avoided. However, it is possible--as with respect to the previous policy constraint--to construct a multipart royalty schedule that will attain this policy objective while, at the same time, increasing substantially the landowner's lease bonus and royalty receipts. An example of such a royalty schedule is the two part royalty schedule in Table 5.

If there is a reasonable prospect that secondary recovery projects might be initiated by the lessee at some time during the life of the lease, this policy objective implies that the landowner may wish to provide in the lease terms a separate royalty schedule for secondary recovery projects. The royalty schedule applying to secondary recovery projects would provide for lower average and marginal royalty rates, especially for relatively low rates of production. Providing this secondary recovery royalty schedule would increase the probability that secondary recovery projects would be initiated--thus enhancing employment and economic activity levels in the community--and eliminate the uncertainties and costs associated with lease provisions that permit renegotiation of royalty rates. It is the author's understanding that the costs of renegotiating royalty and override rates have led to abandonment of potentially promising secondary recovery projects before they could be initiated.

3.3 Increasing the Number of Bidders for Leases

One criticism of the competitive bonus bidding procedure used by the federal government and most state government to determine which potential lessee is to receive a given lease is that it favors large firms with ready access to large, internally generated, cash flows and to the capital markets over smaller firms. Since a higher average royalty, in general, implies a lower bonus bid for the lease (see Table 1), increasing the average royalty rate by using a multipart royalty schedule may make the bidding process more competitive. It may also make it possible for relatively small, locally based, oil companies formed by residents of the state or community to bid for leases in competition with larger firms from other areas or nations. Reducing the amount of the bonus bid may also be desirable in periods of capital stringency.

Both a higher flat rate royalty and a multipart royalty schedule can attain this objective of reducing the amount of the bonus bid. Since a higher flat rate royalty fails to meet the constraints on royalties discussed in the preceeding two sections, it is recommended that multipart royalty schedules be used to increase average royalty rates and thus reduce the maximum bonus bid that a potential lessee would be willing to pay.

FOOTNOTES

1. The definitions of reserves and original-oil-in-place used by the American Petroleum Institute are used through this paper.

2. The difference between the delivered price and the cost of transporting the oil is the principal determinant of the well-head price for the oil where competitive refiners buy the oil at the well-head.

3. Other public policies may imply that the present value of the lease be held to some positive value--for example, to obtain as quickly as possible specified employment levels.

4. The lease contract also generally requires that the lessee pay a per-acre rental on the land under lease, with the royalties replacing the rental when the former is larger. In most cases, the rentals are at nominal levels compared to the potential value of the land.

5. Whether competitive bonus bidding with the usual number of bidders for an oil lease actually accomplishes this objective is not discussed in this paper.

6. The relationship between the bonus bid and the royalty rate is almost linear because of the nearly proportionate reduction in the lessee's revenues with a higher royalty. Strict proportionality does not hold because a higher royalty rate generally implies an earlier abandonment of the lease. See section 2.1 for more on this point.

7. An example would be the State of Texas where <u>ad. valorum</u> severance taxes on petroleum make up as much as half, or more, of the tax revenues of many of its political subdivisions.

8. The Federal Energy Administration's definition of the term "new-oil" is implied here.

9. This has occured since 1973 in several of the oldest producing areas of the continental United States since oil from long abandoned wells receives the FEA's new-oil price.

10. It exceeds $58 per barrel because the royalties are discounted (i.e., Table 1 contains the present value of the royalties) and the reserves are not discounted.

11. This is especially the case in periods where capital is relatively scarce and expensive.

12. By changing the policy constraints and recalculating the impacts of the leasing policy on the landowner's wealth, oil reserves, and employment and economic activity levels, the effects of alternative policy combinations can be determined. The political decision makers can then rank the policy combinations and resolve the differences in their ranking through the normal democratic political process.

Appendix G

EXPLORATION EXPENDITURE BIDDING FOR EXPLORATORY LEASES ON LANDS OWNED BY THE STATE OF ALASKA

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January 1977

Although reserves of several billion barrels of oil and several trillion cubic feet of natural gas have been discovered and proven on the North Slope, a substantial field located in the Umiat area, and large reserves produced for almost two decades in the Cook Inlet area, very large areas of the State of Alaska are believed to have geological conditions that are suitable for the occurance of commercially exploitable deposits of petroleum. Virtually all of these attractive exploratory areas are untested by exploratory drilling. These prospective areas are both offshore and onshore, and include remote inland areas of the State. They present some of the most difficult and technologically challenging operating conditions in the world for petroleum exploration and for the development of commercial fields should any be discovered. Furthermore, many of these areas have fragile ecological systems that recover relatively slowly from the effects of environmental stress. Yet, these areas in Alaska provide one of the few remaining areas of the United States where oil and gas discoveries of significant magnitude are reasonably likely. Because of the exceptionally great uncertainties with respect to the geological, technological, environmental and economic conditions associated with exploring and producing these tracts, it is recommended in this paper that the State of Alaska investigate the competitive exploration expenditure bidding procedure for leasing these lands.

The competitive exploration expenditure bidding procedure for leasing government lands for petroleum exploration is based on selecting the winning bidder for each exploration lease on the basis of the amount of money the firm or joint venture is willing to spend on exploring the lease. Each exploration lease would normally consist of several tracts of land that are believed to be geologically related. Accompanying each exploration expenditures bid would also be a description of the nature of the exploration activities the firm proposes to undertake with the funds in its bid. These exploration activities would include both exploration of the leased area for petroleum and assembly of the necessary data for an environmental impact assessment of development of the lease should it prove to be productive. The initial exploration plan would be subject to mutually acceptable modifications should exploration of the lease indicate that a change would be in the best interests of both parties to the lease. Upon completion of the exploration program, if one or more of the tracts proves to be productive, the lessee would be permitted to select one of the tracts for a development and production lease to be awarded upon completion of the environmental impact assessment process. The State can offer for competitive bidding some or all of the remaining tracts of land in the exploration lease. All the geological and other data developed by the exploration lessee would be provided to the potential bidders for these leases. If the first exploration lease on the tracts fails to identify commercially attractive oil or gas reserves, one or more additional competitive exploration expenditure lease sales can be held if firms in the industry are still interested in bidding for the lease.

The basic objectives of this exploration expenditure bidding program are:

1. The data provided by the exploration lessee should reduce substantially the levels of risk and uncertainty regarding the geological, technological, environmental and marketing conditions of the tracts to be offered for development and production leases. This data should, on the average, substantially increase the bids on the tracts offered for development and production leases where the initial exploration has either proven the existence of commercially exploitable petroleum deposits or indicated that there is a reasonable probability of their occurance.

2. The data provided the exploration lessee should permit the State to better determine

   a. the timing and extent of its future lease sales, so that the leases offered will more closely approximate the ability of the industry to explore, develop and profitably produce additional reserves, and

   b. the optimal lease terms for the development and production leases with respect to royalty rates, conservation and environmental protection regulations, etc.

3. The data provided by the lessee would permit the State to prepare an environmental impact assessment of the proposed development and production leases and would enhance the development of mitigating technologies and procedures based on far more data than would be available if the exploratory lease had not preceeded the offering of development and production leases.

4. The very nature of the exploratory lease's terms and the program of exploration activities which the lessee has agreed to undertake would prevent the speculative holding of leases by private firms in hopes that the exploratory activities of others will increase their value.

5. The industry's capital requirements are reduced and their expenditures on exploration and research increased since none of the industry's expenditures are diverted, by means of a lease bonus, from exploring the tracts contained in the exploration lease.

6. The data provided by the lessee would facilitate inclusion of specific terms in development and production leases with respect to unitized operation of tracts covering the same reservoir. These unitization terms could be included in the lease contract at the time the tracts are offered for development and production leases.

The principal disadvantage of the exploration expenditure lease bidding procedure, which may be an advantage given the projected crude oil surplus in District V for the next decade, is that it may lengthen the time between the decision to lease an area and its development by one or more years since development and production leases are not awarded until after all of the contracted exploration is completed. This procedure is intended to avoid the necessity of almost immediately offering the tracts adjacent to a discovery at a "drainage" sale. Another disadvantage of this procedure is that tracts on which the industry may have been willing to make multimillion dollar bonus bids before an exploration lease was issued may become worthless to the State if the exploration shows them very unlikely to contain commercially attractive oil and gas reserves. Whether this loss in lease bonus revenues is more than offset by higher lease bonus and royalty revenues on the tracts of land which the exploration lease has identified as likely to contain commercially attractive reserves is an empirical matter; however, the author believes that on balance the State would benefit substantially from using the exploration expenditure lease bidding procedure and bearing the risks associated with unexpectedly unproductive leases.

Central to the exploration expenditures lease bidding procedure is determination of the number and location of the tracts to be offered as an exploration unit. Three principal considerations enter into determination of the number of tracts in the exploration lease:

1. The tracts in the exploration lease should be geologically related so that intensive exploration, including the drilling of exploratory wells (some in locations specified in the lease and some in locations to be mutually agreed upon by the lessee and the State after drilling of the specified wells), will develop the kind and amount of data necessary

to reduce substantially the uncertainty about the potential petroleum resources of all or most of the tracts in the unit. For example, the tracts making up an exploration lease may be all of the tracts over and immediately adjacent to a suspected geological feature. If the suspected structure is relatively large, two or more exploration leases may be established. In addition, the number of tracts to be included in an exploration lease should not be so small as to result in the winning bid's being sufficiently large to reduce the expected marginal benefits from the last dollar spent on exploration to less than one dollar. To avoid this situation and situations where the initial exploration results indicate little likelihood of discoveries from more exploration, the lessee can be required to pay directly to the government any exploration funds which cannot--in the opinion of the lessee and the State--be economically spent on exploration or research.

2. The economic constraint on the number of tracts to be included in an exploration lease is based on the State's estimate of the _ex. ante._ economic rents inherent in the tract with the greatest _ex. ante._ economic rents, since the lessee is permitted to select only one of the tracts for a development and production lease upon completion of the exploration program. Thus, determining the number and configuration of the tracts to be included in an exploration lease requires that the State obtain some geological and economic data on the tracts prior to the lease sale. The best way to obtain this data appears to be to request all firms in the industry to make a preliminary nomination of the groups of tracts that they believe should form the exploration leases. Prior to the lease sale, the interested companies--singly or in groups--would be given permits to perform geological and geophysical

studies of the proposed exploration leases. These studies would provide the information necessary for each company or joint venture to determine the amount of exploration expenditures they will bid on each lease and the nature of their proposed exploration program. By then requesting each company or joint venture to nominate formally the tracts to make up each exploration lease and to provide a confidential report indicating the geological and economic reasons why it grouped a specific set of tracts into one exploration unit, the State's geologists, petroleum engineers, and economists would likely obtain sufficient information to specify the tracts to be included in each exploration lease. If necessary, the State could contract with service companies for additional information.

3. It is recommended that the lessee be required to prepare a preliminary environmental impact assessment for the development of those tracts which exploration has shown to be productive, or likely to be productive, of petroleum; or a full environmental impact statement where it is appropriate. To reduce the costs of the environmental impact assessment--which must be paid for from the lessee's evaluation of the <u>ex. ante</u>. rents inherent in the best tract in the exploration lease—wherever geologically feasible, the area covered by the exploration lease could be restricted to one, or a few, environmental and ecological settings. To further hold down these costs, the State may wish to require all of the winning bidders for exploratory leases to finance joint studies of those environmental and ecological factors that are common to two or more exploration leases.

Where the prospects for discovering commercial quantities of petroleum in one of the tracts of a given exploration lease are relatively minimal or exceptionally uncertain, or where a substantial technological advance will be required to profitably operate the lease, transport the oil or provide the required degree of environmental protection, it may be necessary to permit the winning bidder to select two or more tracts from the exploration lease for development and production leases. Under these conditions, the <u>ex</u>. <u>ante</u>. economic rents inherent in the best tract may not be adequate to bring forth adequate exploration or research to meet the objectives of the leasing program. Identifying which exploration leases will require permitting the lessee to select two or more of the tracts for development and production leases requires the State to acquire a geological, economic and environmental data base adequate to estimate the <u>ex</u>. <u>ante</u>. economic rents inherent in the best tracts in the area of the exploration lease, and the costs of exploring it and preparing the required environmental impact assessment.

The competitive research expenditure bidding procedure determines the winning bidder for a given exploration lease by awarding the lease to the firm, or joint venture, contractually agreeing to spend the greatest amount on geological and geophysical exploration; exploratory well drilling; research and development relating to environmental protection, production and transportation facilities for the productive tracts; and other research activities the State and the lessee may agree are appropriate to increase the economic value of the lease or to preserve its environmental and ecological values. Each bid should be accompanied by the lessee's formal acceptance of the State's specifications for the environmental impact assessment for development of the productive tracts and for future exploration of those tracts for which the State believes additional exploration or research is appropriate. It should also include the lessee's agreement to release in a timely fashion and in a manner specified by the State all information generated as a result of the agreed upon exploration and research expenditures.

The lease bid should include a preliminary description of the geological and other exploration and research work that the bidder will perform if its bid is accepted. Where one or more bids are within, say, five or ten percent of the highest bid, the bidding procedure could specify--if the enabling legislation or regulations were to permit it--that the State could negotiate with all these bidders with respect to the exploration program and award the lease to the bidder proposing the "best" exploration program. The criteria for determining the "best" exploration program should be made public prior to the exploration lease sale. In any event, the winning bidder would be required to finalize the description of its exploration program and obtain the State's approval before the lease would be formally awarded.

The description of the work to be performed would include at least the following major points:

1. The geological and geophysical program for the tracts, including a description of the geophysical work already performed. Geological and geophysical expenditures made prior to the lease sale should not be included in the amount of exploration expenditures in the bid.
2. The initial exploratory drilling program if geophysical work prior to the lease sale was adequate to specify such a drilling program. The description of the drilling program would include the preliminary timing, location, and formation objectives of each well; an explanation of why this drilling program will provide adequate information to evaluate the most prospective tracts; and a description of the lessee's environmental protection program for its exploratory drilling program.
3. The general specifications of the anticipated follow-up geophysical and drilling program, if any.

4. A description of the lessee's research and development program with respect to exploration, production and transportation technologies (including specific design criteria where applicable) and to environmental protection facilities and procedures applicable to the exploration lease or to future development and production leases.
5. Descriptions of other activities which the bidder believes to be appropriate for research relating to these tracts.

The State could specify a range of terms, say three to five years, for the exploration lease at the time the lease sale is announced. The winning bidder would then be permitted to specify the length of time for the exploration lease. The lessee, however, should not be permitted to terminate the lease prior to its expiration (i.e., upon making a discovery on one tract) without permission of the State. Expenditure of the amount bid and completion of the contractually agreed upon elements of the exploration program would, naturally, terminate the lessee's work under the exploration lease and the lease could then be terminated by mutual consent even if the entire term has not yet elapsed. Should the lessee fail to complete the contractually agreed upon exploration program prior to the end of the term of the lease, as might occur due to unexpectedly bad weather or unanticipated equipment breakdowns, the State should have the option of terminating the lease upon receipt of any unexpended funds or it could extend the term of the lease to permit the lessee to complete the exploration program. If the lessee were to be unable to complete the contractually agreed upon exploratory program within the exploration expenditure bid amount, the lessee should be required to fund its completion or to forfeit its right to select one or more tracts for a development and production lease. Upon completion of the agreed upon exploration program to the satisfaction of the State and termination of the exploration lease, the lessee would be able to select the tract, or tracts, upon which it is to receive a development and production lease, with the awarding of this lease to be subject to acceptance of the lessee's environmental impact assessment by the appropriate agencies.

The above descriptions provide only a general outline of the nature of an exploration expenditures bidding program intended to provide the State of Alaska with the benefits which it can obtain from the resulting reductions in the uncertainties regarding (1) the economic value of the tracts in the exploration lease and (2) the environmental and ecological impacts of developing those tracts which are shown to be productive of petroleum. Formulation of a practical competitive exploration expenditures bidding program would require far more detailed and specific legal, geological, engineering, environmental, economic and administrative analyses and review by the State, industry trade associations, and individual companies than has been provided in this paper.

Appendix H

Computing the _Ad_ _Valorem_ Charge (AVC)

Table H-1 shows how the _ad_ _valorem_ charge is figured. It begins with a forecast of daily flows. In this case they are taken from the Van Poollen report, "Prediction of Reservoir Fluid Recovery, Sadlerochit Formation, Prudhoe Bay Field," January, 1976. These figures do not apply to separate leaseholds and, of course, would have to be broken down in application.

Table H-1 assumes that the _ad_ _valorem_ charge is at a rate of 20 percent, levied on the base of the discounted cash flow (DCF).

This whole process is quite mysterious to many people and so we are laying it out step by step.

Note first that a 20 percent rate is not as high as it seems at first, because it is "capitalized." That means that the expectation that the charge will be levied over the next 25 years reduces the present value of the DCF. It reduces it in exactly the same way that increasing the basic discount rate from 8 to 28 percent would reduce it. The interest rate is basically a toll for moving through time, and that is exactly what the _ad_ _valorem_ charge is as well.

Comparing columns 4 and 5 of Table H-1, the effect of capitalizing the _ad_ _valorem_ charge is that the discounted cash flow is only about three times as high as the current year's cash flow in the early years. In the later years the two values come even closer together.

A high rate does not take more income than there is because if it did there would be no base, and if there were no base there would be no charge. This dog-chasing-tail process balances out at a point where the high percentage rate and the low DCF base combine to produce a middling sort of figure. Table H-1 shows exactly how the base is reduced and the charge arrived at.

A high percentage rate does not cause early shutdown because the base drops over time. Table H-1 shows that it drops from \$16.1 billion down to \$.1 billion, the second figure being six-tenths of 1 percent of the initial one.

The DCF base is arrived at by discounting future cash flows at 28 percent per annum compounded. For anyone not conversant with this process, the last figures in columns 4 and 5 are the easiest place to begin. A cash flow of \$.14 billion is due on December 31 of the year. The value of that on the preceding January 1 is the sum which will grow at .28 percent interest to equal \$.14 billion. That sum is \$.109 billion, because

$$.140 \div 1.28 = .109$$

The last two columns, 11 and 12, indicate something about the orderliness of this process. The lessee always gets 8 percent of the current year's DCF and the lessor always gets 20 percent of it. The split between them, then, is always 2½ to 1, that is, 20 ÷ 8.

The 8 percent figure is known as the capitalization rate. The split between the lessor and the lessee always depends basically on the relationship between the AVC rate and the capitalization rate. The effect of the 20 percent AVC rate would be considerably offset by the adoption of an equally high capitalization rate. Alaska uses an 18 percent rate in computing the Alaska reserves tax, a figure which we believe is too high. Just for illustration, if the AVC rate were 20 percent and the cap rate were 20 percent, then the split would be 1 to 1, or 50-50.

The implicit assumption is that the lessee has paid $16.1 billion to buy the lease on January 1 of year 1. He is earning 8 percent on that investment under conditions of very low risk over a 25-year period. He is not earning 8 percent on all of it for 25 years because he recovers some of it each year. He is earning 8 percent on the unrecovered balance each year. The unrecovered balance is the amount shown in column 5, that is, the discounted cash flow as of each current year.

The last barrel lifted is charged 25 times at a rate of 20 percent before being lifted. This might seem like an awful lot but it turns out to be much less, because what is taxed in year 1 is not the value of the barrel in year 25 but the discounted cash value of the barrel, discounted back 25 years at 28 percent per year. A barrel of oil to be sold for $8 at the end of 25 years has a present value of 1.7¢; and 20 percent of 1.7¢ is .3400 of a cent. Therefore, the fact that the barrel is charged 25 times at 20 percent does not mean that the sum of the charges will amount to a great deal.

There will be an incentive to accelerate production but that would require more capital, lasting over the full life production and only used part of the time during the early flush years. To estimate the effect we have to look at the whole process over 25 years and not just at one barrel. Appendix I does this and the finding is that production is not very sensitive to large increases in the interest rate or the <u>ad valorem</u> charge.

All this assumes that the existence of the last barrel is known over 25 years. In fact it may not be. The greatest weakness in this proposal, in my opinion, is its inadequate collection of revenue from deposits whose presence is concealed or unknown until shortly before they are produced.

Lacking from Table H-1 is a statement of what would happen in the years preceding year 1, which is here treated as the year when cash flow begins. In practice, there is a substantial number of years when DCF is positive and quite large before there is any production. AVC would be raising revenue all during this period. From the lessee's point of view this would be tolerable since all the signs in column 8 would be plus: that is, the value of the leasehold interest would be rising each year as we move nearer to production.

Table H-1

An <u>Ad</u> <u>Valorem</u> Charge of 20%, Showing Capitalization of Charge into DCF

(1) Year n	(2) Daily Flow	(3) Yearly Flow (2) x 365	(4) Cash Flow @ $8/B	(5) DCF	(6) AVC .20xDCF .20 (5)	(7) Cash to Lessee CF-AVC (4)-(6)	(8) True Depletion or Change in DCF	(9) State's Share of Cash Flow AVC/CF (6)/(4)	(10) Income to Lessee CF-AVC Less True Depletion (7)+(8)	(11) Return on Lessee Investment (10)/(5)	(12) ~~Avg.~~ avg. Income to Lessee (6)/(10)
	MM B/D	MM B/Y	MMM $/Y	MMM $	MMM $	MMM $	MMM $	%		%	
1.	1.40	511	4.1	16.1	3.21	.88	+ .41	79	1.28	.08	2.5
2.	1.80	657	5.3	16.5	3.30	1.96	- .61	63	1.34	.08	2.5
3.	1.80	657	5.3	15.9	3.18	2.07	- .82	61	1.26	.08	2.5
4.	1.80	657	5.3	15.1	3.01	2.25	-1.02	57	1.23	.08	2.5
5.	1.80	657	5.3	14.1	2.82	2.42	-1.31	54	1.11	.08	2.5
6.	1.80	657	5.3	12.8	2.55	2.72	-1.69	48	1.02	.08	2.5
7.	1.80	657	5.3	11.1	2.21	3.04	-2.16	42	.876	.08	2.5
8.	1.31	478	3.8	8.9	1.78	2.04	-1.31	47	.730	.08	2.5
9.	1.10	401	3.2	7.6	1.52	1.69	-1.11	47	.584	.08	2.5
10.	.91	332	2.7	6.5	1.30	1.37	- .818	49	.555	.08	2.5
11.	.89	325	2.6	5.7	1.13	1.46	-1.02	44	.438	.08	2.5
12.	.87	318	2.5	4.6	.929	1.61	-1.26	37	.350	.08	2.5
13.	.58	212	1.7	3.4	.677	1.02	- .730	40	.292	.08	2.5
14.	.48	175	1.4	2.66	.531	.876	- .660	38	.216	.08	2.5
15.	.35	128	1.0	2.00	.400	.613	- .450	39	.163	.08	2.5
16.	.24	88	.70	1.54	.310	.380	- .263	44	.117	.08	2.5
17.	.17	62	.50	1.27	.254	.234	- .140	51	.094	.08	2.5
18.	.16	58	.46	1.13	.228	.234	- .146	48	.088	.08	2.5
19.	.15	55	.44	.984	.196	.234	- .163	45	.071	.08	2.5
20.	.13	47	.38	.821	.163	.220	- .146	43	.068	.08	2.5

(To be continued)

Table H-1 (continued)

(1) Year n	(2) Daily Flow MM B/D	(3) Yearly Flow (2) x 365 MM B/Y	(4) Cash Flow @ $8/B MMM $/Y	(5) DCF MMM $	(6) AVC .20xDCF .20 (5) MMM $	(7) Cash to Lessee CF-AVC (4)-(6) MMM $	(8) True Depletion or Change in DCF MMM $	(9) State's Share of Cash Flow AVC/CF (6)/(4) %	(10) Income to Lessee CF-AVC Less True Depletion (7)+(8)	(11) Return on Lessee Investment (10)/(5) %	(12) Income to Lessee (6)/(10)
21.	.12	44	.35	.672	.134	.216	- .164	38	.052	.08	2.5
22.	.10	36	.29	.508	.102	.188	- .149	35	.039	.08	2.5
23.	.08	29	.23	.359	.073	.146	- .117	31	.029	.08	2.5
24.	.06	22	.18	.225	.044	.135	- .117	26	.018	.08	2.5
25.	.05	18	.14	.109	.022	.118	- .109	16	.009	.08	2.5

Technical Notes by Column

(2) Daily flows in barrels from Run #18 in "Prediction of Reservoir Fluid Recovery, Sadlerochit Formation, Prudhoe Bay Field," January, 1976, Table XIX. Gas recovery not included. Rounded to two places. The rounding results in minor discrepancies in the body of the table.

(3) We convert barrels per day to barrels per year. We make no adjustment for shutdowns or other factors.

(4) We multiply the number of barrels by $8 each. This is purely to show a method, and the price is assumed constant over 25 years without implying that that is an accurate forecast. We also assume that current operating expenses are deducted.

(5) The figure at the top of this column, 16.1, is arrived at by first discounting each year's cash flow in column 4 by the number of years that it follows January 1 of year 1 and then cumulating them. That is, we discount 4.1 over one year, assuming that the 4.1 is received on December 31. Then we discount 5.3 over two years and add that to the cumulative total. Then we discount the next 5.3 over three years and so on. We finally get down to .14 received at the end of year 25, discount that over 25 years and add that to the total, bringing us to 16.1.

The second figure, 16.5, is arrived at by the same process, except that now we omit the initial 4.1 and then we discount the first 5.3 over one year instead of two and so on down to .14 at the end of year 25, which we now discount over 24 years instead of the initial 25.

When we finally get to the bottom of column 5, the last figure, .109, is arrived at simply by discounting .14 over one year.

As we run down column 5, DCF changes as a result of two things. First, we chop off a year; but second, all the later years move one year closer to the present and therefore rise in present value by 28 percent. The net result is normally a decline in DCF, but not in the first year. Note that if we went back to the years before 1, DCF would always be rising at 28 percent per year, of which 20 percent would go to the State and 8 percent to the lessee.

(6) AVC is always 20 percent of DCF.

(7) This is what the lessee gets after paying the charge.

(8) This is the change in DCF from year to year. It is what economists call "true depletion," that is, the decline in the value of the asset. Note that it is much less in the early years than the cash flow (column 4). This is because production today does not reduce

production next year but, rather, reduces production many years in the future.

Again note that this column might be extended upwards into years before number 1 and all the figures would be positive.

(9) This is the State's share of the cash flow. It is less than the State's share of income because income is lower than cash flow, as we see next.

(10) The lessee's income is the cash he receives minus the decline in his wealth.

(11) The lessee's income is always 8 percent of the DCF. DCF is also the unrecovered balance of his initial investment of $16.1 billion on January 1 of year 1. The lessee always gets 8 percent of that figure and the lessor gets 20 percent, so that:

(12) The lessor always gets 2½ times the lessee's income.

Appendix I

Sensitivity of Discounted Cash Flow (DCF) to Production Rates and Interest Rates, Sadlerochit Formation

Table I-1 shows two alternative schedules of the flow of production from the Sadlerochit Formation. These are taken from the Van Poollen report, "Prediction of Reservoir Fluid Recovery, Sadlerochit Formation, Prudhoe Bay Field," Tables XVII and XIX. Both runs result in almost exactly the same ultimate recovery. The difference is that Run 18 starts faster and ends slower than Run 16. Run 18 would require a greater investment in lessee's capital to allow the faster starting rate of production to occur. This is compensated by the higher present value. Table I-2 shows the increase in present value or DCF at different rates of discount. Several points stand out.

DCF is sensitive to production rates. The gain in DCF from choosing Run 18 over Run 16 is a present value increment of $5.4 billion at a 10 percent rate of discount. This is the maximum gain: it declines in both directions from 10 percent. However, it does not decline very sharply and is surprisingly insensitive to the rate of interest.

DCF is sensitive to the discount rate. For Run 18 it declines from $47.8 billion down to $16.1 billion as we go from a 3 percent to a 28 percent discount rate.

Run 16 is more sensitive to the discount rate than is Run 18. This is because Run 16 is slower and therefore more weighted towards the future, where discount factors are more sensitive to the choice of a discount rate.

The third row, which is Run 18 minus Run 16, is not very sensitive to the discount rate. This last point is quite significant. The amount of capital we can justify investing to speed up the flow of production is limited by the gain in DCF that results. Normally, with other kinds of investments, a higher rate of discount means a lesser gain from any investment that increases future production. In this case it means a greater gain, at least until the discount rate reaches 10 percent, after which the gain tapers off again.

Note how this bears on the concern that a higher ad valorem charge (AVC) would cause the last barrel of oil to be extracted too rapidly. When the discount rate rises above 10 percent, the addition of an ad valorem charge will slow down rather than speed up production by limiting the number of wells that may be drilled.

There appear to be two countervailing forces at work here. As we raise the discount rate both series of DCF's become smaller, which tends to bring them closer together, but Run 16 is more sensitive to the discount rate, which tends to pull them farther apart. Between 3 and 10 percent, the second force overpowers the first, and above 10 percent vice versa.

We leave further investigation of this interesting phenomenon to future study. The present point is that the application of an ad valorem charge would not contain much net bias either in the direction of speeding up or slowing down production.

Another important implication is that we may live in a world of uncertainty about future interest rates, but that does not prevent our scheduling flows with some assurance that our scheduling will be optimal in case future interest rates change. Because future interest rates may change a good deal without changing the optimal application of capital.

Table I-1

Runs 16 and 18 from the Van Poollen Report

Year	Run 16 MMB/D	Run 18 MMB/D
1	1.4	1.40
2	1.2	1.80
3	1.2	1.80
4	1.2	1.80
5	1.2	1.80
6	1.2	1.80
7	1.2	1.80
8	1.2	1.31
9	1.2	1.10
10	1.2	.91
11	1.2	.89
12	1.2	.87
13	.99	.58
14	.75	.48
15	.56	.35
16	.47	.24
17	.35	.17
18	.27	.16
19	.22	.15
20	.17	.13
21	.13	.12
22	.11	.10
23	.10	.08
24	.08	.06
25	.07	.05
26	.05	--

Table I-2

Present Values at Different Rates of Discount,

Runs 16 and 18, Van Poollen Report

Discount Rate	.03	.05	.08	.10	.15	.20	.28
Run 18	47.8	42.3	35.6	32.7	25.6	21.0	16.1
Run 16	43.5	37.5	30.7	27.3	21.0	16.8	12.6
Run 18-Run 16	4.3	4.8	4.9	5.4	4.6	4.2	3.5
Run 18/Run 16	1.098	1.127	1.160	1.196	1.22	1.25	1.28

Appendix J

The Future Shift Effect

The object here is to use simple mathematical models of some generality, to show the general point. For a total treatment we need one model of complete generality (which is attached at the end, but not recommended for light reading). We would also need several specific models based on actual decline paths. We have not undertaken the second, but our second model is tolerably near the actual runs predicted for the Sadlerochit Formation.

Model One

Model One assumes constant ultimate recovery = \$A, recovered at an even flow of $\frac{A}{n}$ over $\underline{n}$ years. We may reduce $\underline{n}$ by investing more capital. \$B is a (hypothetical) sum that it would take to build capacity to recover A in one year; so actual capital is $\frac{B}{n}$.

$$DCF = \frac{A}{n}\,\frac{1-e^{-in}}{i} - \frac{B}{n} \tag{J-1}$$

Now we impose a royalty at the rate $\underline{r}$. The new DCF is reduced. We label this new DCF after royalty as σ (sigma).

$$\sigma = \frac{A}{n}\,(1-r)\,\frac{1-e^{-in}}{i} - \frac{B}{n} \tag{J-2}$$

Now we divide σ by DCF. If the royalty is neutral it will reduce the DCF of all schedules by the same percentage, so the best schedule before royalty is the same as the best one after royalty.

$$\frac{\sigma}{DCF} = \frac{A(1-r)(1-e^{-in}) - Bi}{A(1-e^{-in}) - Bi} \qquad \text{(J-3)}$$

J-3 can easily be shown to be an increasing function of n. This means that σ as a percentage of DCF is higher for the slower schedules of production. This has to shift the optimal production plan to a longer, slower schedule.

Cost recovery alleviates but does not eliminate the bias. Let's assume the lessee can recover his capital, $(\frac{B}{n})$, by straight line depreciation (this is actually faster than true depreciation, and moves a little in the direction of accelerated write-off).

Let π = DCF after royalty with capital recovery.

$$\pi = \frac{A}{n}\,\frac{1-e^{-in}}{i}\,(1-r) - \frac{B}{n}\left[1-r\,\frac{1-e^{-in}}{i}\right] \qquad \text{(J-4)}$$

$$\frac{\pi}{DCF} = \frac{A(1-e^{-in})(1-r) - B(i-r(1-e^{-in}))}{A(1-e^{-in}) - Bi} \qquad \text{(J-5)}$$

J-5 can also easily be shown to be an increasing function of n, although less so than J-3.

Model Two

Model Two addresses the same question as Model One, but in an incremental instead of a total way. We want to know the value of adding a well to a given number already planned or existing. The last well adds to flow for 12 years, and then reduces it for 12 years by the same amount. It simply advances its production 12 years. This resembles the matter of going from Run 16 to Run 18 in the Van Poollen report (our Appendix I).

Let F be yearly well capacity, in dollars.

$$\text{Gross gain} = F\left(\frac{1-e^{-12i}}{i}\right) \qquad \text{(J-6)}$$

$$\text{Loss} = F\left(\frac{e^{-12i} - e^{-24i}}{i}\right) \qquad \text{(J-7)}$$

$$\text{Net gain} = F\left(\frac{1-2e^{-12i} + e^{-24i}}{i}\right) \equiv F\theta \qquad \text{(J-8)}$$

We label the expression in brackets as $\underline{\theta}$.

The value of $\underline{\theta}$ depends on $\underline{i}$, the rate of interest. Some values are given here:

i:	.06	.10	.13	.16
θ:	4.167	4.640	4.546	4.325

The value of θ is not very sensitive to the rate of interest. The net gain is about $4\frac{1}{2}$ times the yearly cash flow over a wide range of interest rates. This is the net gain from investing in a new well. Cf. Appendix I, where DCF is not very sensitive to interest rates.

It is clear that if we take a cut of F by a royalty, the gain of the new well is correspondingly reduced to:

$$\text{Net gain less royalty} = F\theta(1-r) \qquad \text{(J-9)}$$

If we let cost be recovered, there is still a decline in the net gain:

Net gain less royalty plus cost recovery =

$$F\theta - r\left[F\theta - \frac{C}{12}\,\frac{1-e^{-12i}}{i}\right] \qquad \text{(J-10)}$$

The expression in brackets is positive, because

$$C < F\theta \text{ and } \frac{C}{12}\,\frac{1-e^{-12i}}{i} < C$$

$\therefore$ (J-10) $< F\theta$

$\therefore$ the charge reduces investment and slows recovery.

There are several other routes to the same conclusion, which we omit. But specifically, if we have the lessee maximize his internal rate of return, the effect of royalties and profit sharing is the same, and the math is easier.

Another reason for deferring production is expected higher field prices, and/or expected lower real costs. Royalties exaggerate this motive. Compare J-1 and J-2, as the value of A rises while B remains the same. It is obvious by inspection that the royalty in J-2 gives more leverage to the constant $\frac{B}{n}$, so that

$$\frac{\frac{d\sigma}{dA}}{\sigma} > \frac{\frac{d(DCF)}{dA}}{DCF} \qquad \text{(J-11)}$$

This is most obvious when $\sigma = 0$ and DCF > 0. It can be shown to be true for all higher values of $\underline{\sigma}$ as well.

Appendix II

By William Vickrey and Michele Consigny*

Proof that an income tax using true depreciation is intertemporally neutral

Let $A(x)$ be a (continuous) cash or service stream bought for $C(0)$, 0 being the time of purchase and x the time of payment, n being the date of maturity or final payment. Let $P(x)$ be the present value at time 0 of a payment of \$1 at time x. The instantaneous short term rate of interest at time x is then $h(x) = -\frac{1}{P}\frac{dP}{dx}$. (The annual rate of interest is $i = e^h - 1$.) $C(y)$, the value at time y of the remaining payments from y to n, is then given by $P(y)\cdot C(y) = \int_y^n P(x)\cdot A(x)\,dx$. (1)

The depreciation in capital value at time y is then obtained from (1) by differentiating with respect to y:

$P\frac{dC}{dy} + C\frac{dP}{dy} = -P(y)\cdot A(y)$, and by solving for the depreciation, $\frac{dC}{dy}$ we get $D(y) = -\frac{dC}{dy} = A(y) + \frac{C}{P}\frac{dp}{dy} = A - hC$ (2)

Now let a tax be imposed at a rate $t(y)$ on the net income after depreciation $Y = A - D$, so that the tax is $t(y)\,[A(y) - D(y)]$ and the net receipts after tax are then $N = A - t(A-D) = A - thC$. Then there exists a private (2a) discount function $R(y)$, such that for any asset with a stream of payments $A(y)$, the current value of the asset can be obtained equally from discounting the gross payments A with the public discount function P, or the net proceeds N

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* Again, credit is hard to allocate precisely. Miss Consigny first formulated the problem and proved the theorem. Professor Vickrey greatly shortened and generalized the proof and brought it to its present form. A third proof by Matthew P. Gaffney, Jr., might equally well have been presented.

with the private discount function R: $\int_0^m PA\,dy = \int_0^m RN\,dy$.
The private discount function R will be related to P and t by the equation

$$-\frac{1}{R}\frac{dR}{dy} = r = h(1-t) = -(1-t)\frac{1}{P}\frac{dP}{dy} \qquad (3)$$

where P, R, t, and h are all functions of y, h being the public rate of discount and r being the private rate of discount. $P(0) = R(0) = 1$.

We have $\int_0^m R(y)\,N(y)\,dy$

$$= \int_0^m R(y)\,[A(y) - t(y)\,h(y)\,C(y)]\,dy \text{ [using (2a)]} \qquad (4)$$

$$= \int_0^m R(y)\,[A(y) - t(y)\,h(y)\int_y^m \frac{P(x)}{P(y)}A(x)\,dx]\,dy, \qquad (5)$$

[using (1)]

$$= \int_0^m R(y)\,A(y)\,dy - \int_{y=0}^m \int_{x=y}^m \frac{t(y)\,h(y)\,R(y)}{P(y)} P(x)\,A(x)\,dx\,dy \qquad (6)$$

which becomes, by inverting the order of integration

$$= \int_0^m R(y)\,A(y)\,dy - \int_{x=0}^m \int_{y=0}^x \frac{t(y)\,h(y)\,R(y)}{P(y)}\,dy\,P(x)\,A(x)\,dx. \qquad (7)$$

From (3), we have $ht = \frac{1}{R}\frac{dR}{dy} + h = \frac{1}{R}\frac{dR}{dy} - \frac{1}{P}\frac{dP}{dy}$ (8)

so that $\frac{t(y)\,h(y)\,R(y)}{P(y)}\,dy = \frac{1}{P}\,dR - \frac{R}{P^2}\,dP = d(\frac{R}{P})$, so (9)

that (7) becomes

$$\int_0^m R(y)\,A(y)\,dy - \int_0^m \left[\frac{R(y)}{P(y)}\right]_{y=0}^{x} P(x)\,A(x)\,dx \qquad (10)$$

$$= \int_0^m R(x)\,A(x)\,dx - \int_0^m \left[\frac{R(x)}{P(x)} - 1\right] P(x)\,A(x)\,dx$$

$$= \int_0^m [R(x)\,A(x) - R(x)\,A(x) + P(x)\,A(x)]\,dx$$

$$= \int_0^m P(x)\,A(x)\,dx = C(0).$$

Q.E.D.

APPENDIX K

FINANCIAL CHARACTERISTICS OF ENERGY FIRMS OPERATING IN ALASKA

1. The low labor intensity of large energy firms.

A. Relative to smaller energy firms.
There were 36 energy firms in Fortune 500 for 1975. Here we rank them by net worth per employee. The document trend is evident in the right column.

K-1: Top Energy Firms Listed by Net Worth Per Employee

Firm	**Net Worth**	**Net Worth /Assets**	**No. of Employees**	**Net Worth /Employee**
	Billion $	**Ratio**	**Thousands**	**Thousand $**
Socal	6.500	0.50	39	166.7
Arco	3.700	0.50	28	132.1
Exxon	17.000	0.52	137	124.1
Shell	3.900	0.56	32	121.9
S.O. lud.	5.600	0.57	47	119.1
Texaco	8.600	0.50	75	114.7
Sun	2.500	0.54	28	89.3
Mobil	6.200	0.45	71	87.3
Phillips	2.400	0.53	31	77.4
Gulf	3.500	0.52	52	67.3
Marathon	1.010	0.50	20	50.5
Continental	2.130	0.42	44	48.4
Occidental	1.200	0.34	36	33.3
Tenneco	2.400	0.36	78	30.8
Ashland	0.720	0.37	27	26.7
Sohio	1.460	0.35	73	20.0
Pittston	0.500	0.56	27	18.5
Cities S.	1.630	0.51	96	17.0
Union	1.920	0.51	128	15.0
Getty	1.900	0.59	158	12.0
Ken McGee	0.810	0.58	81	10.0
Pennz.	0.570	0.28	60	9.5
Ameraga	1.040	0.44	174	6.0
Clark	0.100	0.33	20	5.0
Texas Gulf	0.630	0.54	128	4.9
Murphy	0.340	0.29	85	4.0
Tesoro	0.223	0.38	56	4.0
Superior	0.540	0.61	181	3.0
Am. Petrofl.	0.360	0.60	121	3.0
Commonwealth	0.179	0.31	66	2.7
Charter	0.141	0.26	53	2.7
Mapco	0.163	0.38	81	2.0
United Ref.	0.044	0.37	23	1.9
Belco	0.173	0.43	108	1.6
Oil Shale	0.029	0.17	21	1.4
Crown	0.071	0.35	72	1.0
Total/Mean	80.183		2557	31.4

The top eight are all above the mean in net worth per employee. The bottom six are all below the mean

B. Relative to smaller general firms
Smaller general industrial firms are more labor-intensive than the oil firms, large and small. We have here the smallest ten firms (by net worth) from Fortune's 500.

FIRM	NET WORTH (000,000,000)	EMPLOYEES (000)	NET WORTH PER EMPLOYEE (000)
Seaboard			
All. Min.	27.5	583	47.2
Ward Foods	20.9	871	24.0
Col. Pic. Lud.	19.8	2288	7.1
Idlewild Foods	19.5	975	20.0
Mattel	16.9	12,071	1.4
Flavorland	16.9	754	22.1
Rath Packing	14.6	3,842	3.8
Spencer Foods	13.5	1,753	7.7
Sucrest	9.9	1,295	7.7
Am. Beef Packers	(10.4)	370	(28.0)
Mean	14.9	2,531	5.9

C. Relative to large general firms
Two factors are to be observed in these comparisons. Energy firms are less labor intensive than general industrial firms; and large firms are less labor intensive than small ones. To show the first point, we show data for the largest non-energy firms, 1975, ranked by Net Worth.

FIRM	NET WORTH (000,000,000)	EMPLOYEES (000)	NET WORTH PER EMPLOYEE (000)
GM	13.1	682	19.2
IBM	11.4	289	39.4
Ford	6.3	412	15.3
USS	4.9	171	28.5
DuPont	3.8	131	29.1
East Kodak	3.7	127	29.1
Union Carbide	2.7	104	25.9
Beth. Steel	2.6	112	23.2
Dow Chem.	2.5	55	45.3
Mean	5.4	223	24.2

The largest ten non-energy firms had $24,200 of net worth per employee, compared to $93,200 for the 36 energy firms, and $119,000 for the largest ten energy firms.

D. Relative to 1963
The labor-intensity of energy firms has dropped since 1963. Here are some data on firms active in Alaska. 1975 sales are 4.1 times 1963. 1975 Net Worth is 1.9 times 1963. 1975 Assets are 2.8 times 1963. But 1975 employment is only 1.1 times 1963. Of course wage rates have risen, so these comparisons overstate the trend a good deal.

Co.	SALES (000,000,000) '63	'75	'75/'63	NET WORTH (000,000,000) '63	'75	'75/'63	ASSETS (000,000,000) '63	'75	'75/'63	EMPLOYEES (000) '63	'75	'75/'63
Arco	.9	7.36	8.1	.9	3.66	4.1	1.4	7.4	5.3	18	28.1	1.6
Sohio	.5	2.5	5.0	.4	1.46	3.7	.47	4.2	8.9	10.5	20.6	2.0
Exxon	10.31	44.9	4.3	8.0	17.02	2.1	12.0	32.8	2.7	147	137.0	.9
Mobil	4.5	20.6	4.6	3.2	6.8	2.1	4.8	15.1	3.1	79	71.3	.9
Socal	2.2	16.8	7.6	2.9	6.5	2.2	3.5	12.9	3.7	44	38.8	.9
Texaco	3.4	24.5	7.2	3.5	8.7	2.5	4.5	17.3	3.8	55	75.3	1.4
Phillips	1.3	5.1	3.9	1.2	2.4	2.0	1.8	4.5	2.5	25	30.5	1.2
Cities Serv.	1.2	3.1	2.6	.9	1.6	1.8	1.6	3.2	2.0	23	17.1	.7
Union	.5	5.1	10.2	.6	1.9	3.2	.9	3.8	4.2	7	15.7	2.2
Mean	1.4	5.8	4.1	1.2	2.3	1.9	1.7	4.7	2.8	22.9	24.9	1.1

Note #1: Atl and Richfield are totaled for the 1963 figure.

2: Conversion of Prudhoe into cash.
Note in the table just above how much faster the assets of Arco and Sohio have risen than the other firms: 5.3 and 8.9 as compared with 2.8 for the whole group (which includes them).

Then note how much faster the assets of Arco and Sohio have risen than their net worth has risen: 5.3 vs. 4.1, and 8.9 vs. 3.7. This an index to how they have raised cash on the gain to their wealth caused by Prudhoe. They have taken tax-free cash by bonding the value of their leaseholds. They have done so at prime interest rates. This is the source of ability to pay rents, add valorem charges and taxes in advance of production.

Note #3: The under used credit base of larger firms
The smaller, leaner firms tend to use their credit more. We compare the ratios of net worth to total assets for the top ten, the middle ten, and the bottom ten of Fortune's 500, (be Net Worth), 1975.

	TOP TEN	NET WORTH/TOTAL ASSETS
1.	Exxon	.52
2.	GM	.60
3.	IBM	.73
4.	Texaco	.50
5.	Mobil	.45
6.	Socal	.50
7.	Gulf	.52
8.	Ford	.46
9.	S.O. lud.	.57
10.	U.S.S.	.60

	MIDDLE TEN	NET WORTH/TOTAL ASSETS
246	Sherwin Wins.	.53
247	Potlatch	.62
248	Champ. Spark.	.73
249	Crown Cork	.54
250	Hamua	.76
251	SCM	.41
252	Becton, Dick.	.64
253	Farmland	.31
254	East. Gar.	.42
255	Cherekr.-Pouds	.59

	BOTTOM TEN	NET WORTH/TOTAL ASSETS
491	Seaboard All. Min.	.27
492	Ward Foods	.14
493	Col. Pic. Indust.	.06
494	Idlewild Foods	.44
495	Mattel	.09
496	Flavorland	.29
497	Rath Pkg.	.28
498	Spencer Foods	.25
499	Su Crest	.09
500	Am. Beef	-(.19)

The bottom ten clearly are heavily in debt compared with the top ten. This is same index to the lower cost of capital to the larger firms.

Refer back to the first set of data, under heading #1, App. K, showing Net Worth/Assets for 36 energy firms. The smaller ones are using their credit harder than the larger ones. 9 of the last 10 firms are under .40. 9 of the top 10 are over .50.

Note #4: Credit ratings and long term financing
The following table shows how the effect of a low credit rating is felt more strongly for long term than short-term borrowing. Figures are from July, 1976, taken from Moody's.

Bonds Mature	Aaa	Aa	A	Baa	Ba	B
1976-80	7.2	3.7	7.6	8.3		
	6.9	6.9	7.0	8.8		
	6.5					
	3.7					
1981-85	7.9	7.9	8.5	10.0		
	8.0	8.2	8.6	10.0		
	7.9	8.3	10.0			
	5.3	8.1	9.0			
	5.5		8.3			
	8.0		8.5			
			8.9			
1986-90	11.4		6.3	8.7		14.0
			8.2	6.9		
				10.0		
1991-95	8.9		9.3	11.0	16.0	11.0
	6.8		9.1	7.4		14.4
	8.5		9.1	8.9		
	7.4		7.7			
	7.3					
1996-2000	7.6	7.6	9.8	12.0		
	7.9	8.3	8.7	9.7		
	7.9	8.9	8.8	12.0		
	7.8	8.7	7.2			
	7.7	8.5				
	7.6	7.8				
		8.7				
		7.3				
		8.7				

The specific bond issues arrayed above are identified in the following table.

Note how the Aaa bonds of Exxon, Socal, and Texaco, and the Aa bonds of Arco, yield only 7.6% to 7.9% even when they are long term.

The Baa rating of Penzoil and Tenneco pushes them up only to 8.3% and 8.8% for near instanties. But on long maturation we see a real spread between the Aaa and the Ba of Grolier (16.0% and the B of White Motor (14.4%).

While these are only fragments, they do make the point that firms with accumulated wealth have a comparative advantage in financing for the longer term.

Bonds maturing between 1976 and 1980 - Moody's Ratings		Current yield July 1976
Aaa	Ford 7¼% 1977 note	7.2
	6¾% 1979 note	6.9
	GE 6¼s 1979 deb.	6.5
	GM 3¼s 1970 deb.	3.7
Aa	Altantic Refining 3¼s 1979	3.7
	Atlantic Richfield 7.0% note 1976	6.9
A	AMAX 7½% note 1978	7.6
	Cities Service 7.0% note 1978	7.0
Baa	Pennzoil 8 3/8s deb. 1976	8.3
	Tenneco 10¼s deb. 1978	8.8
Mature between 1981 and 1985		
Aaa	DuPont 8.0% note 1981	7.9
	GM 8.05% note 1985	8.0
	Merck 7 7/8% note 1985	7.9
	St. Oil-Ca. 4 3/8s deb. 1983	5.3
	St. Oil-Ind. 4½s deb. 1983	5.5
	Warner Lambert 8.3% note 1985	8.0
Aa	Monsanto 8.0% note 1985	7.9
	Union 8 3/8s deb. 1982	8.2
	8 3/8s deb. 1985	8.3
	Xerox 8.2% note 1982	8.1
A	AMAX 8½% note 1984	8.5
	Hercules 8 3/4 note 1983	8.6
	ITT 11% note 1982	10.0
	9 1/8% note 1983	9.0
	Pepsi 8¼% note 1985	8.3
	Phelps Dodge 4¼s deb 1982	8.5

	Sybron 9 1/8% note 1985	8.9
Baa	Occidental Petro. 11.0% note 1982	10.0
	Pennzoil 10 5/83 deb 1983	10.0

Maturing between 1986 and 1990

Aaa	DuPont 8% note 1986	11.4
Aa		
A	Beth. Steel 4½s sub. deb. 1990	6.3
	Reynolds Tob, 7s sub. deb. 1989	8.2
Baa	Amax 8s deb 1986	8.7
	Internat. Harvester. 7 3/8s convert. sub. deb. 1988	6.9
	SCM 9½s deb. 1990	10.0
B	United Brands 6 3/4 1988	14.0

Maturing between 1991 and 1995

Aaa	Ford 9¼s deb 1994	8.9
	GE 5.3s deb. 1992	6.8
	Gulf 8½s deb 1995	8.5
	St. Oil-Ca 5 3/4s 1992	7.4
	-Ind 6s deb 1991	7.3
Aa		
A	Chemetron 9s deb 1994	9.3
	Intern. Harvester 8 5/8s deb 1995	9.1
	ITT 8.9s deb 1995	9.1
	Sherwin Williams 5.45s deb 1992	7.7
Baa	Chrysler 8 7/8s deb 1995	11.0
	Intern. Harvester 4.8s sub. deb. 1991	7.4
	Tenneco 7s deb. 1993	8.9
Ba	Grolier 9½s deb 1991	16.0

B	Evans $6\frac{1}{2}$s convert. sub. deb. 1994	11.0
	White Motor 6 3/4s deb 1993	14.4

Maturing between 1996 and 2000

Aaa	Exxon 6s deb. 1997	7.6
	$6\frac{1}{2}$s deb 1998	7.9
	GE $7\frac{1}{2}$s deb 1996	7.9
	St. Oil-Ca. 7s deb 1996	7.8
	-Ind 6s deb 1998	7.7
	Texaco 5 3/4s deb 1997	7.6
Aa	Atlantic Richfield 5 5/8s deb 1997	7.6
	Bet. Steel 6 7/8s deb 1999	8.5
	9s deb 2000	8.9
	Cat. Tractor 8 3/4s deb 1999	8.7
	8.6s deb 1999	8.5
	Dow Chem 7.6s deb 1998	7.8
	8.78s deb 2000	8.7
	Union Carbide 5.3s deb 1997	7.3
	Xerox 8 5/8s deb 1999	8.7
A	ITT 10s deb 2000	9.8
	St. Oil-Oh 7.6s deb 1999	8.7
	$8\frac{1}{2}$s deb 2000	8.8
	US Steel 4 5/8s deb 1996	7.2
Baa	Chrysler 8s deb 1998	12.0
	Pennzoil 8 3/8s deb 1996	9.7
	US Industries 7 3/4s deb 1997	12.0

Appendix L

PROFIT SHARE BIDDING FOR PETROLEUM LEASES

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February 1977

Competitive profit share bidding, where potential lessees bid the percentage of total profits from the lease that they will pay to the State, is an alternative to the traditional competitive bonus bidding procedure for allocating an oil and gas lease to one among several potential lessees. This approach was used by the State of California and the City of Long Beach in the 1965 sale of leasehold interests in the East Wilmington unit located in the Long Beach Harbor tidelands. A variant of this procedure is for the lessor to specify the percentage of profits that the lessee pays to the lessor and then to allocate the lease to the highest bonus bidder. To be most effective at preventing premature abandonment of the lease, profit share leases should not contain a royalty provision.

Profit share bidding has three particularly attractive features relative to bonus bidding and most other alternative bidding procedures. One is that profit share bidding permits the lessor to share in unexpectedly large future price increases that would not be built into bonus bids or into the royalty schedule included in the lease contract. Given the price trends of recent years and the future outlook for still higher petroleum prices, this advantage appears to be particularly important. However, an offset to this is that the lessor bears a higher proportion of the risks that the market price may go down in the future than with bonus bidding. The supporters of profit share bidding are arguing, in effect, that the probability of unexpectedly higher prices is greater than that of unexpectedly lower prices; hence, on balance, the State would gain from profit share bidding.

The second principal argument for profit share bidding is that it permits the State to capture more of the inherent economic rent in the lease when discoveries are unexpectedly (from the industry's point of view) large and profitable. On the other hand, the lessor bears more of the risk that the lease is unexpectedly unproductive or only marginally productive than if bonus bidding is used. If the industry shows a bias towards predicting smaller discoveries than actually occur on the average, profit share bidding would indeed provide advantages for the lessor. The author is aware of no evidence that supports the hypothesis that the industry, on the average, expects smaller discoveries than actually occur. In the author's opinion, the opposite is the more likely hypothesis--the industry probably expects a greater probability of finding commercial reserves and larger and more profitable reserves than actually occur, in which case profit share bidding would not be in the lessor's best interests.

Both of these arguments for profit share bidding presume that the State cannot or will not impose additional taxes, such as a severance tax or an *ad valorem* property tax when industry profits become so large, due to unexpected price rises or unexpectedly great productivity, as to be politically unacceptable. Since it is doubtful that any lease contract should be so written as to cover every possible outcome or eventuality, these arguments for profit share bidding do not appear, to the author, to be very strong because of the safety valve provided by the State's general taxing powers--which are implicitly accepted by each lessee when he decides to operate within the State's boundaries.

The third advantage of profit share bidding is that it can avoid the related problems of disincentives for development of the marginal portions of the reservoirs under the lease and premature abandonment of the lease that are present where the lease contract includes a royalty. This advantage obtains if all capital and operating costs (including interest on the lessee's borrowed and equity capital) are deducted from gross revenues. Where the costs of debt and equity capital are not deductible against gross revenues, the percentage of total profit going to the lessee--from which he must recover the costs of his debt and equity capital--is the determinant of whether he will make investments at the margin in pressure maintenance, development drilling, secondary recovery, etc. At the very high profit shares going to the lessor in the case of the East Wilmington unit, and given the relatively low "general contractor's" fee, the lessee's incentives to develop marginal portions of the lease are likely to be minimal. In the author's opinion, profit share bidding lease contracts should permit deductions of interest and a reasonable return on the lessee's equity capital from gross revenues when computing profits for the lease. The deduction for the cost of equity capital must be carefully set so that it will not be greater than the lessee's cost of equity capital, thus resulting in over-investment of equity capital in the lease.

Although competitive profit share bidding appears, on the surface at least, to be an attractive procedure, it is subject to several major problems with respect to its ability to maximize the landowner's wealth. The five principal problems which appear to limit the applicability of profit-sharing bidding are:

1. How can "profit" be defined so that the lessee will act in the best interests of the lessor.
2. How can "gold-plating" of physical facilities be avoided,
3. How should the oil be valued for the purpose of computing profits.
4. How can reciprocity between the lessee and its suppliers be prevented,
5. How can the portion of the inherent risk in the lease that the lessor bears be controlled by the lessor.

<u>1. The Definition of Profit</u>

As is readily apparent from any elementary course in accounting, there is no single, widely applicable, method for computing the <u>annual</u> profits from a business enterprise. This is especially the case if the objective is to compute the annual profits of one operating entity of a business firm that has other operating entities. The problems with these calculations fall into three major categories: (1) the distribution of costs (particularly the costs of capital goods subject to physical depreciation or obsolesence) over more than one annual accounting period, (2) the allocation of joint costs (particularly general administrative expenses) among the firm's several operating entities, and (3) determination of the value set on the output of one entity that becomes an input for another entity of the same firm (the "transfer price" problem). The third problem is sufficiently important in the petroleum industry that section 3 of this paper is devoted to its discussion.

The basic objective of any business firm, whether it is an oil company operating leases on government land or engaged in some line of business, is to earn as high a return as possible on its equity capital--the capital which its shareholders have invested in the business either through purchasing its stock or through decisions of the board of directors to retain earnings in the firm. Regardless of how "profits" are defined for the purposes of the Securities and Exchange Commission, the Internal Revenue Service, or for computing payments to the lessor of oil and gas lands, the business firm will "adjust" these measures of profit for the purpose of making its management decisions so that it will maximize the return on its equity capital. Thus, from the point of view of the lessor, one fundamental objective is to design the definition of profit within the lease so that the lessee, in the process of maximizing the return on its capital, will act in the best interests of the lessor.

The author has no expertise in the fine points of accounting and can little more than recommend that before profit share bidding is seriously considered by the State of Alaska, a competent accountant should make a careful study of the detailed procedures used by the State of California and the City of Long Beach with respect to the East Wilmington leases. The author also has been informed that a study of procedures for defining profit in profit share bidding leases is either being contemplated or is under way by the U.S. Department of the Interior as part of an overall evaluation of federal government oil and gas leasing policy.

2. Prevention of "Gold-Plating"

When a lessee agrees to share the profits from an oil and gas lease with the lessor, the effect is to permit the lessee to deduct all operating and capital costs (with the general exception of the "cost" of the lessee's equity capital) before computing profit. If the profit share going to the lessor is very high (it ranges between 96 and 100% for the East Wilmington unit leasehold interests), the lessee's incentives to control costs, especially those costs which can yield some benefit to the lessee which the lessor cannot capture, is substantially reduced or even eliminated. This is particularly the case where the lessee receives a "general contractor's" fee based on the cost of plant and equipment installed on the lease (this fee is 4% in the case of the East Wilmington leases).

Prevention of gold-plating is difficult and requires the creation of a skilled staff of field auditors and engineers employed by (or retained by) the State. Moreover, these state officials will likely have to be given considerable discretion with respect to what constitutes the appropriate level of capital investment and operating expenditures for the lease. This task is difficult enough for the executive managements of profit seeking business firms; however, given the nature of the political atmosphere within which state officials must make decisions, the task of eliminating or sharply curtailing gold-plating may be insurmountable. Two examples will illustrate this point.

The first example is concerned with reducting the probability of environmental damage through an oil spill or other accident. Given the growing concern for protecting the environment and the great interest of the news media in industrial accidents where environmental damage has or may occur, the government officials responsible for protecting the state's interest in the lease are under considerable pressure to prevent the occurance of oil spills that would result in political outcries by vocal environmentalists and political pressures on elected officials to "do something." What is likely, of course, is that the officials responsible for protecting the state's interests in the lease will be fired or transferred to a "deadend" position. To avoid such political risks, the responsible state officials, and even the elected officials, have strong incentives to permit gold-plating with respect to environmental protection. The East Wilmington unit provides substantial examples of such gold-plating.

Furthermore, since the political outcries resulting from an oil spill or other real or fancied environmental damage may lead to strong political pressures to shut-down the lease (as happened in the 1969 Santa Barbara Channel oil spill), the lessee also has strong incentives to gold-plate his lease with respect to environmental protection devices and to operating procedures which are exceptionally costly but reduce the probability of oil spills to acceptable levels. These incentives can operate even when the profit share going to the state is considerably less than that of the East Wilmington leases. These incentives are also present when other procedures, including bonus and royalty bidding, are used to determine the lessee; however, the ability of the lessee to deduct all costs in determining the payment to the lessor makes profit-share bidding particularly vulnerable to this kind of gold-plating.

The second example has to do with operating costs. In remote areas of Alaska subject to climatic extremes, the operators of oil production and transportation facilities provide living quarters and some level of the amenities of life to their employees. Where a very large percentage of the profits from the lease go to the lessor, the lessee has little incentive to control these costs, especially where they contribute to labor peace and minimal labor-related disruptions in the flow of oil to be marketed by the lessee. Furthermore, since labor troubles can result in considerable political pressures on elected officials for meeting the workers' demands--especially where major labor unions are involved--the officials responsible for protecting the state's interests in the lease have definite incentives to permit gold-plating with respect to worker amenities to reduce the probability of losing their jobs because of labor unrest.

It should be noted, none-the-less, that environmental gold-plating and the provision of worker amenities are not viewed as being serious problems by some interest groups--most notably environmentalists and labor union leaders. However, the issue is not whether environmental protection and the provision of worker amenities are good or bad. The basic issue here is whether a profit sharing leasing procedure will, through its incentives for gold-plating, provide the politically acceptable level of environmental protection and worker protection from the point of view of all citizens of the State and their elected officials. In general, it appears to the author that the lease contract should promote maximizing the wealth of the lessor and that the State's elected officials should make explicit political decisions with respect to the levels of environmental protection and worker amenities that should be incorporated into the lease contract as constraints on the lessee's behavior.

3. Valuation of the Oil and Gas for the Purpose of Computing Profit

If none of the State's profit sharing lessees were integrated oil companies or if all of the oil marketed by the lessee were sold on the free market to non-affiliated refiners and carried in non-affiliated transportation facilities, the market price of the oil would provide an objective standard for determining the value of the oil to be used in computing profits. In this case, the lessee could not capture a portion of the economic rent inherent in the lease through increased refining or transportation profits--except possibly through secret rebates, reciprocity or oil exchange deals. The problem of policing one of these sources of "extra" profits--reciprocity--is discussed in the next section of this paper.

Where the lessee is an integrated firm and some of the oil is sold on the free market (and the rest processed in the lessee's refinery), the free market price of the oil provides an apparently objective basis for determining the value of all oil produced by the lessee. However, there is an inherent problem with using this approach that has been a major concern of California officials responsible for the East Wilmington unit. Oil prices (including the base price and API gravity price differentials) depend upon the value of the oil, relative to alternative crude oils that could be used by refiners and the refiners' product slates, to the marginal refiner of that oil. Each refinery has its particular mix of crude oil distillation units and downstream processing units (e.g., cracking facilities), of varying ages and technologies. Some refineries are able to process more profitably a given crude oil than others. Where a refiner has on a long-term basis an assured supply of a given crude oil, he can design his refinery (and orient his marketing efforts) so that he can most profitably process that crude oil--thus, increasing its value (sometimes substantially) relative to the value of that same crude oil at the typical refinery which could profitably use that crude oil. This is, of course, the primary economic reason for vertically integrated oil companies.

By acquiring leases on lands producing a large volume of a given crude oil, the integrated refiner may be able to capture a portion of the economic rents inherent in the lease by selling some of the oil on the free market, to establish its value for the purpose of calculating the profits from producing the lease, and then building the necessary refinery units to increase the value of the crude oil above this "market price." The integrated refiner records the added profit, assuming that there is any, as a higher rate of return on his refinery investment than the rate of return just necessary to get him to invest in the refinery facilities. The "economic rent" thus captured by the integrated refiner/producer is generally called "quasi-rent" by economists because it results from the lower price necessary to sell all of the oil, by selling the excess over the refinery's requirements to a refiner who places a lower economic value on the crude oil because of his particular technology, crude oil and product mix.

A similar situation may arise where the producer owns a portion of the transportation facilities moving the oil from the field to his refinery. By tailoring his transportation facilities to the lease, he can reduce the trans-protation costs to his refinery relative to the cost of transporting the oil to the marginal refinery. This further increases the "quasi-rents" which the integrated firm can capture from the lease.

Where competitive bonus bidding is used to select the lessee, it is likely that those potential lessees who are integrated refiners, transporters and producers of oil would include in their bid at least a portion of the increased value of any crude oil they find on the lease at their refinery since this would increase the probability of their winning the lease. This would particularly be the case if the reserves under the lease are possibly large enough to make it profitable for the potential lessee to contemplate substantial modernization of his refinery in the process of adapting it to the potential oil under the lease. It is also more likely to be the case at drainage sales where the properties of the oil and its potential volume can be reasonably well estimated from previous discoveries. The ability of the lessor to capture at least a portion of the refinery profit over all costs through the bonus bid supports continuing to permit integrated refiners to bid for leases on government lands.

It is difficult for the lessor to capture all or a portion of these "quasi-rents" through provisions in the lease contract. The lessor would need to have access to the lessee's refinery simulation models, which contain the necessary cost and technological information to determine the value of the oil to the lessee. This information is normally treated as being highly confidential by refiners, on par with the explorationist's geological and geophysical information. Provisions in the lease contract giving the State access to this refinery information may be difficult to enforce and would require considerable expertise on the part of the responsible state officials to interpret.

The above discussion was with respect to oil, and by inference natural gas liquids, because valuation problems do not arise with respect to sales of natural gas to regulated interstate pipeline companies owned by others. It is unlikely that natural gas would be used by the lessee for other than oil field uses. A possible exception might be with respect to sales of natural gas to be liquified and/or transported to markets in facilities owned by the lessee. By having the liquification plant pay less than the value of the gas or by having its transportation affiliate charge more than its total costs for shipping the LNG, the lessee could reduce the profits of the lease and capture a portion of the economic rents inherent in the lease. Preventing this kind of undervaluation of the natural gas produced on the lease would involve the State in widespread investigations of the lessee's LNG operations.

In the case of either oil or gas, the nature of the profit share bidding procedure provides greater incentives for the lessee to undervalue production from the lease than bidding systems based on bonuses, rentals and/or royalties. With a royalty, the State can always take its share of production and market it itself if it believes the price paid by the lessee is too low. With profit shares, the State loses this important protection against undervaluation of the production from its lease.

4. Reciprocity Between the Lessee and Materials Suppliers

Although the Federal Trade Commission and Justice Department have long been concerned about the market-foreclosing aspects of reciprocity arrangements where a firm's supplier must buy products from that firm, reciprocity has special implications where profit sharing arrangements are included in oil leases. If the lessee can shift most or virtually all of a higher price for plant and equipment or materials and supplies to the lessor, and can thus receive lower prices or better services on goods purchased elsewhere from the supplier, the lessee has an incentive to pay more than is necessary for those goods where reciporcity is possible. Similar incentives arise where the lessee is involved in constructing transportation facilities whose tariffs are based on traditional cost-of-service regulation. This problem is more likely to occur where the lessee is a large firm with geographically diverse operations.

Short of having an "inside" informant, this type of reciprocity arrangement is almost impossible to police by state officials. There is no practical way that the State can audit the books of a widely diversified corporation to detect such arrangements. Competitive bonus bidding, however, does not present this problem since the prospects for reciprocity arrangements--if there are any--would likely be reflected in the bonus bids since that would increase the probability of the bidder's winning the lease.

This reciprocity problem potentially arose with the East Wilmington unit when the operators wanted to restrict bidding for tubular steel goods to American steel companies, rather than to permit the greater price competition that existed with foreign (principally Japanese) firms entering bids. The arguments by the lessees and the government officials managing the leases favoring restricting the bidding to American firms related primarily to the alleged higher quality of American-made products (which is related too to the "gold-plating" issue discussed above in section 2); however, since all tubular goods used on the lease had to meet the same strict specifications regardless of source, the quality argument was not particularly persuasive. The author in his study of this situation for the California State Lands Commission concluded that reciprocity must be the major economic reason for the lessee's wishing to restrict the bidding to American firms.

5. Risk-Sharing Attributes of Profit Share Leasing

Since petroleum exploration, development and production is an inherently risky business, one of the important aspects of each alternative leasing procedure is the way in which the geological and technological risks inherent in the tract of land and the market risks inherent in the oil business generally are to be shared by the lessee and lessor. For example, with bonus bidding and no royalty the lessee bears all of the risks inherent in the lease. With profit share bidding and a very high percentage of the profits going to the lessor, the lessor bears a large portion of the risks resulting from operations after the exploration and initial development phases. The proportion of risk borne by each party to the lease is a major determinant of the present value of each party's cash flow since bearing a higher portion of the risk generally increases the applicable discount rate, thus reducing the present value of future cash flows.

Given the objective of maximizing the present value of the cash flow going to the State, the State may wish to bear more or less of the inherent risks than would be implied by a profit sharing arrangment. One of the criticisms of the use of profit share bidding in the case of the East Wilmington unit was that since the area had already been explored prior to the lease sale and the oil reserves and appropriate technologies for extracting the oil had been identified, the geological and technological risks inherent in the lease were exceptionally low. The remaining risks were primarily market-oriented in nature.

Under the circumstances, the critics of the profit share bidding procedure argued that the State should have used a leasing procedure where the lessee bears virtually all of the geological and technological risks. In either event, the lessor would have to bear the same basic market risks whether profit share or bonus bidding was used. This argument implies bonus bidding; however, given the identified reserves of the lands to be leased (in the neighborhood of one billion barrels) and their location in a crude oil short refinery center, the bonus bids would have been huge by 1965 standards and could have severely constrained the industry's capital raising abilities.

The critics of the use of profit share bidding in the East Wilmington case believe that profit share bidding is most applicable to rank-wildcat prospects where the inherent geological and technological risks are greatest. In their opinion, having the lessee bear virtually all of the risks in this case likely reduces the present value of the lessor's expected cash flow from the lease relative to the situation where the lessor bears a higher proportion of the risks.

Determining the proportion of the inherent risks that the State wishes to bear is, of course, a political decision that is best made explicitly by elected officials at the time they determine their leasing policies.

The portion of the inherent geological, technological, and market risks that the lessor wishes to bear can be controlled to some extent by specifying the profit share in the lease contract and then select the lessee using the bonus bidding procedure. The smaller the profit share going to the lessor, the greater the bonus bids and the greater the proportion of the total risks inherent in the lease borne by the lessee. It is possible that the bonus bid would shift some or all of the benefits of the higher value of the oil at the lessee's refinery and even reciprocity arrangements to the lessor since under truly competitive bidding the bidder would have incentives to include such profits in his bid. The problems of defining profits so that the lessee will act in the lessor's best interests and of "gold-plating" are still present when the bonus bid is used to allocate the profit sharing lease, although they can be reduced by reducing the profit share. To the author's knowledge, such a system of awarding leases has not been used in the United States.

6. Conclusions

Although some of the above problems with profit share bidding are more-or-less common with other leasing procedures, the author believes that a careful analysis of all the alternative leasing procedures will result in a relatively low ranking being assigned to profit share bidding on economic grounds. Whether the political attractiveness of profit share bidding or a profit sharing lease contract allocated by bonus bidding is sufficient to overcome its apparent weakness with respect to its inherent administrative problems is another matter for others to decide.