

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1506 SCOMM 55: JNT. SPEC. COMM. ON STATE TAX POLICY, 1986-1987 1306

TABLE 26
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
NORTH SLOPE BASECASE
(millions of current dollars)

	Total Oil and Gas Revenue	Total Economic Rent	Royalties & Excise Taxes	Lease Bonus & Rental Payments	Income & Reserves Taxes	After-Tax Producers' Economic Rent	After-Tax Producers' Profits	Cumulative After-Tax Rate of Return ^a
<u>CUMULATIVE, 1964-1971</u>	0.0	-1546.8	0.0	1247.6	-983.6	-1810.8	-785.9	-
1972.....	0.0	-111.0	0.0	1.5	-205.5	93.0	-311.1	-
1973.....	0.0	-144.7	0.0	1.7	-124.0	-22.4	-144.7	-
1974.....	0.0	-360.2	0.0	1.8	-158.1	-203.9	-43.5	-
1975.....	0.0	-942.1	0.0	1.7	-348.0	-595.8	-54.1	-
1976.....	0.0	-1317.8	0.0	1.4	-446.3	-872.9	-269.7	-
1977.....	693.4	-584.8	141.2	1.3	-324.0	-403.2	-211.8	-
1978.....	2008.8	1079.4	490.3	1.1	88.1	499.9	195.9	-
1979.....	4909.5	3961.8	1076.9	568.4	1197.7	1118.8	1269.7	-
1980.....	9314.2	8123.1	2751.2	15.2	2544.5	2812.2	2708.6	-
1981.....	12916.6	10539.3	5430.2	3.3	2568.6	2537.2	3345.4	0.102
1982.....	11666.5	8476.0	4059.9	116.9	2148.1	2151.1	3290.4	0.106
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1964-82 (IN 1982 DOLLARS)</u>	53773.7	20797.4	17393.2	8809.1	-543.0	-4862.0	4767.3	0.106
<u>CUMULATIVE, 1964-1982 WITH PARTIAL CAPITAL RECOVERY</u>		45423.7		3162.4		25411.1		

^a"-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL NSLOPE BASECASE

TABLE 27
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
OTHER ALASKA BASECASE
(millions of current dollars)

	Total Oil and Gas Revenue	Total Economic Rent	Royalties & Excise Taxes	Lease Bonus & Rental Payments	Income & Reserves Taxes	After-Tax Producers' Economic Rent	After-Tax Producers' Profits	Cumulative After-Tax Rate of Return ^a
<u>CUMULATIVE, 1963-1971</u>	0.0	-193.9	0.0	11.2	-101.1	-104.0	-98.7	-
1972.....	0.0	-15.2	0.0	0.7	-7.8	-8.2	-9.6	-
1973.....	0.0	-18.8	0.0	0.0	-9.2	-9.7	-8.2	-
1974.....	0.0	-70.9	0.0	0.9	-33.7	-38.1	3.7	-
1975.....	0.0	-125.9	0.0	0.9	-57.3	-69.5	-1.2	-
1976.....	0.0	-85.4	0.0	561.8	-105.0	-542.1	-111.2	-
1977.....	0.0	-92.0	0.0	402.0	-154.5	-339.5	-180.6	-
1978.....	0.0	-84.0	0.0	3.4	-159.9	72.6	-179.0	-
1979.....	0.0	-93.2	0.0	491.7	-234.1	-350.7	-219.3	-
1980.....	0.0	-180.6	0.0	113.4	-217.3	-76.6	-147.9	-
1981.....	0.0	-270.5	0.0	8.1	-202.3	-76.3	-109.1	-
1982.....	0.0	-235.9	0.0	2060.4	-417.2	-1879.1	-446.5	-
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	0.0	-3623.5	0.0	5656.3	-3352.6	-5927.2	-2934.9	-
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		-427.1		5656.3		2908.1		

^a"-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT F.I.E HISTOIL AKOTHER BASECASE

TABLE 28
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS OFFSHORE BASECASE
(millions of current dollars)

	Total Oil and Gas Revenue	Total Economic Rent	Royalties & Excise Taxes	Lease Bonus & Rental Payments	Income & Reserves Taxes	After-Tax Producers' Economic Rent	After-Tax Producers' Profits	Cumulative After-Tax Rate of Return ^a
<u>CUMULATIVE, 1963-1971</u>	382.8	-389.9	71.3	1149.6	-689.7	-921.1	-757.6	-
1972.....	55.3	26.0	11.8	3.2	2.7	8.3	-6.3	-
1973.....	57.4	-11.7	11.7	1544.1	-197.7	-1369.9	-191.7	-
1974.....	79.6	-117.7	16.7	1532.0	-428.6	-1237.9	-366.1	-
1975.....	97.0	-186.3	28.9	359.6	-511.2	-63.5	-427.6	-
1976.....	126.4	-381.8	40.1	83.6	-610.5	105.0	-452.9	-
1977.....	247.8	-323.6	61.1	405.7	-468.5	-321.9	-341.0	-
1978.....	500.4	-283.6	124.3	649.7	-371.1	-686.4	-181.8	-
1979.....	1219.8	360.5	231.2	686.4	-151.9	-405.2	-23.3	-
1980.....	1927.8	677.6	425.1	1467.7	-251.6	-963.6	47.7	-
1981.....	2737.1	1078.6	565.9	2705.5	-396.5	-1796.4	12.9	-
1982.....	3430.1	1621.9	704.8	658.6	-228.8	487.3	137.4	-
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	16864.2	-1322.8	3570.5	30797.6	-13281.4	-22409.7	-10608.6	-
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		7521.8		9456.1		7776.6		

^a "-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL TXOFFSHR BASECASE

TABLE 29
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS ONSHORE BASECASE
(millions of current dollars)

	Total Oil and Gas Revenue	Total Economic Rent	Royalties & Excise Taxes	Lease Bonus & Rental Payments	Income & Reserves Taxes	After-Tax Producers' Economic Rent	After-Tax Producers' Profits	Cumulative After-Tax Rate of Return ^a
<u>CUMULATIVE, 1962-1971</u>	81143.6	23930.2	4635.2	197.3	9576.8	9520.8	6886.7	0.141
1972.....	5895.8	2785.2	336.8	5.4	1271.1	1171.9	1015.6	0.140
1973.....	6881.8	3567.3	388.2	12.0	1658.9	1508.2	1348.1	0.139
1974.....	11137.0	7007.0	619.6	32.5	3395.5	2959.3	2918.7	0.141
1975.....	13180.2	7905.6	832.8	23.6	3806.1	3243.0	3568.8	0.141
1976.....	14676.7	8815.8	972.9	31.4	4172.8	3638.7	3774.5	0.141
1977.....	15760.5	8935.5	1094.0	37.7	4151.2	3652.6	3938.4	0.140
1978.....	15988.3	7117.5	1095.7	48.1	3538.8	3034.9	3600.6	0.138
1979.....	20378.6	11329.5	1385.2	33.4	5003.6	4907.2	4986.9	0.137
1980.....	30696.2	18284.0	4492.8	41.8	3262.1	10487.3	11619.5	0.137
1981.....	42942.8	24463.3	10433.5	169.8	3516.1	10343.9	14404.0	0.137
1982.....	39785.2	20289.4	7945.4	69.4	2903.8	9370.8	11651.6	0.137
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1962-82 (IN 1982 DOLLARS)</u>	925123.0	385675.6	73416.3	2154.4	147216.4	162888.1	156936.1	0.135
<u>CUMULATIVE, 1962-1982 WITH PARTIAL CAPITAL RECOVERY</u>		443382.9		1717.9		221032.3		

SOURCE: OUTPUT FILE HISTOIL TXONSHR BASECASE

North Slope, Alaska: Table 26 contains the analogous accounting summary of Alaska North Slope production. The figures in the table do not represent an accounting for the Prudhoe Bay field or even of producing areas on state lands. Rather, they include the total regional cash flow from all exploration and development activities on the North Slope onshore and in state offshore areas. Commercial production from Prudhoe Bay began in 1977, so Table 26 shows only costs prior to that time. The negative figures for income taxes show federal income tax deductions and credits available from Alaska exploration and development expenditures. Table 26 ignores both the temporary reserves tax and the subsequent offsetting deductions from the oil severance tax. This affects the timing of cash flows between 1976 and 1979 but has little or no effect on the cumulative values.

Positive flows of economic rent began in 1978, and rose to \$10 billion in 1981, or eleven times the figure for Cook Inlet. Much higher effective severance tax rates resulted in a 27 percent share of economic rent distributed in royalties and excise tax payments in 1979. The Windfall Profits Tax raised this figure to around 50 percent in 1981 and 1982. Bonus and rental payments have been a significant share. The cumulative 1982 discounted value of the \$900 million sale in 1969 and the \$568 million Beaufort Sea sale in 1979 reached \$8.8 billion in 1982 dollars, or 42 percent of the total economic rent.

Federal and state income taxes and the producers took an approximately equal share of the economic rent from North Slope production, \$1 billion in 1979, rising to \$2.5 billion in 1980 and 1981, then declining somewhat in 1982. The cumulative discounted value of profits did not reach 10 percent until 1981, when very large current profits overtook the cumulative investment costs, escalating at a 10 percent real annual rate per year.

As mentioned above, the economic rent accounting in Table 26 is based upon simple cash flows. Another way to compute the size and distribution of economic rents is to depreciate the investment costs over the expected quantity of production.⁴ For the Cook Inlet region, where most of the original reserves had already been produced by 1982, using this method of accounting would not make a substantial difference. For the North Slope, however, this method completely changes the picture since only about one-fourth of North Slope oil reserves had been produced by 1982.

Cumulative discounted economic rent and the producers' share, shown in the bottom line of Table 26, totaled \$45 billion and \$25 billion, respectively, in 1982. These higher figures show the cumulative flows of economic rent if only the portion of total capital expenditures reflecting the fraction of reserves produced by 1982 were charged as costs up to 1982. Note that the other cumulative figures in the table would stay the same as before except for the bonus and rental figure.

Other Alaska: Table 27 shows a cost accounting of investments in exploration outside the Cook Inlet and North Slope regions. Cook Inlet and North Slope exploration costs outside developed oil and gas fields but within the geographic region are included in the accounting summaries for those regions. The cumulative 1982 discounted value of bonus and rental payments was \$5.6 billion, principally for federal OCS leases. The negative flows of economic rent of around \$100 million per year, rising to \$200 million per year in the 1980s, measure total industry exploration costs.

The figures for producers' economic rent show a deficit even larger than the total economic rent. This is because producers also pay bonus and rental payments for the nonproducing leases. The federal tax deductions partially offset the exploration costs, however. The partial capital recovery figures in Table 27 mean that the industry has not really suffered much net loss if large quantities of oil are eventually found as a result of this exploration effort. If not, the cash flow accounting will prove to be the final word.

Offshore Texas: Table 28 summarizes the accounting of economic rent for the Texas offshore region. The pattern shows some similarities to that of the Alaska North Slope. Although some production took place throughout the twenty-year analysis period, it expended rapidly in the years since 1977. Total economic rent flows were negative until 1979, rising to \$1.6 billion in 1982. Royalties and excise taxes (excise taxes limited to state leases) consumed a high share of the rent--over 50 percent until 1982--not because of high royalty rates but rather because high costs reduced total economic rent.

The most interesting Texas offshore result, however, is the size of the bonus payments. Bonus and rental payments, mainly for federal acreage, represented a cumulative total discounted value of \$30 billion in 1982. This is nearly twice as large as the cumulative value of oil and gas production. Despite the big income tax deductions and credits from exploration and development activities, regional profits were negative or negligible until 1982, when the industry earned a healthy \$137 million.

Because of the recent lease sales for which exploration was not complete by 1982, and because of rapidly expanding production, the huge bonus payments do not yield an accurate picture of the producers' position. Looking at the partial capital recovery figures at the bottom of Table 28, the cumulative economic rent would be \$7.5 billion if capital were recovered over expected production rather than as a cash flow. The producers would receive essentially 100 percent of this expected economic rent with the income tax writeoffs approximately matching the lease payment receipts.

Onshore Texas: Texas onshore results appear in Table 29. This region presents a completely different picture from all the other regions considered here. The size of total oil and gas revenues is in the tens of billions, or four times as high in the 1980s as for the Alaska North Slope region. Economic rent and extraction costs each account for roughly 50 percent of total value--a much higher share for costs than the other regions. This difference follows from the different industry structure in Texas, where relatively low costs allow profitable production from small, low-productivity fields. Nearly 200,000 wells produced oil in 1982, around 60 percent of them less than ten barrels per day.⁵

Unlike the other regions, privately-owned lands provide over 90 percent of production. Nominal severance tax rates are low, 4.6 percent for oil and 7.5 percent for gas. Because costs are such a large share of the value, however, the effective rates as a percent of economic rent are much higher. They have averaged around 10-12 percent of economic rent, considerably higher than the share of economic rent paid in Alaska severance taxes from Cook Inlet production and approximately the same as the historical share of North Slope economic rent. The federal Windfall Profits Tax took less of a bite due to lower rates for independent producers, stripper wells, etc.

Until 1979, producers kept a share of the economic rent approximately equal to their income and reserves tax payments. Income and reserves taxes actually were slightly larger due to the reserves taxes collected by Texas local governments (see discussion in Chapter II). Due to the favorable income tax treatment of oil and gas, including the depletion allowance for independent producers, estimates of federal income tax payments were relatively low during the 1970s. The large capital expenditures accompanying the decontrol of oil prices in the early 1980s (with the investment tax credit and expensing of intangible drilling costs) kept income taxes from rising apace with income.

The low income tax payments contributed to the high apparent profitability of Texas onshore oil and gas production throughout the past two decades. The cumulative discounted cash flow of after-tax profits, inflated and accruing interest at 10 percent per year to 1982, amounted to \$157 billion, corresponding to a 13.5 percent real after-tax rate of return on total capital.

One may easily misinterpret the finding of high profitability for Texas onshore production as a finding of high oil company profits. In fact, the producers' share in the base case results for the Texas onshore region displayed in Table 29 includes the private landowners' share as well as the operators' profits. In most cases, the landowner maintains a nonoperating "passive," or royalty,

interest in production. Private royalties and other lease payments affect the balance sheet of operating companies in exactly the same way as public lease payments.

A fair comparison of the Texas onshore region to the other regions should also consider the effect of lease payments to private landowners. No systematic data sources exist for revenues received by nonoperating interests in oil and gas fields. As mentioned in Chapter II, there is a wide variation in prevailing lease terms and conditions, making it impractical to make direct estimates of the size and variation of landowner payments.

Our approach is to estimate the pattern of private landowner payments by analogy to the structure of public lease payments in the Texas onshore region. The public landownership case presents an opportunity to estimate private lease payments indirectly by estimating what public lease payments would be if all Texas onshore production occurred on public lands.

Table 30 shows the summary of economic rent in the Texas public landownership case. The cash flows for the producers in this hypothetical case would more closely have corresponded to those actually received by operating companies for the historical period in the Texas onshore region. Total oil and gas revenue and total economic rent is the same in Table 30 as in Table 29, but the distribution differs markedly. Royalties and excise taxes and lease bonus and rental payments now include lease payments received on all lands.⁶

The figures for income and reserves taxes and the after-tax rent and profit measures now represent only the operating interests. The table shows that producers received very little of the economic rent until 1975 under this scenario. Operators captured an increasing share of the rent as oil prices rose during the late 1970s and early 1980s. By 1982, the cumulative discounted producers' share under this scenario was approximately one-half the amount of the base case, suggesting that landowners essentially split the private share of economic rents (around 40 percent of total rent) equally with operating companies.

Generation and Distribution of Economic Rent--Counterfactual Scenarios

Tables 31 through 34 show the cumulative discounted cash flows to 1982 for each of the four producing regions for the basecase and for a number of counterfactual scenarios. The figures for the basecase values in Tables 31 to 34 correspond exactly to the cumulative totals in Tables 25, 26, 28, and 29. The figures for the counterfactual scenarios have the same definition and are taken from the analogous Tables located in Appendix E.

TABLE 30
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS ONSHORE WITH PRIVATE ROYALTIES
(millions of current dollars)

	Total Oil and Gas Revenue	Total Economic Rent	Royalties & Excise Taxes	Lease Bonus & Rental Payments	Income & Reserves Taxes	After-Tax Producers' Economic Rent	After-Tax Producers' Profits	Cumulative After-Tax Rate of Return ^a
<u>CUMULATIVE, 1962-1971</u>	81143.6	23930.2	13894.4	6900.3	1288.3	1847.2	-678.8	-
1972.....	5895.8	2785.2	1011.6	207.2	827.3	739.1	569.7	-
1973.....	6881.8	3567.3	1180.2	577.9	1113.1	696.1	814.0	0.101
1974.....	11137.0	7007.0	1904.9	1705.1	2412.3	984.7	1999.7	0.105
1975.....	13180.2	7905.6	2274.1	499.2	2740.2	2392.0	2518.4	0.107
1976.....	14676.7	8815.8	2554.1	607.2	2995.7	2658.7	2608.7	0.109
1977.....	15760.5	8935.5	2762.8	676.7	2918.8	2577.1	2722.9	0.110
1978.....	15988.3	7717.5	2798.5	756.6	2414.8	1747.5	2463.5	0.110
1979.....	20378.6	11329.5	3563.7	531.7	3692.3	3541.8	3554.0	0.111
1980.....	30696.2	18284.0	7547.6	669.9	2641.3	7425.3	8605.2	0.112
1981.....	42942.8	24463.3	14254.6	2567.5	2670.1	4971.0	10445.5	0.113
1982.....	39785.2	20289.4	11708.3	965.0	2058.7	5557.3	7706.2	0.113
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1962-82 (IN 1982 DOLLARS)</u>	925123.0	385675.6	175153.4	64987.3	70779.6	74754.9	75034.3	0.113
<u>CUMULATIVE, 1962-1982 WITH PARTIAL CAPITAL RECOVERY</u>		443382.9		51820.3		138576.0		

^a"-" INDICATES RETURN OF LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL TXONSHR LAND

TABLE 31
CUMULATIVE DISCOUNTED CASH FLOWS, BASECASE AND COUNTERFACTUAL SCENARIOS
COOK INLET REGION, 1963-1982
(billions of 1982 dollars)

	Total Oil and Gas Revenue	Total Economic Rent	Royalties & Excise Taxes	Lease Bonus & Rental Payments	Income & Reserves Taxes	After-Tax Producers' Economic Rent	After-Tax Producers' Profits	Cumulative After-Tax Rate of Return
BASE CASE	22.1	12.4	4.6	0.9	3.2	3.7	3.9	0.124
PRICE DEREGULATION	30.2	20.6	6.6	0.9	6.2	6.9	7.1	0.144
1971 PRICE FREEZE	19.7	10.0	3.3	0.9	2.7	3.1	3.4	0.121
1976 PRICE FREEZE	20.5	10.9	3.5	0.9	3.0	3.5	3.7	0.123
TEXAS MARKET PARAMETERS	28.0	25.3	5.6	0.9	9.0	9.8	9.6	0.249
FEDERAL OCS TAX STRUCTURE	22.1	12.4	3.6	0.9	3.6	4.3	4.5	0.128
TEXAS STATE TAX STRUCTURE	22.1	12.4	4.2	0.9	3.5	3.8	3.2	0.128
TEXAS TAX AND MARKET PARAMETERS	28.0	25.3	5.3	0.9	9.4	9.7	7.6	0.218

SOURCE: TABLES 25, E.6, E.7, E.8, E.9, E.15, E.20, E.21, E.28

TABLE 32
CUMULATIVE DISCOUNTED CASH FLOWS, BASE CASE AND COUNTERFACTUAL SCENARIOS
NORTH SLOPE, 1964-1982
(billions of 1982 dollars)

	<u>Total Oil and Gas Revenue</u>	<u>Total Economic Rent</u>	<u>Royalties & Excise Taxes</u>	<u>Lease Bonus & Rental Payments</u>	<u>Income & Reserves Taxes</u>	<u>After-Tax Producers' Economic Rent</u>	<u>After-Tax Producers' Profits</u>	<u>Cumulative After-Tax Rate of Return</u>
BASE CASE	53.8	20.8	17.4	8.8	-0.5	-4.9	4.8	0.106
1976 PRICE FREEZE	23.1	-9.9	5.5	8.8	-9.7	-14.5	-4.9	-
COOK INLET MARKET PARAMETERS	54.5	21.0	27.7	8.8	-5.5	-9.9	-1.1	-
TEXAS MARKET PARAMETERS	77.9	52.1	31.6	8.8	7.7	3.9	11.8	0.118
FEDERAL OCS TAX STRUCTURE	53.8	20.8	10.5	8.8	1.3	0.2	9.8	0.113
TEXAS STATE TAX STRUCTURE	53.8	20.8	11.7	8.8	-2.6	2.9	11.2	0.115
TEXAS TAX AND MARKET PARAMETERS	77.9	52.1	22.1	8.8	5.8	15.2	19.8	0.130

"-" INDICATES LESS THAN .5 PERCENT

SOURCE: TABLES 26, E.9, E.16, E.17, E.22, E.23, E.29

TABLE 33
CUMULATIVE DISCOUNTED CASH FLOWS, BASE CASE AND COUNTERFACTUAL SCENARIOS
TEXAS OFFSHORE, 1963-1982
(billions of 1982 dollars)

	Total Oil and Gas Revenue	Total Economic Rent	Royalties & Excise Taxes	Lease Bonus & Rental Payments	Income & Reserves Taxes	After-Tax Producers' Economic Rent	After-Tax Producers' Profits	Cumulative After-Tax Rate of Return
BASE CASE	16.9	7.5 ^b	3.6	9.5 ^b	-13.3	7.8 ^b	-10.6	-
1971 PRICE FREEZE	15.5	6.2	3.3	9.5	-13.8	7.2	-11.2	-
1976 PRICE FREEZE	16.1	6.8	3.4	9.5	-13.6	7.4	-11.0	-
COOK INLET MARKET PARAMETERS	9.5	-0.6	1.9	9.5	-15.5	3.5	-14.0	-
TEXAS ONSHORE MARKET PARAMETERS	14.9	9.5	3.4	9.5	-9.2	5.9	-9.1	-
ALASKA STATE TAX STRUCTURE	16.9	7.5	3.9	9.5	-13.4	7.6	-10.8	-
TEXAS STATE TAX STRUCTURE	16.9	7.5	4.3	9.5	-14.5	8.3	-8.3	-
TEXAS STATE AND MARKET PARAMETERS	14.9	9.5	3.9	9.5	-10.2	6.4	-7.3	-

"-" INDICATES LESS THAN 10 PERCENT

^bPARTIAL CAPITAL RECOVERY FIGURES

SOURCE: TABLES 28, E.10, E.11, E.18, E.19, E.24, E.25, E.30

TABLE 34
 CUMULATIVE DISCOUNTED CASH FLOWS, BASE CASE AND COUNTERFACTUAL SCENARIOS
 TEXAS ONSHORE, 1962-1982
 (billions of 1982 dollars)

	<u>Total Oil and Gas Revenue</u>	<u>Total Economic Rent</u>	<u>Royalties & Excise Taxes</u>	<u>Lease Bonus & Rent.1 Payments</u>	<u>Income & Reserves Taxes</u>	<u>After-Tax Producers' Economic Rent</u>	<u>After-Tax Producers' Profits</u>	<u>Cumulative After-Tax Rate of Return</u>
BASE CASE	925.1	385.7	73.4	2.2	147.2	162.9	156.9	0.135
PRICE DEREGULATION	1028.3	488.9	83.4	2.2	193.6	209.7	196.0	0.144
1971 PRICE FREEZE	786.6	247.2	48.1	2.2	101.9	95.1	98.7	0.122
1976 PRICE FREEZE	865.1	325.7	52.1	2.2	137.3	134.1	131.4	0.130
ALASKA STATE TAX STRUCTURE	925.1	385.7	66.8	2.2	149.4	167.3	189.5	0.143
FEDERAL OCS TAX STRUCTURE	925.1	385.7	50.1	2.2	155.1	178.3	200.5	0.145

SOURCE: TABLES 29, 30, E.12, E.13, E.14, E.26, E.27

Cook Inlet, Alaska: The price deregulation scenario shows cumulative discounted value of revenue and economic rent rising by \$8 billion. Governments would have collected approximately \$5 billion of this amount, and industry \$3 billion. The 1976 price freeze and even the 1971 price freeze scenario show little change from the base case, measuring by implication the severity of the effects of federal price controls actually imposed on oil production in the region. On the other hand, the figures show that Cook Inlet oil fields would have been a bonanza for producers had they been developed under the cost environment prevailing in the Texas onshore region. In this case, the producers would have earned a real after-tax rate of return of 25 percent, with cumulative earnings of \$9.6 billion.

The figures in Table 31 also provide the opportunity to test several counterfactual hypotheses about state tax structures for Alaska's Cook Inlet region. Under a regime of no state taxation at all (OCS tax structure), producers receive an additional 5 percent of the economic rent, or \$0.6 billion. Under the Texas state tax structure, higher income and reserves taxes (mainly local reserves taxes) compensate for lower severance taxes. Producers' cumulative economic rent rises by \$0.1 billion, but profits fall by \$0.7 billion due to the difference in timing of reserves tax payments compared to severance taxes.

North Slope, Alaska: North Slope oil and gas prices never really felt the burden of regulation (except for the export limitation, discussed in Chapter V), so this scenario is not applicable. Production is also infeasible under the real wellhead prices prevailing in 1971 (1971 price freeze). As can be seen from Table 32, the 1976 price freeze scenario does not yield profitable production either, due to the inclusion in the regional accounting of all exploration expenditures occurring on the North Slope.

The Texas market and cost scenario, although it yields 2.5 times as much cumulative discounted economic rent as the base case, allocates only \$7 billion, or 22 percent, of the increase in rent to producers. This derives from our assumption that with the Texas onshore price and cost parameters come that region's base prices for the federal Windfall Profits Tax. Contradicting the results obtained from the Cook Inlet region, the Texas state tax structure yields significantly less state and local revenue from North Slope production and \$6.4 billion more in after-tax profits than Alaska's tax structure (base case). This is due to the higher effective severance tax rates and the state income tax in effect during the early 1980s.

Offshore Texas: Table 33 shows the cumulative discounted cash flows for the Texas Offshore region. Because of the large exploration and development expenditures (including bonus bids) just recently bearing fruit in production, we use the partial capital recovery figures for economic rent and bonus and rental payments.

Like Alaska's North Slope, federal price controls had relatively little impact on Texas offshore production, so this scenario is not included.

The 1971 and 1976 price freeze scenarios reduce economic rents by \$1.3 and \$0.7 billion, respectively, with about one-half of the reduction coming from the producers' share. Production is not feasible with the market prices and costs prevailing in Alaska's Cook Inlet region, due entirely to the much lower prices prevailing in the latter region. With the substitution of Texas onshore price and cost parameters, economic rent becomes larger despite smaller total revenue (due to stiffer price controls onshore). It is difficult with this and with the regional tax scenarios to determine the distribution of economic rent, due to the dominating role of the federal tax deductions in determining the private and public shares.

Onshore Texas: Table 34 summarizes the counterfactual scenario results for the Texas onshore region. We do not include the public landownership case since the tax structure assumed in this case is not consistent with the structure in the other cases, due to the special treatment of lease payments. Production from the average field in the Texas onshore region is not feasible under the Alaska market and cost environment, so that scenario is not included either. Cumulative discounted value of economic rent of \$385.7 billion is approximately 40 percent of total base case revenue. Governments received 19 percent of the total rent in excise taxes and royalty payments, under 1 percent in bonus and rental payments, and another 38 percent from income and reserves taxes. Producers, including private landowners, received the other 42 percent.

Price deregulation would have raised revenue and economic rent by around \$100 million, with 10 percent of the incremental rent taken by royalties and excise taxes and the rest split evenly between income and reserves taxes and private interests. The 1971 and 1976 price freeze scenarios reduce economic rent by 36 percent and 16 percent, respectively. Royalty and excise taxes decline by 34 percent and 29 percent, respectively (absence of Windfall Profits Tax in these scenarios reduces excise taxes), but the private share declines by 42 percent and 18 percent.

If the tax regime prevailing on the federal OCS were in effect in Texas, private interests would have received approximately 10 percent more of the total economic rent and 28 percent more in discounted after-tax profits. Under the Alaska state tax structure, cumulative after-tax producers' economic rent is essentially unchanged from the base case. After-tax profits are \$30 billion higher, however, due to the effect of the timing of reserves tax payments.⁷

Summary and Discussion

We may combine the historical accounting of petroleum revenues and their distribution that was the subject of Chapter XI with the results of our analysis of economic rent discussed in this chapter. This permits us to place quantitative estimates into Figure 1, the flowchart for economic rent, for the recent historical period. It is possible to discuss the generation and distribution of economic rent in each year for each of the regions. We select, however, four representative examples from the past decade to serve as the basis for discussion.

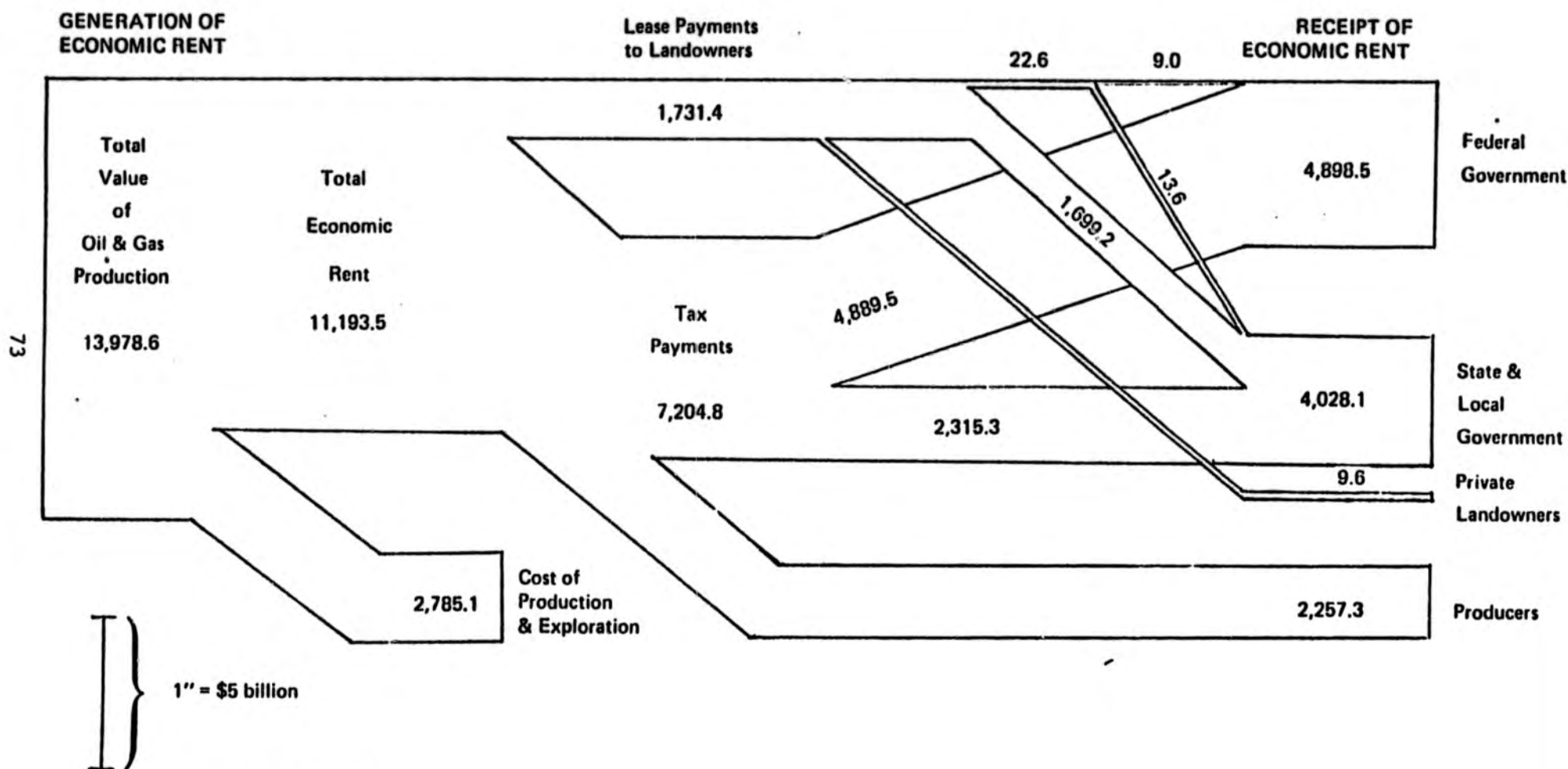
The Figure 2 flowchart illustrates the size and distribution of economic rent from petroleum development in all three regions of Alaska combined in 1981. Figure 3 summarizes the size and distribution of economic rent in the same year for the two Texas regions combined. This was the peak year for oil prices, which were by that time fully decontrolled. The federal government, with the Windfall Profits and corporate income taxes, was in a favorable position to capture a large fraction of the economic rent from price decontrol, however, as indicated by the large federal tax share in Figures 2 and 3.

Figure 2 shows that Alaska received around \$1.7 billion in lease payments (mainly royalties) and around \$2.3 billion in taxes on petroleum economic rent. Federal and private lease payments were insignificant in 1981 but have since reached billions of dollars due to bonus payments for OCS lease sales. The \$13.6 million flow in Figure 2 leading from federal lease payments to state and local government represents sharing of federal lease revenues with the state of Alaska. Producers were able to keep about \$2.3 billion in 1981, or around 20 percent of the total Alaska economic rent of \$11.2 billion.

Producers retained nearly 50 percent more economic rent in Texas as in Alaska, not including lease payments to private landowners, as shown in Figure 3. Because petroleum economic rents were so much higher in Texas, however, this amount was only 13 percent of the total economic rent and 7 percent of the value of production. While the federal government received \$3 billion in lease payments, nearly all of this came from OCS activities so that only a negligible amount was shared with state and local governments.

Private landowners received a large share in 1981, \$5.4 billion, net of around \$850 million in direct taxes. In all, taxes on oil and gas economic rent took 51 percent of the total, with over \$9 billion going to the federal government and nearly \$4 billion flowing to state and local governments. Figure 3 also shows that federal price controls (on natural gas) allocated around \$600 million of potential economic rent to consumers in the form of lower prices.

Figure 2. Generation and Distribution of Economic Rent from Oil and Gas Production
Alaska, All Regions, 1981
(millions of dollars)

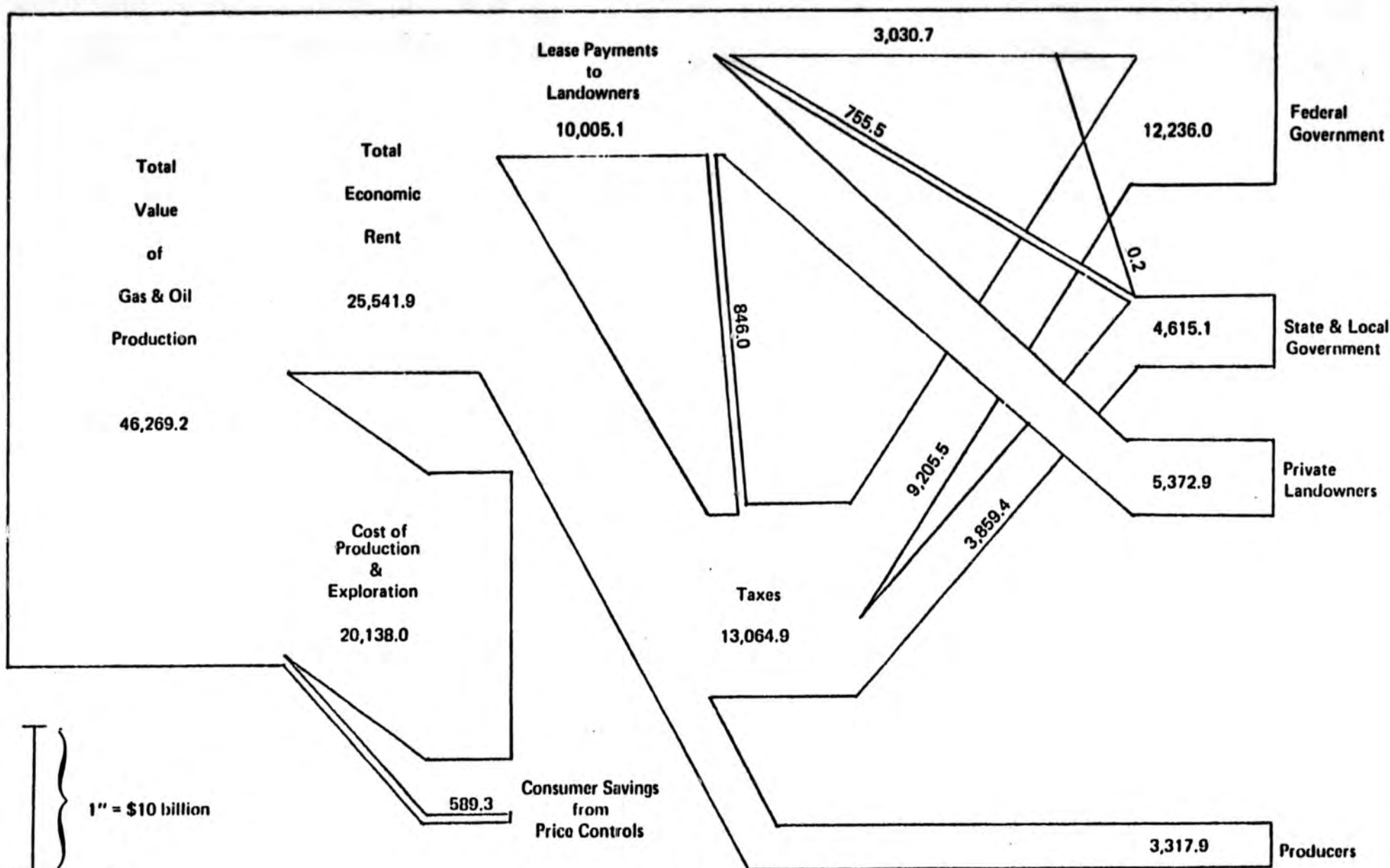


Source: Tables 11, 12, E.1, E.2, E.3.

Figure 3. Generation and Distribution of Economic Rent from Oil and Gas Production
Texas Onshore and Offshore, 1981
(millions of dollars)

**GENERATION OF
ECONOMIC RENT**

**RECEIPT OF
ECONOMIC RENT**



1" = \$10 billion

Figures 4 and 5 illustrate the size and distribution of petroleum economic rent in 1976 for the Cook Inlet of Alaska and the Texas onshore region. Including the Alaska North Slope, other Alaska and the Texas offshore regions in the flowcharts would distort the picture due to the very large exploration and development expenditures occurring in these regions in 1976 along with little or no production.

In the Cook Inlet region, Figure 4 shows the severe impact of federal oil price controls in 1976, which reduced the value of oil and gas production (if valued at decontrolled oil price levels) by over 50 percent. Of the \$288 million remaining in economic rent, producers received 39 percent, state and local governments in Alaska received 27 percent, and the federal government received 34 percent. This is a much higher producers' share than received in 1981 in either Alaska or Texas.

In Texas, the impact of federal price controls was less severe in 1976 than in Alaska, but nevertheless substantial. Figure 5 shows that price regulation essentially transferred \$5.8 billion, or 28 percent, of the value measured at decontrolled market prices of oil and gas. Federal income taxes collected 39 percent of the \$8.8 billion remaining of economic rent, while the state and local governments in Texas received 20 percent in taxes and lease revenues. The private share of economic rent in Texas in 1976 was 41 percent, including a 13 percent share for lease payments to private landowners.

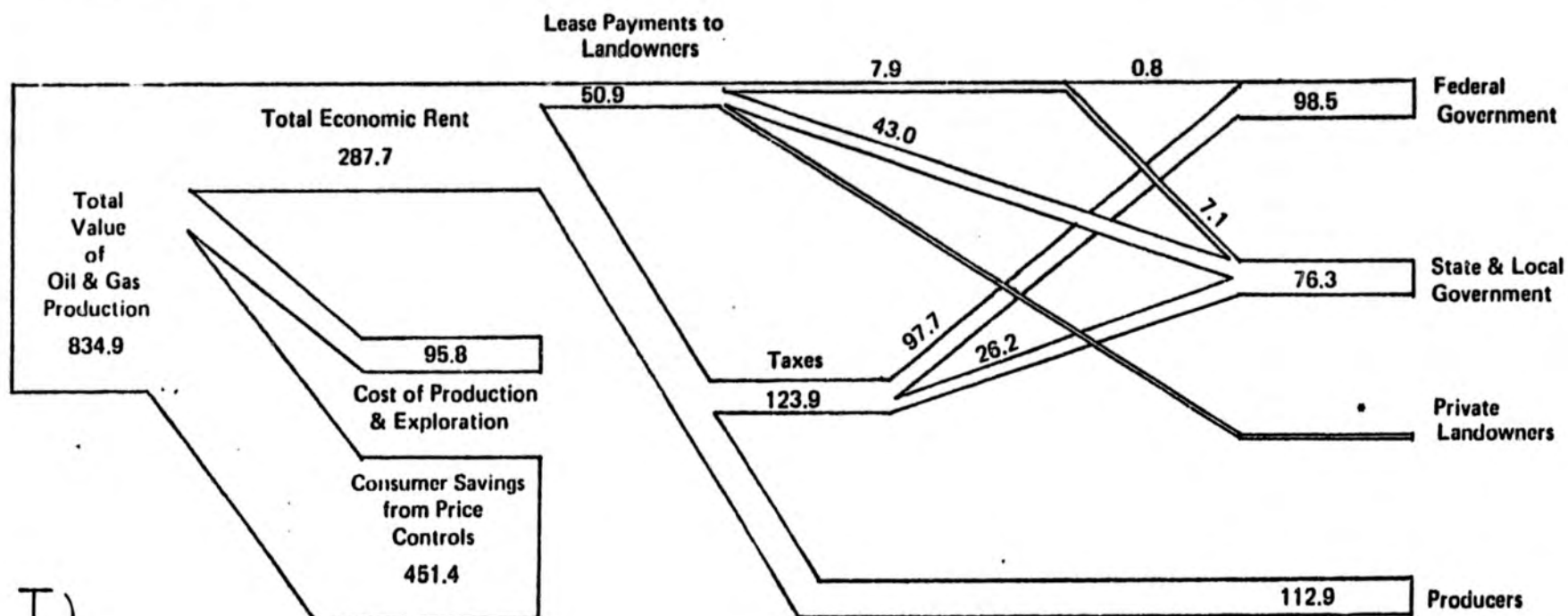
We may draw several conclusions from the comparative analysis of the size and distribution of petroleum economic rent in Alaska and Texas. The counterfactual scenarios provide the opportunity to examine quantitatively how important various factors are in explaining the pattern observed over time and across geographic regions. We were able to measure significant changes in cumulative revenue streams resulting from the application of one or another state tax system. Changes in market prices occurring over the past decade and federal programs to redistribute potential and actual economic rent created by these market fluctuations have been much more significant, however.

We have estimated in Tables 31 and 32 that the effect of federal wellhead price control programs has been to reduce cumulative discounted economic rent by \$8 billion in the Cook Inlet region and by over \$100 billion in Texas. We have also noted that Cook Inlet oil fields would have been extraordinarily profitable for industry if developed under the market and cost environment prevailing in Texas instead of the relatively high-cost Alaska environment. On the other hand, Texas industry onshore would be practically nonexistent if Alaska economic conditions prevailed there.

Figure 4. Generation and Distribution of Economic Rent from Oil and Gas Production
Alaska Cook Inlet, 1976
(millions of dollars)

GENERATION OF ECONOMIC RENT

RECEIPT OF ECONOMIC RENT

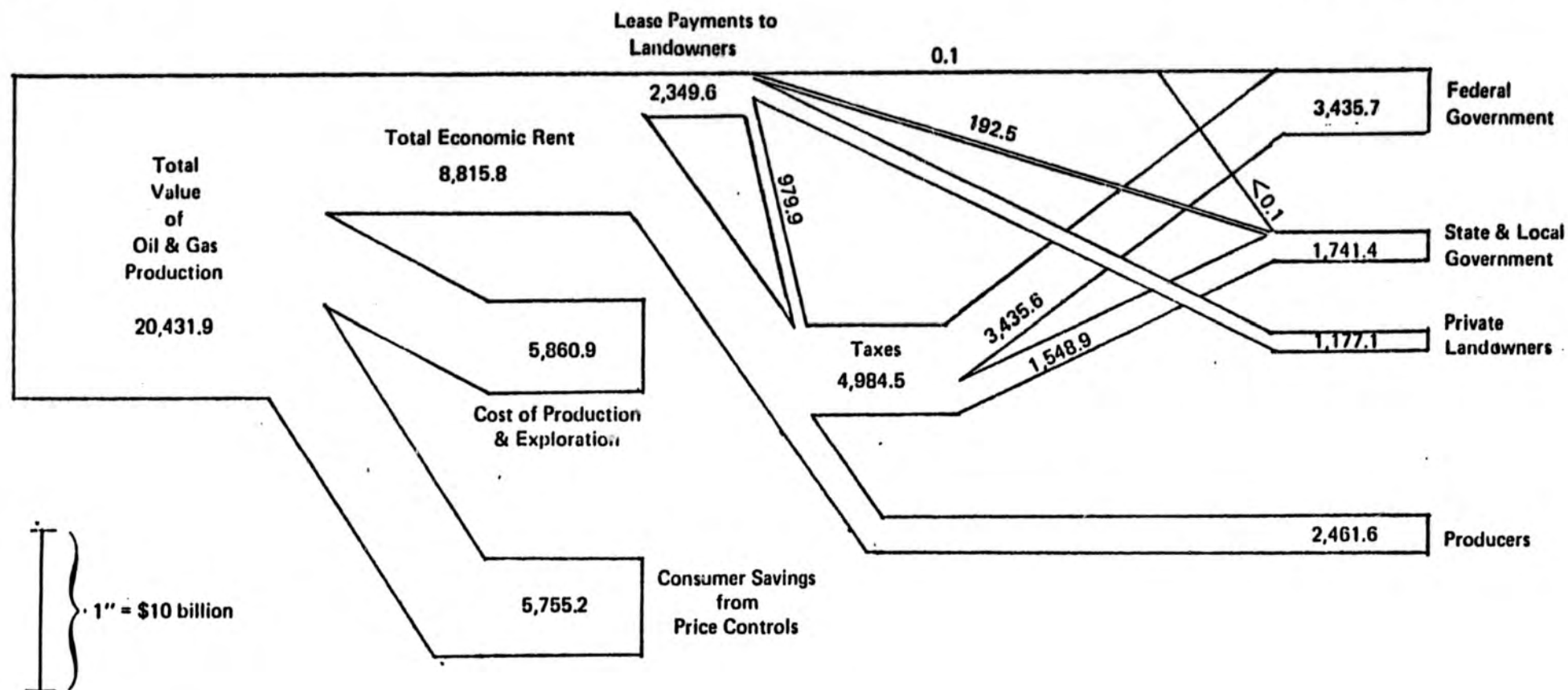


Source: Tables 11, E.1, E.6.

Figure 5. Generation and Distribution of Economic Rent from Oil and Gas Production
Texas Onshore, 1976
(millions of dollars)

**GENERATION OF
ECONOMIC RENT**

**RECEIPT OF
ECONOMIC RENT**



Source: Tables 23, 24, E.4, E.12.

We have noted that there is little systematic difference in the effective impact of state and local petroleum tax systems in Alaska and Texas on distribution of economic rent. The Alaska tax system yielded more revenue from Alaska North Slope production than would the Texas system, but the Texas system yielded more revenue in Texas than would the Alaska system. For the Cook Inlet region, the tax systems of both states yield similar revenues. These findings result from the effect of the economic limit factor in reducing average Alaska severance tax rates for all but the most productive oil and gas fields.

In any event, neither state tax system had a large effect on discounted cash flows of the industry in the historical period when compared to the effects of federal policy toward price fluctuations. This is apparent from the figures in Tables 31 to 34 for the OCS tax structure case. No state oil and gas taxes apply in this scenario, and the change in net discounted cash flows to industry raises the implied rate of return by 0.4 percent and 0.7 percent over the base case level in the two Alaska regions and by 1 percent over the base case level in Texas.

ENDNOTES

¹Local petroleum accountants have suggested that this would be likely to underestimate private royalties, particularly in recent years.

²Data from the American Petroleum Institute, Basic Petroleum Data Book, 1983.

³In the historical accounting summaries described in this chapter, "discounting" cash flows received in prior years to 1982 refers to accumulating interest at a real annual rate of 10 percent per year (the discount rate chosen to represent the opportunity cost of capital).

⁴We assume a fixed decline rate to recover all real capital costs over expected oil production. See Appendix D for the exact method. Note that the annual depreciation of capital costs with this method will not correspond to the definition of income for income tax purposes, which allows only depreciation of nominal capital costs over an arbitrary schedule. The income tax definition is the basis for the "profits" variable in the accounting tables.

⁵National Stripper Well Survey, 1983. See Appendix D.

⁶The difference between Tables 30 and 29 for these two columns is the estimate of private lease payments. Excise tax payments include Windfall Profits Tax on the private royalty share.

⁷In order to apply the Alaska severance tax to onshore Texas oil and gas production, it is necessary to revise the economic limit factor parameter representing the production rate at the economic limit (see Appendix D). In Alaska, the limit is set presumptively by statute at 300 barrels per day for oil and 3,000 mcf per day for gas. Very few, if any, wells yield these rates of production onshore in Texas. For the analysis in this study, we set the economic limit for tax purposes at an annual average production of 3.3 barrels per day for oil and 100 mcf per day for gas.

Whole
chapter

CHAPTER IV

EFFECTS OF LEASE AND TAX POLICY ON ALASKA PETROLEUM EXPLORATION AND DEVELOPMENT

Introduction

Chapter III contained a quantitative analysis of the size of economic rent and its distribution among government and private claimants in regions of Alaska and Texas. We also examined the hypothetical effects of a number of counterfactual scenarios on the historical distribution, ignoring the potential impacts on production of the assumptions associated with each of the scenarios. This chapter focuses instead on the methods used by landowners and governments to collect their shares of the economic rent. In particular, we analyze how various commonly used rent-collection mechanisms affect incentives for private exploration and development and, in the long run, oil and gas production.

The economic effects of alternative methods of taxation of natural resources have been considered in innumerable studies, including several textbooks.¹ The effects of alternative leasing systems available to public (and private) landowners have similarly been the subject of considerable theoretical and empirical study.² The basic conclusion which one may draw from the body of this research is that no practical mechanism exists for redistributing economic rent from industry operators to landowners and governments which is not associated with some adverse economic incentives or costs.

The consensus among economists is that a pure lump-sum transfer, such as a lease bonus payment, is the only mechanism for transferring economic rent without adverse incentives on production or exploration. Conventional bonus bid lease sales are not without problems of their own, however. In the first place, the traditional royalty share of even as little as one-eighth of production introduces undesirable economic effects, as we shall show below. Secondly, bonus bid lease sales depend heavily on strong competition in order for the landowner to receive a high proportion of the expected value of the lease. This requirement of competitiveness is surely violated for both state and federal lease sales in Alaska, in which very few tracts offered for lease attract more than two or three bids.³

Even if public and private landowners were able to collect a large portion of the economic rent through a competitive bonus-bid lease sale without a royalty or net profit share, the lease sale process itself introduces waste. Since the transfer of rent from producer to landlord relies on a competitive sale, the redundant

gathering of geological and geophysical data, tract evaluation, and bid preparation by prospective bidders (all under the tightest cloak of secrecy) compromise an unavoidable cost of the system. More difficult to defend as a socially desirable expense is the practice of drilling "COST" (Continental Off-structure Stratigraphic Test) wells prior to federal OCS lease sales. These wells, drilled where oil or gas is considered unlikely to be present, gather geological information to help firms prepare bids for upcoming lease sales. If they could be drilled "on-structure" at the most promising spot within the lease area, the same investment by industry might produce the first exploratory wildcat well in the area.

Another element of waste introduced by the leasing process derives from the fact that a lease for oil and gas development differs from a sale by the landowner of property rights to subsurface minerals. Leases typically have a term of five to ten years, with automatic extensions as long as commercial production continues. However, the potential loss of an oil and gas lease due to lack of diligence in exploration or production may cause producers to incur some exploration and production expenses which would be more valuable if they were made at some other time. The purpose of limiting the term of the lease is to limit the degree of speculation on the future value of exploration or development property. Yet that speculation in oil and gas property, just as in other kinds of property, is an essential part of the market system for allocating resources efficiently over time.

Despite waste and inefficiency inherent in the leasing process, these costs are probably small relative to the advantages of competitive bidding over other means of redistributing economic rent from producer to landowner. It is significant to note, however, that competitive bidding for oil and gas leases is almost unique to the United States among nations of the world. This is true in part because private ownership of subsurface mineral rights is not widely recognized elsewhere. Perhaps more importantly, governments outside the United States typically pass over competitive bidding as a mechanism of awarding petroleum leases, negotiating instead directly with individual producers.⁴ Governments in these countries rely heavily on the tax system as a means of collecting economic rent from the producers.

The situation of foreign governments is analogous to the situation in this country in which governments attempt to collect petroleum economic rent from lands which they do not own. As with leasing methods, no system of taxation exists to redistribute economic rent which does not have some adverse effects. The following section reviews the basic economic principles of petroleum exploration and development. It provides a framework for analyzing the effects of alternative lease and tax mechanisms by defining the limits of profitable operations (i.e., economic feasibility) with a simple petroleum economic model.

Following the section on the principles of petroleum economics, we summarize the available information on undiscovered recoverable petroleum resources in various regions of Alaska. We address the potential impacts of prevailing and potential tax and lease terms on future Alaska oil production in approximate terms. The analysis compares the type of effects noted for Alaska to those likely to be present in other petroleum-producing regions, such as Texas, which are characterized by different market and cost parameters.

Taxes, Lease Payments, and the Economic Margin

This analysis shows how various methods which governments use to collect economic rent may reduce total economic rent, total petroleum production, and ultimately, total petroleum revenue. We first define how one may observe the effects of taxes and lease payments on the economic feasibility of private investment in oil and gas exploration and development. Next, we outline some basic principles of petroleum economics needed for the discussion, using a simple mathematical model. We illustrate the arguments with several numerical examples representative of the exploration and development cost environments prevailing in various regions of Alaska.

Defining the Economic Margin for Petroleum Development

Three terms define the limits to economic feasibility of petroleum extractive activities. These terms refer explicitly to decisions producers routinely make regarding investments in exploration for new fields, investments in development of known fields, and abandonment of producing oil and gas fields. The terms are as follows.

1. Margin of production: the point in time at which the value of oil or gas produced from a field declines below the cost of operating the field (time of abandonment).
2. Margin of development: the size of a newly-discovered field which is just large enough so that the expected present discounted value of after-tax producer profits from developing it for commercial production equals zero (minimum economic field size).
3. Margin of exploration: the probability that oil is present in commercial quantities in a lease area (often called the "marginal probability") which is just high enough to induce industry interest in exploration (that is, producers would expect just to break even from investing in exploration of the area).

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It is important to note the interdependent nature of the three economic margins defined here. The expected time of abandonment affects the anticipated feasibility of oil and gas recovery from developing a new field. In this way, a tax or lease measure which affects the margin of production is likely to affect the margin of development as well. The minimum economic field size also influences the margin of exploration by affecting the range of possible discoveries which might be economically feasible to develop.

The analysis below takes these interdependencies directly into account. We start by analyzing the effects of tax and lease payment regimes on the margin of production. We then move to the effects of taxes and lease payments on the margin of development, considering the effects on the margin of production. Finally, we analyze the effects on the margin of exploration, considering the influence of the tax and lease terms on the margin of production and on the margin of development.

Basic Tax and Lease Payment Forms

Conventional taxes and lease payments can be divided into four broad categories according to the manner in which they are assessed. The first and simplest category is the lump sum payment. This is a one-time payment not affected in any way by future actions of the producer. Lease bonus payments, as a lump sum transfer, become a sunk cost after the lease acquisition, having no effect on later exploration and development decisions of producers. The prospect of paying bonus bids may influence exploration decisions prior to leasing, however. We assume that these effects of bonus payments on the margin of exploration are relatively small and can be ignored for practical policy purposes.⁵

Oil and gas leases traditionally include a royalty, reserving to the landowner at least a one-eighth share of total production. Total royalty payments, then, are simply proportional to the total production of oil and gas.⁶ The economic effects of royalty payments are identical, therefore, to the effects of excise taxes since both are levied as a constant share of total production. Severance taxes, the oil conservation tax, and the federal Windfall Profits Tax are all excise taxes on petroleum production in Alaska.

A third category for analyzing lease payments and taxes on oil and gas development includes net income shares. Federal and state income taxes and net profit shares in leases are the principal examples in this category. The various income taxes and profit shares used by different governments use differing definitions of net income as the base for the shares. The federal tax allows producers to deduct intangible drilling and most exploration costs from net income, while state authorities require firms to capitalize and depreciate these costs, for example.

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Alaska state net profit share leases allow full capital recovery before profit-sharing begins. In this way, the base on which the net profit share is assessed comes closer to the actual realized economic rent than that of any other tax or lease payment. Significantly, however, a firm may deduct losses on one lease or area from profits in another for computing the income tax, but not for computing the net profit share. This means that the net profit share lease requires producers to share with the government some of the profits from successful ventures but does not allow them to share any of the losses for unsuccessful ones.⁷

The final important mechanism used by governments to collect revenue from oil and gas development is the property tax. Property tax payments are usually assessed as a percentage of the depreciated replacement cost of fixed capital assets. The principal effect property taxes have on the producers is to raise the cost of exploration and development investments. Once these capital expenditures have been incurred, the property tax becomes essentially a fixed cost, like a bonus or rental payment.⁸ In other words, property taxes affect the margins of exploration and development but not the margin of production.

Property taxes, unlike lease payments and petroleum severance taxes, are an added cost to real capital expenditures for all industries, not just the oil and gas industry. Following the accounting framework of Chapter IV, then, we do not include these as mechanisms to redistribute petroleum economic rent. The reader may infer the effects of higher property taxes on the economic margins from the analysis below of the effects of higher development costs on the margin of development (and, by implication, on the margin of exploration).

The federal and state governments also collect some income taxes (but not net profit share lease payments) from investments earning a positive return to equity but a rate lower or equal to the long-run competitive return. Recall that there are no economic rents in this situation. For this reason, we depart from the practice used in other analyses in the study and exclude income taxes from the analysis of the economic effects of methods used to collect economic rent. In this section, we include income taxes as part of the cost of capital for the purpose of examining the economic margins, using a pre-tax competitive rate of return to measure the cost of capital.

A Simple Model of Oil Exploration and Production

We now examine the effects of the basic lease payments and taxes on the economic margins with the aid of a simple model of petroleum production and exploration. For ease of exposition, the analysis considers production of a single commodity: crude oil. The inferences developed from the single-commodity analysis, however, are readily generalized to a situation of multiple petroleum outputs.

For this analysis, we characterize industry actions as rational profit-seeking investments, given the limited information available and the uncertainty prevalent about important future parameters. At first, we assume that firms are able to anticipate future events, removing the element of risk from the analysis. We use the risk-free model to examine the effects of taxes and lease payments on the profitability of continued production and of field development investments, where the level of risk is relatively low. We then add risk to the model, analyzing the effects of taxes and lease payments on the feasibility of investments in petroleum exploration.

We structure the model around a common petroleum industry rule of thumb by projecting oil production as a constant fraction of technically recoverable reserves. Specifically, crude oil production in the initial year follows the assumption

$$q_0 = \gamma RQ \quad (1)$$

where q_0 , initial year crude oil production (at time $t = 0$), is a fraction γ of recoverable reserves, the production of initial oil in place, Q , and a maximum technical recovery rate, R . Production over time, t , declines with the simple relationship as reserves are depleted:

$$q_t = q_0 e^{-\gamma t} \quad (2)$$

The model represents total operating cost, c , simply as proportional (in inflation-adjusted dollars) to the initial production rate, q_0 :

$$c_t = c_1 q_0 \quad (3)$$

While operating cost stays constant over time in real dollars, the price of oil, p_t , may rise or fall at a trend rate, α , relative to inflation:

$$p_t = p_0 e^{\alpha t} \quad (4)$$

Net operating revenue in each year (in real dollars), N_t , is

$$N_t = p_t q_t (1-r) - c_t \quad (5)$$

where r , the excise share, is the fraction representing the total share of production taken by landowners and governments in the form of lease royalties and all excise taxes combined.

The model field stops producing when operating revenue declines with production until it is less than operating cost, or when N_t becomes less than zero (we assume field abandonment costs are

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$$N_t = p_t q_t (1-r) - c_t \quad (5)$$

where r , the excise share, is the fraction representing the total share of production taken by landowners and governments in the form of lease royalties and all excise taxes combined.

The model field stops producing when operating revenue declines with production until it is less than operating cost, or when N_t becomes less than zero (we assume field abandonment costs are

negligible for simplicity). Combining equations (1) through (4), we solve for the final year of production, t^* , as a function of only the initial oil price and operating cost, the excise share, and the parameters α and γ :

$$t^* = \log[c_1/(p_0(1-r))]/(\alpha-\gamma) \quad (6)$$

Given the field abandonment time, t^* , cumulative production and revenues are derived from the integrals over time from $t = 0$ to t^* as follows. Cumulative production over the life of the field is

$$Q = (q_0 - q_{t^*})/\gamma \quad (7)$$

The present discounted value of total revenue is, similarly,

$$V = [-1/(\alpha-\gamma-\delta)]p_0q_0(1-r)[1 - e^{(\alpha-\gamma-\delta)t^*}] \quad (8)$$

where δ is a discount rate representing the real pre-tax rate of return available from alternative investments (opportunity cost of capital).

Effect on the Margin of Production (Time of Abandonment)

Equation (6) shows the relationship between the excise share--the combined share of production taken by royalties and all excise taxes--and the field abandonment time, t^* . As the share grows, the logarithmic expression declines, indicating earlier abandonment. As a rough indication of the magnitude of the effect of the excise share on abandonment, consider production from a field declining at 10 percent per year. Net revenues would decline by slightly more than 10 percent per year (due to subtracting the fixed operating cost from the declining revenues). At most, then, a 10 percent reduction in the excise share would yield only one more year of production.

After as little as ten years of production, an additional year's production from a field declining at a rate of 10 percent per year would add around 5 percent to cumulative production. After 15 years, an additional year would add only another 2.6 percent. This analysis suggests that those who argue that severance taxes (as well as other excise taxes and royalties) cause early field abandonment and loss of production may have overstated their case. The effect is clearly present in this simple model, but the quantitative impact appears to be minor.⁹

Net profit shares, unlike excise shares, do not affect the margin of production in any way. Since there is no income to share at the time of field abandonment, neither the landowner nor the producer would wish to change the margin of production.

Effect on the Margin of Development (Minimum Economic Field Size)

An important factor determining the margin of development for oil fields is the relationship of field development costs to the size of the field or to field production capacity. Equation (10) contains the simple but general assumption that field development costs in a frontier region such as Alaska contain a minimum fixed infrastructure investment, k_0 , and a variable component, k_1 , depending on the production capacity:

$$K = k_0 + k_1 q^m \quad (10)$$

where K stands for development capital costs measured at time $t = 0$, and m is a scale factor allowing for economies of scale in development costs.¹⁰ Including operating costs over the life of the field, the present discounted value of total costs (measured at $t = 0$) is

$$C = K + (c_1 q_0 / \delta) [1 - e^{-\delta t^*}] \quad (11)$$

The total net profit derived from developing and operating the field, then, is the difference between the present value of net operating revenues, V (discounted to time $t = 0$) from equation (8), and the present value of total costs, C , from equation (11). At the margin of development, the present value of net profits is exactly zero, indicating the limits to economic feasibility. One can solve for the margin in the form of the minimum economic field size (RQ) as a function of the initial oil price (p_0), given the assumptions about capital and operating costs (c_1 , k_0 and k_1), the excise share (r), and the parameters α , δ and γ .

The parameter γ , representing the ratio of production to reserves, is actually a variable determined simultaneously with the minimum economic field size. The complete problem of finding the minimum economic field size with this simple model is to solve for the smallest minimum economic field size possible from varying γ at a given price of oil. This problem is equivalent to finding the initial production capacity of a field which maximizes profits, given the market price and other parameters, but for which the maximum profit is exactly zero.¹¹

Because of the tedious algebraic solution to equations (8) and (11), and because of the complexity of the calculus of variations needed to solve simultaneously for the optimum production decline rate and the minimum economic field size, we do not reproduce it here. Instead, we solve equations (1) through (11) for the minimum economic field sizes using a number of numerical examples. Chapter V contains some specific analyses of the limits of feasible production from known as-yet-undeveloped Alaska fields. The purpose of the examples given here is to illustrate the type of effects on the margin of development generally prevailing in frontier Alaska regions likely from tax and lease payments.

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We assume three scenarios representative of the range of field development costs experienced in regions of Alaska. These are derived directly from the material summarized in Appendix B. The low cost scenario represents onshore development in a region where basic infrastructure exists to support the petroleum industry operations, such as on the Kenai Peninsula. The mid-range cost scenario represents development in an onshore Arctic region, such as on the North Slope where some infrastructure exists but development costs are high. The extreme case corresponds to the limits of exploration offshore in Arctic waters where no infrastructure exists and where industry faces the highest development costs, such as in the Navarin Basin OCS lease area.¹²

One obtains the optimum value of γ by finding the smallest minimum economic field size (RQ) as a function of the price of oil, p_0 , which solves the equation system (1) through (11), given the excise share, r . The optimum value of γ is unstable, however, moving in a range from around 5 percent to around 20 percent in response to reasonable changes in the minimum price.¹³ Fortunately, large changes in the decline rate have little quantitative effect on the minimum field sizes. Since the optimal values for γ ranged around 10 percent, we decided to assume this rate parametrically for illustrating results of the model.

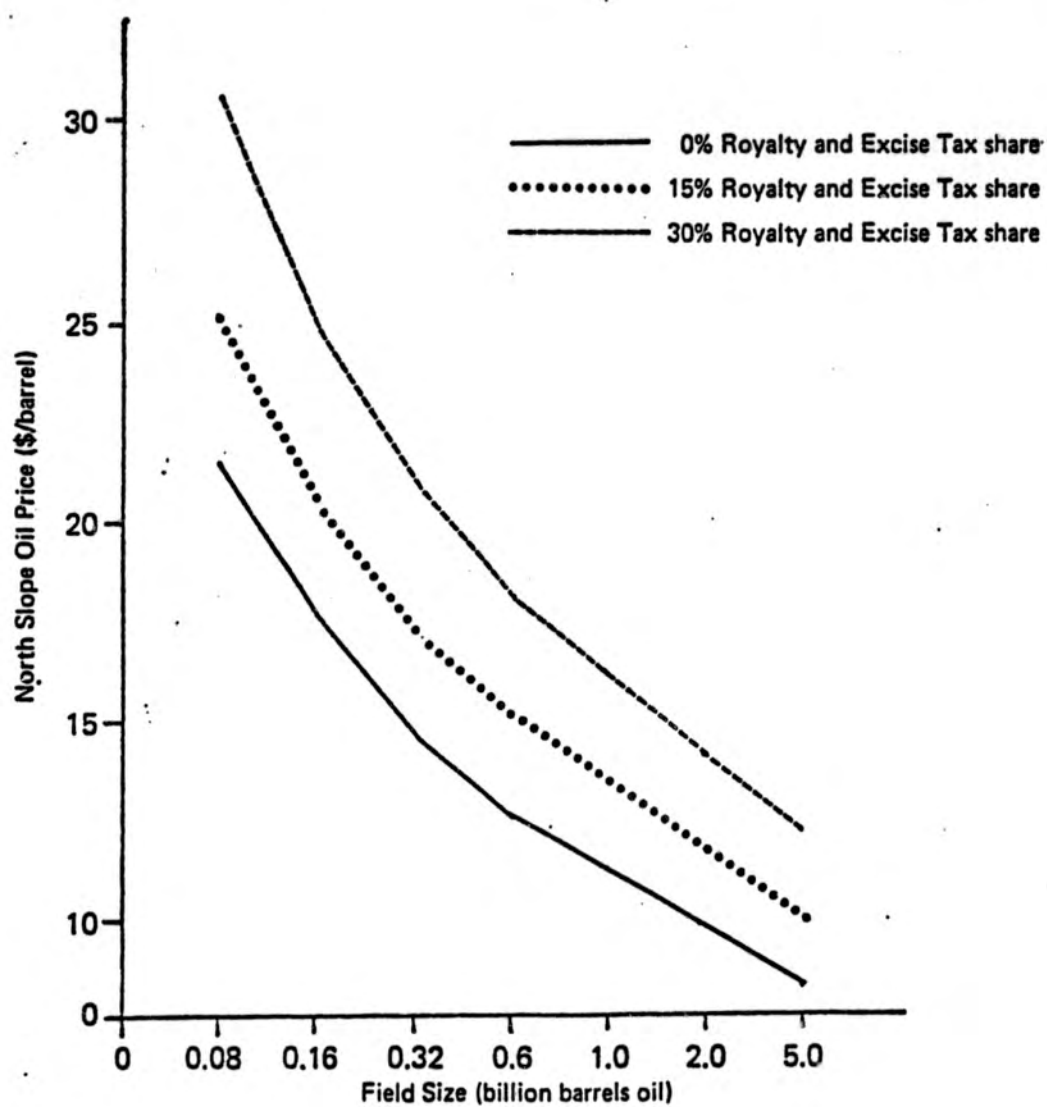
Figure 6 illustrates the effect of three alternative rates of royalty and excise taxation (excise shares) on the margin of development, applying the mid-range cost scenario to the simple model discussed here. The figure shows the margin as a tradeoff between the minimum size field that can be developed at a profit and the price of oil, given three alternative excise shares. Larger fields are feasible to develop at a lower price than smaller ones because of the economies of scale assumed in development costs.

At this lower minimum economic price, the margin of production is lower than it is with a higher oil price, indicating that the ultimate recovery rate from a marginal field falls as the minimum economic field size increases. Smaller fields need a higher price to assure feasible development, which is associated with a higher recovery rate of the more limited reserves. The rate of recovery of original oil in place at the margin of development, with the assumed maximum technical recovery of one-third, ranges from around 29 percent for the smaller fields represented in Figure 6 to around 25 percent for the largest fields.

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Under economic conditions prevailing on Alaska's North Slope, and assuming a real wellhead price of \$15 per barrel, minimum field sizes range from around 300 million barrels of recoverable oil at a 0 percent excise share to around 1.5 billion barrels at a 30 percent excise share. At a \$20 per barrel real wellhead oil price, the range is from 100 million barrels for no royalties or excise taxes

Figure 6. Frontier Alaska Minimum Economic Field Size, Mid-Range Cost Scenario



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to around 500 million barrels with a 30 percent excise share. State leases typically contain excise shares of 20 to 30 percent of production, not counting the federal Windfall Profits Tax (North Slope production is exempt except for the Prudhoe Bay field).

Figure 7 illustrates the margin of production for the same three excise shares with the extreme high cost scenario. This cost scenario, which might represent OCS development in the Navarin Basin, requires much higher wellhead prices to allow for profitable development. The figure shows the difficulty of developing even very large fields at a wellhead oil price substantially less than \$25 per barrel. At the \$25 per barrel real wellhead price, minimum field sizes range from around 600 million barrels with no royalty or excise tax to 2 billion barrels with a 30 percent share. Even a 15 percent excise share (royalty rates for OCS lease sales are typically either one-eighth or one-sixth) raises the minimum developable field size from 600 million barrels to around 1 billion barrels, as shown in Figure 7.

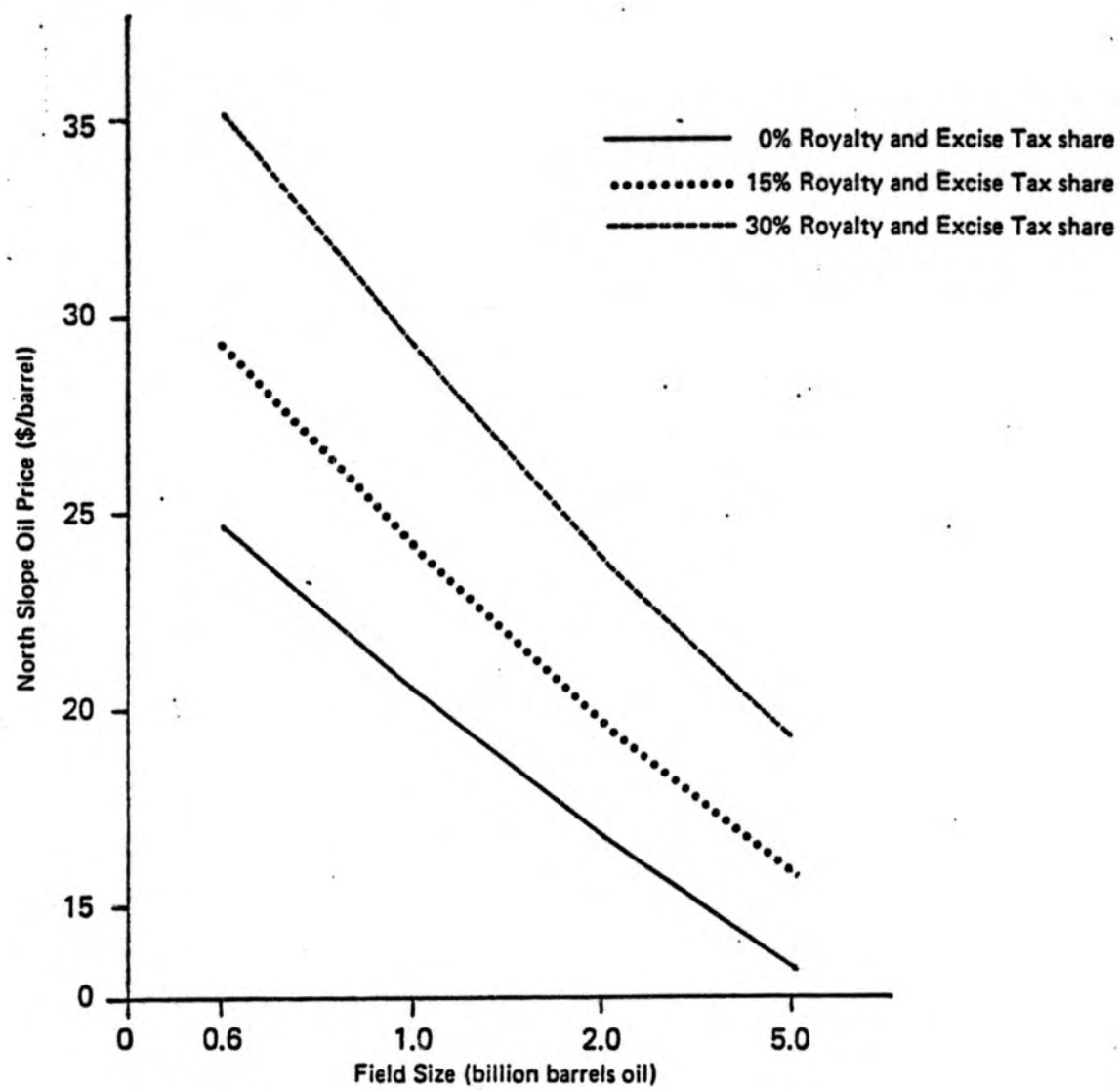
We do not show the comparable margin of production computed from the low cost scenario. Even for fields of less than ten million barrels, a 30 percent excise share allows profitable development at \$20 per barrel, and a \$25 price per barrel allows development with a 45 percent excise share. It is significant to note that for a region such as onshore Texas, where costs are an order of magnitude lower than those prevailing in Alaska, the effect on minimum economic field sizes of normal excise shares ranges in the thousands rather than in the millions of barrels of recoverable reserves.

With these simple examples, it should now be clear that excise shares have a very large potential impact on the margin of development in high-cost frontier areas. Oil fields discovered but not developed due to the effects of attempts by landowners and governments to collect economic rent in the form of royalties and excise taxes represent losses of production and economic rent, not to mention government revenues.

At the margin of development, there are no net profits to share with net profit share lease payments, even though there may be a substantial royalty and excise tax liability. Under the assumption of low risk to development investments, net profit shares do not affect the minimum economic field sizes, just as they leave unaffected the margin of production. When development of new fields involves a high degree of risk, high net profit shares may affect the margin of development due to the following reason.

If the price of oil were to fall or if development costs were to rise so much that the decision to develop the field turned out to be a costly mistake, producers would bear the entire loss.¹⁴ On the other hand, if profits from developing the field were higher than anticipated, the producers would have to share a portion of the

Figure 7. Frontier Alaska Minimum Economic Field Size, Extreme Cost Scenario



"windfall" with the landowner. The potential for producer losses from developing an unprofitable field, together with the asymmetry of net profit share lease payments, causes the minimum economic field size to rise where development risks are high.

Of course, the impact of excise shares on the margin of development with this type of risk is at least as great as the impact of net profit shares, as we show below with reference to the margin of exploration. Once a field has been discovered, net profit shares in leases, even at high rates, are associated with relatively little loss of potential production, economic rent, or petroleum revenues.¹⁵

Effect on the Margin of Exploration

We have noted that royalty shares and excise taxes may have a very large impact on minimum field sizes for profitable development (margin of development) but that their impact on oil recovery caused by early abandonment of producing fields (margin of production) may have been exaggerated. We have also noted the minimal effects of net profit share lease payments on the margins of development and production. While net profit shares are like bonus payments in that they do not affect low-risk development and production decisions for known oil and gas fields, they may affect the high-risk decisions of producers. Petroleum exploration in frontier areas is such an activity associated with a high risk of failure.

We now show an example of the effects of net profit share lease payments relative to those of royalties and excise taxes on the margin of exploration with an extension of the simple petroleum development model. We start by assuming that if oil is present in an unexplored area, we have a probability distribution for finding the oil concentrated in a field of a given size. We express the conditional probability distribution as a discrete probability, P_i , that oil (if present) will occur in size class i .

The present discounted value of developing each hypothetical field in the distribution if oil is present is given by $V - C$, from equations (8) and (11) above. However, the producer incurs costs of exploring the basin regardless of whether or not a discovery is made which allows profitable development. With net profit share leasing, the producer pays net profit shares to the landowner only if there are net profits to share. One may write the conditional development value for the hypothetical field of size class i , D_i , as a three-part function:

$$D_i = \begin{cases} E; & \text{if } V \leq C \\ V - C - E; & \text{if } V - C \leq E \\ (1-s)(V - C - E); & \text{if } V - C > E \end{cases} \quad (12)$$

where E represents fixed exploration costs and s is the net profit share rate.

The exploration value of the area to the producer becomes the sum of the conditional development values, D_i , multiplied by their probability of occurrence, or

$$X = M \sum_i P_i D_i \quad (13)$$

where X is the risked (or unconditional) value to the producers of exploring the area, and M represents the probability oil is present in the basin. The variable M corresponds in definition to the "marginal probability" used by the U. S. Geological Survey. For any given price of oil, the margin of exploration is the minimum probability of finding oil, M , which yields a positive expected exploration value, X .

We have computed an illustrative example of the relative effects of excise shares and net profit shares on the margin of exploration, using the mid-range cost scenario and a \$15 wellhead oil price to represent Alaska North Slope conditions.¹⁶ Figure 8 shows the effect of excise shares and net profit shares on the exploration value assuming $M = 1$, that is, assuming producers are certain that oil is present somewhere in the exploration area. In the example of Figure 8, net profit shares have roughly the same impact on the value of exploration property as a royalty and excise-tax share that is somewhat less than one-half as large. In other words, a combination of royalties and excise taxation that added to 25 percent of the gross value of production would have around the same value to producers as if the same area were leased with a 60 percent net profit share and no royalty or excise tax. The traditional one-eighth royalty roughly matches the effects on exploration values of a 30 percent net profit share.

The computation of the exploration value, X , would be analogous to the method producers use to prepare their bids for a lease sale. In a highly competitive sale, the landowner would receive most of the exploration value in the winning bonus bid, if that were the bidding method chosen for the sale. Thus, another interpretation for Figure 8 is that it represents the relative effect net profit shares and royalty and excise tax rates have on bonus bids expected from leasing a hypothetical unexplored area.

The margin of exploration in this example is the marginal probability that oil is present, M , at which the exploration value, X , is exactly zero. Figure 9 illustrates the margin of exploration as a tradeoff between the maximum excise share or net profit share and the marginal probability which allows exploration to proceed. The figure shows a similar pattern to that of Figure 8, with royalty and excise tax shares of gross production having the same discouraging effect on exploration as net profit shares more than twice as high.

Figure 8. Effect of Royalty and Net Profit Shares on Value of Exploration Property, Hypothetical Frontier Alaska Region

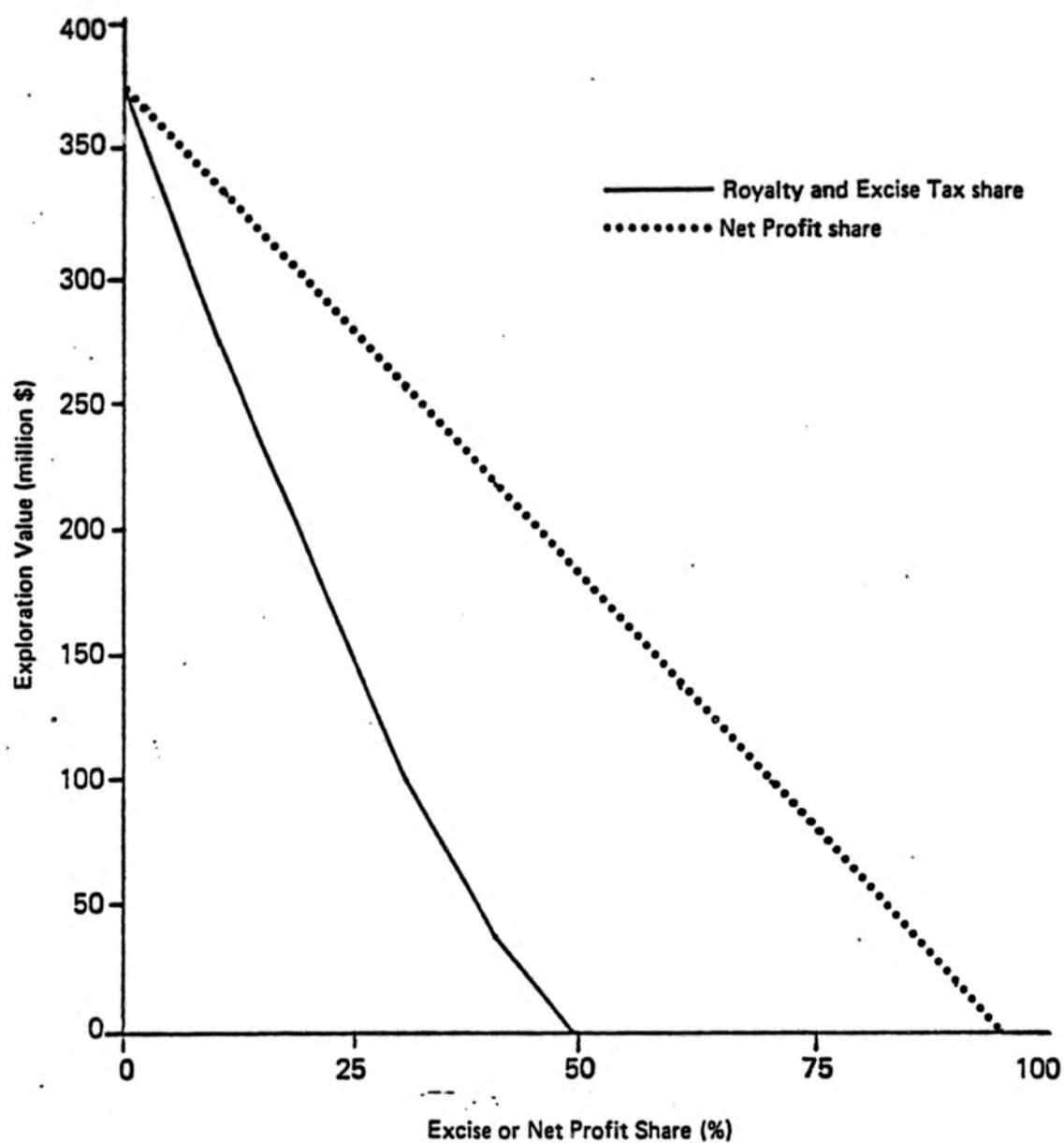
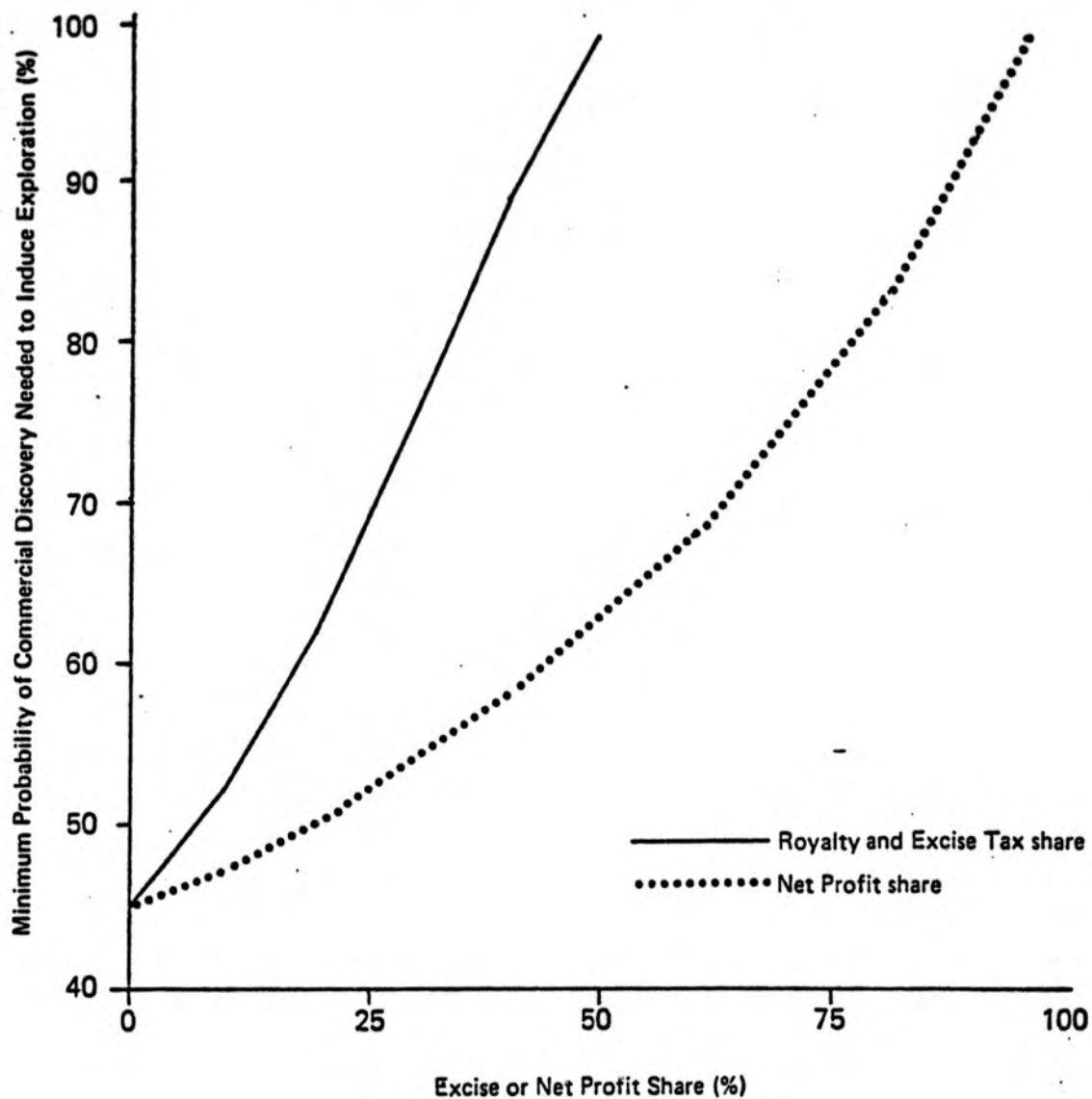


Figure 9. Effect of Royalty and Net Profit Shares on Margin of Exploration, Hypothetical Frontier Alaska Region



Producers wish to explore an area for potential oil and gas development if they believe the probability of finding oil is at least as high as the appropriate curve in Figure 9. If the area is offered for lease with bonus bids, there will be no bids if the marginal probability for the area lies below the curve. However, if the leases are offered on a royalty bidding or net profit share bidding system, Figure 9 shows the highest level bids may reach, depending on the probability that oil is present in the area as evaluated by the bidders.

In a leasing situation where bidders can set the excise share and/or the net profit share as a bid variable for each tract, competition would drive the bids toward, but not past, the curves for the margin of exploration shown in Figure 9. Bidding for net profit shares, then, typically has the same minimal effect on the margin of exploration as it has on the margin of development, and no effect on the margin of production. Royalty bidding would not affect the margin of exploration directly. It would, however, affect the development margin indirectly through the strong effects noted for the margin of development and the additional effect noted for the margin of production.

Potential Magnitude of Effects on Oil Development

In the next chapter, we examine more closely the effect of royalties and excise taxes on the economic margin in the context of specific known but as yet undeveloped oil fields on Alaska's North Slope. We can also assess more generally, however, the order of magnitude of effects on future production from frontier Alaska areas which have not yet been fully explored. As before, we address the problem in terms of effects resulting from shifting the margin of production, the margin of development, and the margin of exploration.

Changes in the Margin of Production

We have noted that the traditional royalty share of one-eighth of gross production would likely cause abandonment of fields approximately one year earlier than would be the case if there were no royalty. In a frontier area with relatively high operating costs, a one-year earlier abandonment would mean a loss of perhaps 3-5 percent of potential oil recovery from a marginal field. For a field in a lower operating-cost region such as Cook Inlet (or Texas), or for a very large field in a frontier area, early abandonment caused by a one-eighth royalty would be less than one percent of reserves.

The effects are significant but not especially large when one considers excise taxes and the possibility of higher royalty rates in the analysis. A 30 percent excise share may cause a producing field to shut down as much as three years earlier than if there were

no excise taxes or royalties. This might mean a potential loss of 10-15 percent of reserves from a very high-cost field, but only 2-5 percent from very large fields or fields in nonfrontier regions. The economic limit factor in the Alaska severance tax, which reduces the effective rate to zero near the margin of production, may possibly save 3-5 percent of production from a high-cost frontier field from the mitigating effect on the margin of production.

Changes in the Margin of Development

The adverse effects noted above on potential oil production resulting from changes in the margin of production apply to fields which are feasible to develop under the prevailing royalty and excise tax regime. The analysis using the simple petroleum development model discussed above suggests that the effect of changes caused by excise shares on the margin of development is much more significant. Using the mid-range frontier development cost scenario, a \$20 real wellhead price would permit profitable development of a 100-million-barrel field with no royalty or excise tax. With a 30 percent excise share, the minimum field size would be 500 million barrels.

The number of fields occurring in the size range of 100 to 500 million barrels, for example, and the total recoverable oil contained in these fields will not be known until all areas in Alaska with favorable geology are fully explored. One could, however, obtain a benchmark figure for the size distribution of oil and gas reserves by initial field sizes obtained by analogy to mature producing regions. A major study of significant oil and gas fields in the United States provides such an analogy.¹⁷

By 1976, 137.2 billion barrels of recoverable crude oil reserves had been discovered in the United States, excluding the North Slope region of Alaska (for which data were mostly unavailable at the time of the study). Nearly 39 percent, or 53.1 billion barrels of all crude oil reserves ever discovered, occurred in fields with initial reserves greater than 500 million barrels. Development of these fields would likely be feasible in a region such as the North Slope, even with an excise share as high as 30 percent.

Approximately 21 percent of the oil occurred in concentrations of 50 million barrels or less. Fields in this size range are unlikely to be feasible in remote areas, even without excise shares. Slightly over 40 percent of the oil ever discovered, or 55.4 billion barrels, was present in concentrations ranging from 50 to 500 million barrels, including 19.3 percent in fields between 200 to 500 million barrels, and another 12.3 percent in fields between 100 to 200 million barrels in size.¹⁸ It is in this size range that the greatest potential exists for loss of oil recovery due to changes in the margin of development.

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The U. S. Geological Survey mean estimate of undiscovered recoverable oil occurring onshore in Alaska is around 6.9 billion barrels, with a 90 percent confidence interval ranging from 2.5 to 14.6 billion barrels. The mean recoverable oil resource estimate for offshore Alaska is 10.9 billion barrels, with a 90 percent confidence interval ranging from 3.8 to 22 billion barrels (ignoring currently infeasible areas with a water depth greater than 200 meters). Approximately 13 billion barrels of offshore and onshore oil in the mean estimates are expected to occur north of the Brooks Range.¹⁹ An independent study by the National Petroleum Council confirms this expected pattern of discoveries, estimating mean technically (but not necessarily economically) recoverable reserves of 8.2 billion barrels from the Beaufort Sea and 6.5 billion barrels onshore on the North Slope.²⁰

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We may use these undiscovered resource estimates to illustrate the order of magnitude of the loss of potential production due to the effect of royalty shares and excise taxes on the margin of development. We noted above that nearly one-third of total U.S. oil reserves, excluding Alaska's North Slope, occurs in fields containing originally between 100 and 500 million barrels. Applying this U.S. average distribution of reserves by field size to the estimates of undiscovered recoverable oil resources, a mean estimate is that 4-5 billion barrels of oil occur north of the Brooks Range in fields between 100 and 500 million barrels. At least one-half of these undiscovered reserves are likely to remain undeveloped due to the effects of the prevailing royalty and excise tax rates on the margin of development.

Summary

The preceding analysis has shown that from a standpoint of minimizing the adverse effects on production and on the size of economic rent, net profit share payments have comparatively little impact, and bonus payments have virtually no impact. The effect net profit shares have on the margin of exploration can be greatly diminished in the leasing process by having the producers bid for the net profit shares with a low fixed bonus payment rather than the reverse, as is commonly done in Alaska.

Royalty shares and excise taxes such as state severance taxes and the federal Windfall Profits Tax are similar in their effects on reducing potential petroleum production and economic rent. The effect of royalties and production taxes on minimum economic field sizes is particularly a cause of concern. The findings strongly suggest that the state and federal governments should consider substituting net profit shares for royalty shares in frontier areas and offering more net profit share lease sales. The analysis also suggests that the savings in oil recovery attributable to the economic limit factor in the Alaska severance tax is much smaller than the loss from discouraging development of new fields potentially resulting from the high nominal rate.

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ENDNOTES TO CHAPTER IV

¹See, for example, Albert M. Church, Taxation of Nonrenewable Resources, Lexington, Mass: Lexington Books, 1981.

²Stephen L. MacDonald, The Leasing of Federal Lands for Fossil Fuel Production, Baltimore: The Johns Hopkins Press for Resources for the Future, 1979.

³See Albert K. Smiley, Competitive Bidding Under Uncertainty: the Case of Offshore Oil, Cambridge, Mass: Ballinger Publishing Company, 1979, for a technical analysis of the effects of number of bidders on expected rent.

⁴Two relevant international studies are Kenneth W. Dam, Oil Resources, Who Gets What How, Chicago: University of Chicago Press, 1970; and Kamal Hossain, Law and Policy in Petroleum Development: Changing Relations between Transnationals and Governments, London: Frances Pinter Ltd., 1979.

⁵Lease rental payments can be avoided by forfeiting the lease back to the landowner, raising the possibility of minor effects on the margin of exploration. Both fixed lease rental payments and administratively-set minimum bonus levels may turn away potential exploration initiatives, affecting the margin of exploration.

⁶The Alaska severance tax has a payment structure in which the effective rate decreases as production per well decreases due to the economic limit factor formula. Thus, the tax is not exactly proportional to the rate of production. The federal sliding scale royalty lease also has a royalty rate which may increase as production from a lease increases. However, we consider their effects similar to those of constant-rate excise taxes since the payments are still based upon a share of total production rather than on income, property, or other accounting base.

⁷The state of Alaska offers "incentive drilling credits," providing income tax credits for up to 40 percent of certain exploration costs. These credits have often been extended for net profit share leases, mitigating the asymmetric treatment of gains and losses discussed for this system.

⁸See the discussion of the Alaska petroleum property tax in Chapter II. We ignore property taxes on oil and gas reserves, or reserves taxes. The revenue base for this tax is a measure of expected future income from the lease or property, which is also a fixed cost from the standpoint of investment decisions.

⁹Hayne E. Leland, An Analysis of Sliding Scale Royalties, Alaska Department of Natural Resources, August 1981, noted comparable minor effects on early abandonment arising from high fixed royalty shares using a similar petroleum economic model.

¹⁰John Lohrenz, "Severance Tax Impact Often Misinterpreted," Oil and Gas Journal, June 18, 1984, 133-137, made a similar assumption for an analysis of the distorting effects of excise taxes on development decisions, yielding results consistent with those reported here.

¹¹In the special case of a scale factor, m , of 1.0, this is the problem treated by Hayne Leland, op. cit.

¹²The values assumed for the cost parameters for the model are shown below as follows:

<u>Parameter</u>	<u>Low</u>	<u>Mid-range</u>	<u>Extreme</u>
c_1	1.0	2.0	3.0
k_0	0	100	1500
k_1	55	110	165
m	.75	.75	.75

We also assume the discount rate (real pre-tax minimum rate of return to total capital) δ , is 15%, that there is no trend in real oil prices, and that the maximum technical recovery rate, R , is one-third of initial oil in place. The equation system was solved for the margin of development using the TROLL simulation software. The solution is relatively simple, however, given any assumed value for the variable λ , so that the system is easily solved using BASIC software available on any microcomputer.

¹³This is consistent with results obtained by both Leland, op. cit., and Lohrenz, op. cit.

¹⁴Net profit share provisions which amortize exploration and development costs over a production scenario rather than allowing for full capital recovery before profit sharing begins cause even greater losses in this instance. They would, consequently, lead to a larger adverse effect on the margin of development in situations with high development risks.

¹⁵Some critics of net profit share leases argue that high net profit shares reduce incentives for cost control by the producers (see, for example, Walter J. Mead, Asbjorn Moseidjord, and Dennis Muraoka, "Alternative Bid Variables as Instruments of OCS Leasing Policy," Contemporary Policy Issues, Western Economic Association, forthcoming). Although there might be some loss in government revenue from attempts by net profit share lessees to hide revenues

and inflate accounting costs on net profit share leases, there are no incentives from a financial standpoint for the producers to change development and operating plans.

¹⁶The development and operating cost assumptions used for these calculations are the same as for the mid-range cost scenario shown in Figure 6. Fixed exploration costs were set arbitrarily at \$300 million. The hypothetical distribution of field sizes, P_i , was:

Q (initial oil in place) P_i billion barrels)	
0.03	0.10
0.06	0.09
0.12	0.08
0.24	0.07
0.48	0.06
0.96	0.05
1.8	0.04
3.0	0.03
6.0	0.02
15.0	0.01

¹⁷Richard Nehring and E. Reginald Van Driest II. The Discovery of Significant Oil and Gas Fields in the United States, Santa Monica: Rand Corporation, 1981, 67-71.

¹⁸Nehring, Ibid., p. 70.

¹⁹Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States, U.S. Geological Survey Circular 860, Washington, D. C.: U. S. Government Printing Office, 1981.

²⁰U.S. Arctic Oil and Gas, Washington, D.C.: National Petroleum Council, 1981.

CHAPTER V

ALASKA PETROLEUM PRODUCTION AND REVENUE PROJECTIONS AND THE INFLUENCE OF FEDERAL POLICY

Introduction

This chapter discusses alternative projections for Alaska state petroleum production and revenues over approximately the next twenty to twenty-five years. The purpose of the analysis presented here is not to offer a competing set of revenue projections to those published quarterly by the Alaska Department of Revenue. On the contrary, we seek to analyze some of the major factors which might affect such projections, with the goal of defining the sensitivity of production and revenue projections to market price and public policy factors. We focus on the effects of federal policy toward the oil and gas industry in Alaska and nationwide, but consider possible state responses to certain hypothetical federal initiatives as well.

We consider several exemplary federal policy initiatives. These include (1) limiting state severance taxes, (2) permitting export of North Slope oil, and (3) extension of the federal Windfall Profits Tax and eliminating the exemption for certain Alaska production. Although the primary emphasis is on production onshore and from state offshore lands, we also consider for comparative purposes the potential role of production from the Alaska federal OCS.

Scope of Analysis

The analysis primarily focuses on production from the North Slope region of Alaska. Currently over 95 percent of the state's oil production occurs in this region, and its predominance is likely to continue for the foreseeable future. Cook Inlet oil production has been declining steadily and is not a significant factor in state revenue projections.¹

We concentrate on the development of known fields on the North Slope. More oil will almost certainly be discovered in the region and begin producing by the year 2000. On a quantitative basis, the most promising areas within state jurisdiction are either offshore or within the boundaries of the Arctic National Wildlife Range. Exploration is just beginning in the wildlife range, and adjacent offshore areas have not yet been leased. While large discoveries may occur from exploration in these areas, the lengthy permitting process and the high cost of access will most likely defer production beyond the year 2000.

Market prices and public policy will affect the location and intensity of industry exploration. This is the effect on the margin of exploration, as discussed in Chapter IV. Alternative price and policy scenarios would be associated with changes in the exploration effort, timing of discoveries, and commencement of production. Major impacts on production resulting from changes in industry exploration effort would again be deferred until after the turn of the century. We do not attempt to quantify this potential effect.

We do, however, explicitly analyze how the margin of development for major known North Slope fields may affect Alaska state petroleum revenues up to around the year 2000. Although we do not attempt to project what total Alaska petroleum production and revenues might be after 2000, we carry the analysis of the individual North Slope fields to 2010.

Until discoveries are confirmed for federal waters on the North Slope or elsewhere on the Alaska OCS, insufficient information exists from which to analyze the effects of prices and policies on the margin of development. Commercial discoveries and subsequent production are likely to occur both off the north and west coasts of Alaska, however. Although the state receives no direct revenues from OCS production, it would be inappropriate to ignore entirely the future role of OCS production and revenues. Our approach is to consider for comparative purposes a hypothetical production and royalty revenue scenario based upon lease-sale planning information compiled by the Minerals Management Service.

We ignore the potential role for natural gas in the production and revenue scenarios analyzed below, assuming that the region's vast quantities of natural gas are useful only to support oil production-related activities. If a transportation system is ever built to market Alaska North Slope gas, the high cost would virtually assure that the wellhead price and, hence, the economic rent from production would be inconsequential. Natural gas discoveries from federal leases in the Bering Sea would likewise be uneconomical to produce under reasonable cost and world market price scenarios.²

Methodology for Projecting Alaska North Slope Production and Revenues

The objective of this section of the study, as mentioned above, is to project the sensitivity of Alaska petroleum production and revenues to certain specific assumptions about market prices and federal policy. This requires an analysis of changes in the economic feasibility of potentially producing oil fields (margin of development) under a number of assumptions about size of reserves and cost of production as well as price and policy factors.

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Thus, the methodology of our comparative projections involves a two-step process. First, we determine if development of a given new field would be economically viable under the set of assumptions associated with the particular scenario. Then we add up production and revenues from fields calculated to have positive development values to derive the total regional projections.

We use an accounting model, FINDOIL, to perform the discounted cash flow analysis of each field under the various scenarios. This model has an accounting structure nearly identical to the historical accounting model, HISTOIL, used for the historical analysis in Chapter III, except that it discounts all cash flows (at a 10 percent real annual rate) to 1984 values. Appendix F contains a listing and documentation for the model FINDOIL along with the exact assumptions used for each selected North Slope field. We discuss the assumptions used for the base case and sensitivity projections in general terms below.

North Slope Petroleum Assumptions

Industry sources estimate total oil in place in the vicinity of the Prudhoe Bay field to be around 60 billion barrels. This total includes 23 billion barrels of original oil in place in the Prudhoe Bay field, 5.5 billion in the Kuparuk River zone, and 3 billion in the Lisburne. In addition, West Sak and Ugnu heavy oil zones overlying the Kuparuk field have between 21 and 36 billion barrels of oil in place. Known oil resources on the North Slope outside the immediate vicinity of Prudhoe Bay may bring the total oil in place in the region to 80 billion barrels.³

We derive production scenarios for the North Slope region from hypothetical development patterns for nine fields or development zones. These include the currently producing Prudhoe and Kuparuk fields as well as seven fields in various stages of the feasibility study by the industry. We explicitly consider multiple options for development of four of the nine fields, assuming optimistically that any technological problems encountered are overcome. A brief description of each of the selected fields follows. Table F.1 in Appendix F contains the complete set of assumptions defining the parameters of each development option considered for each field.

Prudhoe Bay: We assume an average production rate of 1.534 million barrels per day from Prudhoe through 1987. In the basic projection, production declines to 1.054 million barrels per day in 1990, and to just over 300 thousand barrels per day in 2000. When we include the effects of the miscible-gas enhanced-oil recovery project, production would decline somewhat more slowly so that total recovery by 2000 increases by around 115 million barrels.

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Kuparuk: We consider development of the field in two discreet stages. Stage 1 describes the currently-productive zone while Stage 2 refers to the zone of ongoing assessment and construction of development facilities to exploit the Kuparuk River producing zone. Total recoverable reserves for this development area are just over one billion barrels of oil. We assume peak production rates from each stage conservatively at around 110 thousand barrels per day, with production from the second stage possible by 1985.

Lisburne: Arco has been testing development wells in the Lisburne pool underlying the Prudhoe Bay field since 1982. We assume recoverable reserves of around 450 million barrels for this development prospect, with production possible by 1987 and reaching 100 thousand barrels per day.

Milne Point: We examine two stages for development of the smaller Milne Point prospect. The first would target primarily the Kuparuk pay, which might begin producing in 1986, while the second stage would produce from the overlying West Sak pay, beginning in 1990. Peak production from each development stage would be around 30 thousand barrels per day, with recoverable reserves around 100 million barrels from the combined project.

Endicott: If successfully developed, the Endicott River area may provide production of 85 thousand barrels per day, with a startup date in 1987. Although much larger amounts of oil are present in the vicinity, we assume recoverable reserves of around 300 million barrels.

Gwydyr Bay: Production from this smaller North Slope field could start at 10 thousand barrels per day with reserves of around 30 million barrels. Production could start as early as 1987 if a decision is made soon to develop the field.

Flaxman: As much as 600 million barrels of oil may be recoverable in the Point Thompson-Flaxman Island area east of Prudhoe Bay. More than one-half of this amount, however, is more appropriately described as gas condensate in the giant Point Thompson gas field. We assume the gas field is not feasible to develop in any of the scenarios. However, we do consider development of less than 300 million barrels in a Flaxman field. Oil production might begin by 1990, with a peak flow rate of 80 thousand barrels per day.

Seal Island: Shell has recently confirmed a discovery in state and disputed state-federal waters in the Beaufort Sea with two wells yielding 5,000 barrels per day of 40-degree gravity oil. The new field may begin production by 1992, with total recovery eventually exceeding 300 million barrels. We assume a peak production rate of 85 thousand barrels per day and that the jurisdictional dispute is resolved in favor of the State of Alaska.⁴

X

West Sak: We consider two alternative phases for potential large-scale commercial development of shallow Cretaceous heavy oil deposits near the Kuparuk producing area. Phase I covers the area immediately overlying the Kuparuk, with which some development facilities and costs could be shared. This phase might begin in 1989, recovering as much as 750 million barrels if production is economically viable, with peak production reaching 150 thousand barrels per day. The second phase essentially covers additional development of four times as large a resource, possibly beginning in 1992, with higher costs due to the need to construct additional development facilities.

Scenarios

We project North Slope production and revenues under eight different scenarios. There are essentially three types of scenarios considered, in addition to the base case, for examining the sensitivity of production and revenues. We consider first two alternative market price scenarios to compare to the base case. Next we examine three scenarios of federal policy related to market prices of North Slope oil. Finally, we consider two alternatives associated with federal limitations to state severance taxes.

The eight scenarios chosen cover only a small fraction of the potential variation in market and policy factors affecting Alaska North Slope production and revenues over the next several decades. Nevertheless, we believe that they represent the likely range of opportunities and outcomes. The following paragraphs define the scenarios used for the alternative projections.

Base case scenario: For the base case scenario, we have assumed a constant real wellhead oil price prevailing throughout the projection period, 1983-2010. The base price projected for Prudhoe Bay is \$17.50 in 1984 dollars and \$16.00 for Kuparuk. This is a conservative price projection, due in part to the likely decline over time in the TAPS tariff, at least in real dollars. The tariff has been under continuous litigation but a resolution is not in sight, however. Thus, we might think of the base case price projection as a risk-adjusted, middle-range scenario. The base case assumes no change in current federal and state tax structures, with the federal Windfall Profits Tax beginning its phaseout at the latest possible date, in 1991.

Market price scenarios: The purpose of these scenarios is not to estimate the sensitivity of production to small changes in the wellhead price since the information available is not sufficient to make an accurate assessment. Rather, we choose a low price and a high price scenario to bracket the likely range of outcomes. The low price scenario assumes a constant real market price schedule \$7.50 per barrel less than that currently prevailing on the North Slope, or \$10 per barrel for Prudhoe Bay oil. This price

corresponds roughly to a world price of \$20 per barrel, which might be associated with the collapse of OPEC. The high price scenario assumes a constant real price \$7.50 per barrel greater than the current price, or \$25 for Prudhoe Bay oil. This is roughly the same real price as prevailed in 1981 at the peak of OPEC's market power.

Federal price policy: A major discriminatory federal action against Alaska petroleum producers and the state is the policy preventing export of oil carried through the Trans-Alaska Pipeline. The economic effect on Alaska petroleum production of lifting the current restriction is unclear at this point since it is not certain how producers and the state would choose to react to the foreign market opportunities, if they were available. It is most likely that a large portion of North Slope oil would continue to supply domestic markets. We assume for the sake of the discussion scenario that the opportunity to export North Slope oil leads to an increase in the average wellhead price of \$2.50 in 1984 dollars.⁵

Another area of federal petroleum industry policy of great concern in the past has been direct wellhead price controls. Oil price controls are unlikely to reappear under current or weaker market conditions. Gas price controls are largely irrelevant to the North Slope region. Re-emergence of price controls is possible under a scenario of renewed supply disruption. More likely, however, Congress would simply extend the life of the Windfall Profits Tax, as much for its revenue-raising potential as for its redistributive role.

North Slope prices in the base case are low enough so that the Windfall Profits Tax has very limited impact. We consider two scenarios, however, in which the Windfall Profits Tax is not only extended through 2010, but the exemption from taxation is eliminated for non-Prudhoe North Slope oil. One scenario combines the extended Windfall Profits Tax with the high price scenario, the other with the export scenario.

Tax policy: A number of recent congressional initiatives have surfaced which attempt to set a federal policy toward state production taxes on oil and gas. These include a proposed national severance tax of around \$3 per barrel of oil and proposals to limit state severance taxes.⁶

The Windfall Profits Tax already exists as a federal excise tax on oil production, and attempts to prolong its life or even increase effective rates are more likely to succeed than imposition of a new tax. In any event, a national severance tax of, say, \$3 per barrel, if it were applied to state royalty shares as well as private production, would be similar in its effects to a \$3 reduction in the market price.

We consider instead two scenarios associated with a relatively benign hypothetical initiative to limit state severance taxes to a nominal rate of 10 percent. We assume that the State of Alaska would react to such a law to reduce the severe fiscal impact resulting from the potential loss of one-third of its severance tax revenue. In one scenario, the state rewrites the severance tax law to eliminate the economic limit factor, so that the effective rate remains at the 10 percent ceiling.⁷ In the other, the state wins court approval and reinstates the separate accounting method of assessing petroleum corporate income taxes. The separate accounting method assesses the Alaska Corporate income tax rate of 9.4 percent on income earned within the state from oil and gas production and transportation activities. The tax was repealed in 1981 under pressure of litigation. This scenario assumes the severance tax structure stays intact, except for a reduction in the nominal rate to 10 percent.

North Slope Oil Production and Revenue Scenarios

Base case results: Table 35 summarizes cumulative production, after-tax profits, total economic rent, oil royalties and excise tax payments, and total investment costs for each of the nine fields, including the separate stages of possible development, where appropriate. The cumulative value figures are discounted cash flows in 1984 dollars using a 10 percent real discount rate, the same rate used for the historical analysis in Chapter III.

Present discounted value of after-tax profits is negative for the Flaxman, Gwydyr Bay, and both West Sak developments, suggesting that they are not feasible under current economic conditions. The Endicott and both Milne Point projects yield only a very small margin of profitability. The miscible-gas enhanced-oil recovery project at Prudhoe appears feasible. Despite its addition of well over \$100 million in economic rent, it adds only a few million dollars to the enormous present value of profits.

Table 36 shows projected North Slope oil production under the base case assumptions for the six fields for which development is feasible (including the enhanced oil recovery project at Prudhoe). Oil production figures for three of the fields--Gwydyr Bay, Flaxman, and West Sak--are zero throughout the period, indicating that production is not profitable under the base case price and field development assumptions. Only two fields, Prudhoe Bay and Seal Island, would still be producing in 2010, according to the projections.

Total oil production, state petroleum revenues, and federal revenues summed over the producing fields in the base case projection are shown in Table 37. The table shows annual production peaking at 680 million barrels in 1987, declining to around 400 million barrels in 1993 and to 169 million barrels in 2000.

TABLE 35
CUMULATIVE OIL PRODUCTION AND DISCOUNTED VALUE, 1983-2010
BASE CASE PROJECTIONS

(millions of 1984 dollars)

<u>FIELD</u>	<u>CUMULATIVE OIL RECOVERY (MILLION BBLs)</u>	<u>AFTER TAX PRODUCER PROFITS</u>	<u>TOTAL ECONOMIC RENT</u>	<u>ROYALTIES AND EXCISE TAXES</u>	<u>TOTAL FIELD INVESTMENT COSTS</u>
ENDICOTT	305.667	8.913	104.64	591.305	1804.25
FLAXMAN	250.668	-22.61	-133.84	230.546	1154.76
GWYDYR BAY	28.092	-54.067	-158.089	34.847	312.86
KUPARUK (I)	437.236	770.211	3002.4	868.512	903.339
KUPARUK (II)	457.311	663.003	1565.17	704.012	1573.67
LISBURNE	379.611	457.681	1039.67	456.6	1069.68
MILNEPOINT (I)	49.571	5.749	36.628	115.841	300.244
MILNEPOINT (II)	52.1	6.033	24.844	87.493	247.756
PRUDHOE BAY	6767.72	22288.1	61616.2	19213.3	9148.88
PRUDHOE EOR	6882.09	22290.6	61753.6	19490.2	9703.66
SEAL ISLAND	301.71	135.824	601.495	388.344	726.959
WESTSAK (I)	747.231	-110.266	-273.061	491.36	2204.08
WESTSAK (II)	3671.54	-2000.25	-5017.4	1586.71	10864.1

SOURCE: Appendix F, Tables F.2-F.13.

TABLE 36
PROJECTED ALASKA NORTH SLOPE OIL PRODUCTION: BASE CASE

(million barrels)

	PRUDHOE BAY	KUPARUK	MILNE POINT	LISBURNE	ENDICOTT	GWYDYR BAY	WEST SAK	FLAXMAN	SEAL ISLAND
1983	559.9	40.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1984	559.9	40.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1985	559.9	60.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1986	559.9	80.3	5.5	0.0	0.0	0.0	0.0	0.0	0.0
1987	559.9	75.8	10.9	18.3	15.5	0.0	0.0	0.0	0.0
1988	508.4	71.8	10.9	36.5	31.0	0.0	0.0	0.0	0.0
1989	448.7	68.3	8.2	36.5	31.0	0.0	0.0	0.0	0.0
1990	396.0	60.7	11.6	36.5	31.0	0.0	0.0	0.0	0.0
1991	349.4	53.9	15.5	36.5	27.3	0.0	0.0	0.0	0.0
1992	308.4	47.9	14.3	36.5	24.0	0.0	0.0	0.0	15.5
1993	272.1	42.5	8.2	31.9	21.1	0.0	0.0	0.0	31.0
1994	240.2	37.8	6.1	28.0	18.5	0.0	0.0	0.0	31.0
1995	211.9	33.5	4.5	24.5	16.3	0.0	0.0	0.0	31.0
1996	187.0	29.8	3.4	21.4	14.3	0.0	0.0	0.0	27.3
1997	165.0	26.5	2.5	18.7	12.6	0.0	0.0	0.0	24.0
1998	145.7	23.5	0.0	16.4	11.1	0.0	0.0	0.0	21.1
1999	128.5	20.9	0.0	14.4	9.7	0.0	0.0	0.0	18.5
2000	113.4	18.6	0.0	12.6	8.6	0.0	0.0	0.0	16.3
2001	100.1	16.5	0.0	11.0	7.5	0.0	0.0	0.0	14.3
2002	88.3	14.6	0.0	0.0	6.6	0.0	0.0	0.0	12.6
2003	78.0	13.0	0.0	0.0	5.8	0.0	0.0	0.0	11.1
2004	68.8	6.8	0.0	0.0	5.1	0.0	0.0	0.0	9.7
2005	60.7	6.0	0.0	0.0	4.5	0.0	0.0	0.0	8.6
2006	53.6	5.4	0.0	0.0	4.0	0.0	0.0	0.0	7.5
2007	47.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.6
2008	41.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.8
2009	36.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1
2010	32.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5

Source: Appendix F, Tables F.2-F.3.

TABLE 37
SUMMARY OF ALASKA NORTH SLOPE OIL
PRODUCTION AND REVENUES: BASE CASE

	TOTAL OIL PRODUCTION (MILLION BARRELS)	TOTAL STATE PETROLEUM REVENUES (MILLION 1984 \$)	TOTAL FEDERAL REVENUES (MILLION 1984 \$)*
1983	600.1	2894.6	1670.5
1984	600.1	2873.4	1997.2
1985	620.1	2921.9	2143.3
1986	645.7	2996.0	1944.1
1987	680.4	3140.1	2767.0
1988	658.8	3036.5	3021.7
1989	592.7	2728.9	2641.9
1990	535.7	2486.6	2381.5
1991	482.6	2233.8	2105.8
1992	446.6	2065.9	1872.9
1993	406.9	1880.1	1810.0
1994	361.5	1660.0	1604.2
1995	321.8	1321.9	1487.9
1996	283.2	1145.5	1336.4
1997	249.4	995.1	1154.2
1998	217.7	983.2	939.3
1999	192.1	851.4	820.6
2000	169.4	729.2	697.7
2001	149.4	633.5	596.7
2002	122.2	519.6	502.7
2003	107.9	442.5	424.9
2004	90.4	365.6	358.5
2005	79.8	308.3	300.5
2006	70.4	258.5	249.0
2007	53.9	194.3	208.1
2008	47.5	160.9	172.5
2009	41.9	133.0	140.5
2010	37.0	110.9	111.0

*Federal Windfall Profits Tax and Corporate
Income Tax.

Source: Appendix F, Tables F.2-F.13

Total state petroleum revenues in Table 37 include oil royalties, oil severance and conservation taxes, petroleum property taxes on production property, and Alaska corporate income taxes (apportioned share), but does not include the minor amount of revenues derived from gas production. Projected state revenues average around \$3 billion in 1984 dollars until 1989, then decline to \$2 billion in 1992 and to \$730 million in 2000. Federal revenues (Windfall Profits Tax and corporate income tax) derived from developing these North Slope fields show a remarkably similar pattern, although they are lower initially due to deductions for ongoing field development expenditures.

Market price scenarios: Table 38 summarizes total Alaska North Slope production and revenues for the low price case. In this case, only Prudhoe Bay production (without the enhanced oil recovery project) can cover fixed development costs. We assume production would also continue at Kuparuk (stage one only) since the major fixed costs have already been incurred there as well. Tables G.1 and G.6 in Appendix G show the individual results by field.

Total annual oil production in the low price case begins falling from 600 million barrels in 1987, dropping to just over 400 million barrels in 1990 and to 110 million barrels in 2000. Real state petroleum revenues would decline from a level of \$1.6 billion per year to \$1 billion in 1991, and to only \$240 million in 2000. Table 38 shows that federal revenues would again parallel state revenues closely after the initial few years.

The results for the high price scenario are summarized in Table 39, as derived from individual field results displayed in Appendix G, Tables G.2 and G.7. In the high case, all the fields are feasible except for Gwydyr Bay, which is nearly feasible. While it is possible that this smaller field could be developed in conjunction with adjacent, more profitable fields, costs are apparently too high for it to stand on its own under reasonable price projections.

Total North Slope production in the high case actually peaks at over 700 million barrels in 1993, and still exceeds 440 million barrels by 2000. Real state petroleum revenues peak at \$4.4 billion in 1987 (measured in 1984 dollars), but are still over \$3 billion in 1995 and nearly \$2 billion in 2000. Federal revenues in this scenario are slightly higher than state revenues except for the effect of income tax deductions for enormous development expenditures for West Sak heavy oil in the early 1990s.

TABLE 38
SUMMARY OF ALASKA NORTH SLOPE OIL
PRODUCTION AND REVENUES: LOW CASE

	TOTAL OIL PRODUCTION (MILLION BARRELS)	TOTAL STATE PETROLEUM REVENUES (MILLION 1984 \$)	TOTAL FEDERAL REVENUES (MILLION 1984 \$)*
1983	600.1	1662.0	162.3
1984	600.1	1634.7	652.3
1985	600.1	1615.2	911.4
1986	600.1	1599.3	870.7
1987	595.6	1613.1	1655.4
1988	525.8	1437.5	1471.8
1989	464.2	1276.2	1264.8
1990	409.8	1138.2	1096.8
1991	361.8	1000.7	949.7
1992	319.4	879.5	819.4
1993	282.0	773.0	707.7
1994	249.0	589.4	649.8
1995	219.8	512.9	563.3
1996	194.1	446.2	487.8
1997	171.3	387.1	420.1
1998	141.6	324.4	361.5
1999	124.9	281.2	312.3
2000	110.3	239.8	264.1
2001	97.3	210.2	231.3
2002	85.9	178.3	193.7
2003	75.8	150.5	160.3
2004	66.9	126.2	130.8
2005	59.0	105.1	104.5
2006	52.1	86.9	81.2
2007	46.0	71.3	60.5
2008	40.6	58.3	41.9
2009	35.8	47.7	25.1
2010	31.6	40.0	9.5

*Federal Windfall Profits Tax and Corporate
Income Tax

Source: FINDOIL Model Projections, Low Case

TABLE 39
SUMMARY OF ALASKA NORTH SLOPE OIL
PRODUCTION AND REVENUES: HIGH CASE

	TOTAL OIL PRODUCTION (MILLION BARRELS)	TOTAL STATE PETROLEUM REVENUES (MILLION 1984 \$)	TOTAL FEDERAL REVENUES (MILLION 1984 \$)*
1983	600.1	4057.9	4380.8
1984	600.1	4036.8	4703.7
1985	620.1	4118.8	4903.6
1986	645.7	4237.5	4771.2
1987	680.4	4441.5	5493.2
1988	658.8	4290.6	5299.7
1989	620.1	3960.5	4594.5
1990	605.1	3761.2	3420.8
1991	566.5	3448.1	1537.9
1992	636.9	3491.4	1134.9
1993	706.4	3640.8	3552.0
1994	656.0	3300.7	3281.4
1995	614.1	3155.0	3048.1
1996	573.5	2935.3	2864.1
1997	537.9	2657.7	2605.7
1998	502.3	2400.8	2451.3
1999	470.8	2178.5	2228.3
2000	441.9	1971.6	2015.5
2001	417.5	1812.5	1831.4
2002	395.8	1658.3	1660.0
2003	364.6	1488.1	1881.4
2004	336.2	1337.7	1666.8
2005	303.9	1185.5	1476.9
2006	281.0	1071.7	1307.5
2007	256.8	951.0	1133.8
2008	238.1	853.9	975.4
2009	220.9	768.2	828.8
2010	180.1	621.3	703.7

*Federal Windfall Profits Tax and Corporate
Income Tax

Source: FINDOIL Model Projections, High Case

Federal Price Policy Scenarios: Table 40 summarizes North Slope production and state and federal revenues for the export case. The individual field results used to derive this summary are shown in Tables G.3 and G.8 in Appendix G. Higher wellhead oil prices in this scenario permit development of the first stage of West Sak heavy oil and the Flaxman field. Total annual North Slope oil production does not fall to 200 million barrels until 2001. State revenues are 21 percent higher than the base case in 1990 and 34 percent higher in 2000. Federal revenues are also higher than the base case by a similar percentage.

Tables 41 and 42 show the summary of production and revenues for the high case and the export case with extension of the Windfall Profits Tax. The figures in Appendix G Tables G.9 and G.10 show that extension of the tax to 2010 and removing the Alaska exemptions would not change the economic feasibility of any proposed North Slope development project. Indeed, even with the high price scenario, only Prudhoe Bay feels the impact of the tax. This is because all other North Slope fields would be "newly discovered oil" under the tax. The "base price" for this type of oil increases by statute by 2 percent per year above inflation.⁸ Even with a \$7.50 increase in world oil prices, the North Slope price typically would not exceed the base price.

The impact of a hypothetically extended Windfall Profits Tax on federal revenues from the Prudhoe Bay field is significant, however. The tax would collect nearly \$500 million more from Prudhoe Bay in 1995 in the high case, and nearly \$300 million more in 2000. State revenues decline by \$20 to \$30 million annually due to lower income taxes. In the export case, federal revenues would increase by around \$170 million in 1995 and by nearly \$100 million in 2000 if the Windfall Profits Tax remained in its present form.

Tax Policy: Tables 43 and 44 show the summaries of Alaska North Slope oil production and revenues for the two scenarios associated with a federal limitation of state severance taxes to a maximum rate of 10 percent. Tables G.11 and G.12 show the cumulative production and discounted cash flows for the eight fields (Gwydyr Bay not shown). When the economic limit factor is eliminated, the Endicott field and the Milne Point field do not appear to be feasible, although they are feasible in the base case. Total state revenues in this case, from Table 43, are 18 percent lower than in the base case, despite the elimination of the economic limit factor reducing effective severance tax rates below nominal rates. This results in part, however, because production in this case is 92 percent of base case production in 1990 and 95 percent of base case production in 2000.

TABLE 40
SUMMARY OF ALASKA NORTH SLOPE OIL
PRODUCTION AND REVENUES: EXPORT CASE

	TOTAL OIL PRODUCTION (MILLION BARRELS)	TOTAL STATE PETROLEUM REVENUES (MILLION 1984 \$)	TOTAL FEDERAL REVENUES (MILLION 1984 \$)*
1983	600.1	3282.3	2573.8
1984	600.1	3261.2	2899.3
1985	620.1	3320.9	3063.3
1986	645.7	3409.8	2886.3
1987	680.4	3571.9	3559.7
1988	658.8	3448.9	3486.5
1989	620.1	3155.1	2934.1
1990	605.1	3014.1	3036.3
1991	566.5	2786.2	2696.9
1992	527.4	2589.3	2433.4
1993	484.9	2373.9	2295.9
1994	437.0	2112.4	2070.0
1995	395.1	1721.8	1943.0
1996	354.5	1508.8	1748.2
1997	318.9	1502.8	1447.1
1998	283.3	1307.3	1345.0
1999	250.4	1131.8	1172.6
2000	222.9	977.9	1001.7
2001	198.5	855.9	856.6
2002	176.8	736.8	718.9
2003	149.2	611.8	598.3
2004	133.1	524.4	496.4
2005	114.6	438.5	406.8
2006	102.3	373.5	328.3
2007	66.8	263.6	266.3
2008	51.7	198.7	219.8
2009	45.7	165.4	180.2
2010	40.3	139.0	143.8

*Federal Windfall Profits Tax and Corporate
Income Tax

Source: FINDOIL Model Projections, Export Case

TABLE 41
SUMMARY OF ALASKA NORTH SLOPE OIL
PRODUCTION AND REVENUES: HIGH CASE
WITH WINDFALL PROFITS TAX

	TOTAL OIL PRODUCTION (MILLION BARRELS)	TOTAL STATE PETROLEUM REVENUES (MILLION 1984 \$)	TOTAL FEDERAL REVENUES (MILLION 1984 \$)*
1983	600.1	4057.9	4380.8
1984	600.1	4036.8	4703.7
1985	620.1	4118.8	4903.6
1986	645.7	4237.5	4771.2
1987	680.4	4441.5	5493.2
1988	658.8	4290.6	5299.7
1989	620.1	3960.5	4594.5
1990	605.1	3761.2	3420.8
1991	566.5	3429.7	1810.9
1992	636.9	3458.9	1616.8
1993	706.4	3600.9	4142.7
1994	656.0	3265.5	3802.7
1995	614.1	3122.2	3533.5
1996	573.5	2906.3	3293.8
1997	537.9	2632.0	2986.3
1998	502.3	2378.0	2788.4
1999	470.8	2158.4	2527.0
2000	441.9	1953.1	2289.7
2001	417.5	1796.1	2073.7
2002	395.8	1643.8	1875.7
2003	364.6	1475.1	2073.5
2004	336.2	1326.2	1838.1
2005	303.9	1175.2	1629.7
2006	281.0	1062.6	1443.8
2007	256.8	942.8	1255.4
2008	238.1	846.6	1083.8
2009	220.9	761.7	925.4
2010	180.1	615.5	789.3

*Federal Windfall Profits Tax and Corporate Income Tax

Source: FINDOIL Model Projections, HIGHWPTX Case

TABLE 42
SUMMARY OF ALASKA NORTH SLOPE OIL
PRODUCTION AND REVENUES: EXPORT CASE
WITH WINDFALL PROFITS TAX

	TOTAL OIL PRODUCTION (MILLION BARRELS)	TOTAL STATE PETROLEUM REVENUES (MILLION 1984 \$)	TOTAL FEDERAL REVENUES (MILLION 1984 \$)*
1983	600.1	3282.3	2573.8
1984	600.1	3261.2	2899.3
1985	620.1	3320.9	3063.3
1986	645.7	3409.8	2886.3
1987	680.4	3571.9	3559.7
1988	658.8	3448.9	3486.5
1989	620.1	3155.1	2934.1
1990	605.1	3014.1	3036.3
1991	566.5	2779.7	2742.9
1992	527.4	2577.8	2402.9
1993	484.9	2359.9	2503.7
1994	437.0	2100.1	2253.3
1995	395.1	1710.3	2113.7
1996	354.5	1498.6	1899.3
1997	318.9	1493.8	1580.9
1998	283.3	1299.3	1463.5
1999	250.4	1124.7	1277.6
2000	222.9	971.4	1098.1
2001	198.5	850.2	941.8
2002	176.8	731.7	794.7
2003	149.2	607.2	665.9
2004	133.1	520.3	556.6
2005	114.6	434.9	460.5
2006	102.3	370.2	376.2
2007	66.8	260.8	309.1
2008	51.7	196.1	257.9
2009	45.7	163.2	214.1
2010	40.3	137.0	173.9

*Federal Windfall Profits Tax and Corporate Income Tax

Source: FINDOIL Model Projections, EXPWPTX Case

TABLE 43
SUMMARY OF ALASKA NORTH SLOPE OIL
PRODUCTION AND REVENUES: SEVERANCE TAX
LIMIT CASE

	TOTAL OIL PRODUCTION (MILLION BARRELS)	TOTAL STATE PETROLEUM REVENUES (MILLION 1984 \$)	TOTAL FEDERAL REVENUES (MILLION 1984 \$)*
1983	600.1	2489.2	1863.5
1984	600.1	2468.0	2199.2
1985	620.1	2519.4	2471.8
1986	640.2	2575.2	2406.7
1987	654.0	2616.3	3182.0
1988	616.8	2508.8	3212.4
1989	553.5	2258.1	2822.1
1990	493.1	2029.7	2505.9
1991	439.8	1814.5	2112.0
1992	408.2	1701.1	1867.1
1993	377.6	1591.9	1788.8
1994	336.9	1422.1	1565.6
1995	301.0	1275.1	1389.4
1996	265.5	1125.7	1248.4
1997	234.2	962.6	1091.1
1998	206.7	847.1	941.4
1999	182.3	844.5	773.7
2000	160.9	739.0	652.0
2001	141.9	647.1	557.1
2002	115.6	532.1	470.4
2003	102.0	464.7	394.2
2004	85.3	395.7	329.4
2005	75.3	344.6	273.2
2006	66.5	299.6	223.5
2007	53.9	250.8	182.1
2008	47.5	214.1	148.1
2009	41.9	184.8	116.6
2010	37.0	110.9	111.0

*Federal Windfall Profits Tax and Corporate
Income Tax

Source: FINDOIL Model Projections, SEVLIMIT Case

TABLE 44
SUMMARY OF ALASKA NORTH SLOPE OIL
PRODUCTION AND REVENUES: TAXSHIFT CASE

	TOTAL OIL PRODUCTION (MILLION BARRELS)	TOTAL STATE PETROLEUM REVENUES (MILLION 1984 \$)	TOTAL FEDERAL REVENUES (MILLION 1984 \$)*
1983	600.1	2798.7	1723.1
1984	600.1	2758.5	2052.1
1985	620.1	2787.3	2207.2
1986	645.7	2838.4	2018.6
1987	680.4	3009.0	2829.3
1988	658.8	2956.2	3060.4
1989	592.7	2675.7	2668.0
1990	535.7	2464.7	2392.8
1991	482.6	2227.4	2109.5
1992	446.6	2058.1	1876.8
1993	406.9	1885.7	1807.4
1994	361.5	1670.4	1599.4
1995	321.8	1391.1	1456.1
1996	283.2	1215.1	1304.4
1997	249.4	1053.3	1127.4
1998	217.7	1033.6	916.2
1999	192.1	898.8	798.9
2000	169.4	772.5	677.9
2001	149.4	670.6	579.7
2002	122.2	553.0	487.4
2003	107.9	472.9	411.0
2004	90.4	393.6	345.7
2005	79.8	333.9	288.8
2006	70.4	281.8	238.3
2007	53.9	215.7	198.2
2008	47.5	180.4	163.5
2009	41.9	150.2	132.5
2010	37.0	125.2	104.4

*Federal Windfall Profits Tax and Corporate
Income Tax

Source: FINDOIL Model Projections, TAXSHIFT Case

In the scenario in which the state leaves intact the structure of the severance tax but modifies the corporate income tax to recapture lost revenue from the severance tax limit, there is no change in projected production from the base case. Total state revenues in this case are only 1 percent lower than the base case projection in 1990, and are actually 6 percent higher in 2000. Clearly, reinstating the separate accounting method for assessing petroleum corporate income taxes, if a court decision favors its constitutionality, is a better option for protecting state revenue than changing the structure of the severance tax.

Alaska OCS Production and Revenues

In Chapter IV, we discussed the magnitude of potential undiscovered recoverable petroleum reserves which may ultimately be found on the Alaska federal Outer Continental Shelf. Although there have as yet been no commercial discoveries, most analysts believe that the huge areas of favorable geology will yield a number of giant fields. The economic feasibility of OCS discoveries, should they occur, has been the subject of considerable study. In addition to the more general research discussed in Chapter IV, the U.S. Department of the Interior, Minerals Management Service, has sponsored preparation of hypothetical petroleum development scenarios for each OCS management area.⁹

These scenarios, prepared to represent the likely pattern of development expenditures and production, given a hypothetical discovery, provide an opportunity to assess possible future petroleum production and revenues from the Alaska federal OCS. Since the petroleum development scenarios are conditional upon discovery of recoverable reserves of a given size, one should be careful not to interpret the scenario for each OCS area as a likely projection for that region. In many regions, oil will not be found during the next twenty years in commercially developable quantities.

It is not possible to determine at the present time what might be a likely outcome for OCS exploration in each management area. Using the probabilities published by MMS for the probability that oil is present in paying quantities in a geologic basin as a guide, one can say that the probability is greater than 50 percent that significant oil reserves will be found somewhere in the Bering Sea. In the Beaufort Sea, the probability is much greater than 50 percent.

We choose a benchmark scenario for Alaska OCS development, assuming development occurs in both the Beaufort and the Bering Seas. For Beaufort development, we assume development follows the pattern of the combined total of the mean cases for OCS Sale 71 and the 1984 Diapir offering. For the Bering Sea scenario, we assume production occurs at the mean case level only for the Navarin Basin, the most promising area in the region.¹⁰ This is a similar methodology to that used by the Minerals Management Service to assess the potential cumulative economic and demographic impacts of the OCS leasing program in Alaska.¹¹

We assume that any gas produced from Bering Sea or Beaufort Sea leases would not be feasible to sell under reasonable demand projections. For Beaufort gas, an export market opportunity depends upon the completion of a transportation system for North Slope gas. Even if such a system were in place, its high cost would leave almost no wellhead value for gas producers. A detailed feasibility study of hypothetical Bering Sea gas production concluded that world gas prices would be unlikely to support commercial production in that region.¹²

Table 45 projects oil production and oil royalty payments from the Alaska OCS for the scenario described above. Oil production begins in the Beaufort Sea region in 1992 and in the Bering Sea region four years later. Total production peaks at 427 million barrels in 2002, declining to under 200 million barrels annually by 2010. Cumulative production to 2010 is just over 6 billion barrels, of which three-quarters comes from the Beaufort Sea.

The projection for oil royalties in Table 45 assumes a constant real wellhead prices of \$25 per barrel for Bering Sea production and \$15 for Beaufort Sea production as well as an average royalty share of one-sixth. Total royalties average around \$1 billion per year, with a cumulative (undiscounted) total of nearly \$18 billion received between 1992 and 2010. Although the federal government will receive all the oil royalty payments from Alaska OCS production, the state may receive petroleum property taxes from onshore facilities related to offshore production. These payments may be as high as \$100 million per year (in 1984 dollars) during the 1990s for the scenario represented in Table 45.¹³

Summary and Discussion

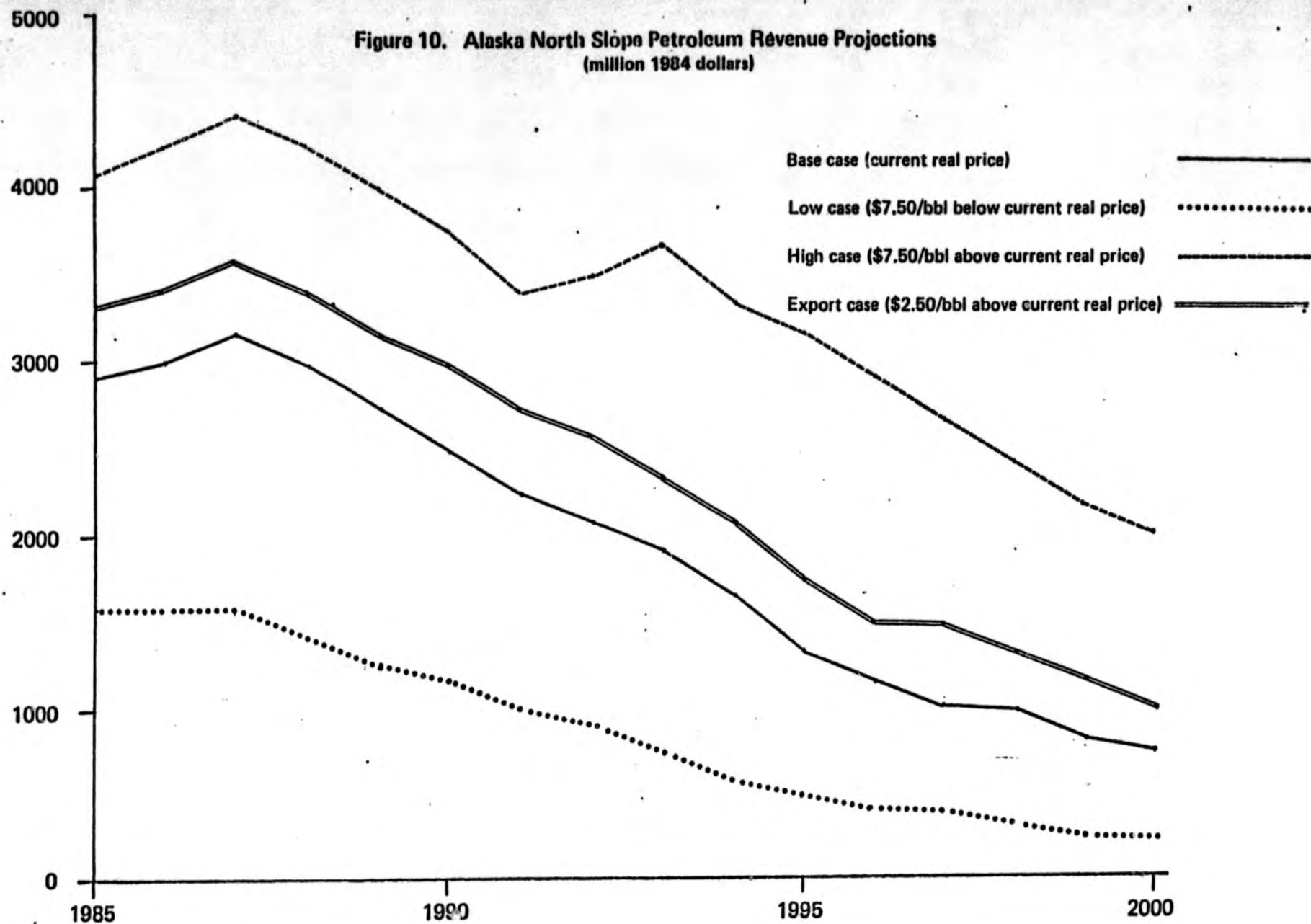
Figure 10 illustrates the projected sensitivity of Alaska North Slope petroleum revenues to changes in the wellhead price of oil. The revenue patterns include the effects of changes in the quantity of oil produced as a result of price differences as well as the effects of changes in unit wellhead values. The figure shows the difference from the base case (constant real wellhead price) for the high case (\$7.50 per barrel real price increase), the low case (\$7.50 per barrel real price decrease), and a \$2.50 increase per barrel, which might be the long run effect of lifting the export restrictions on North Slope oil. Figure 10 shows clearly the high degree of uncertainty for Alaska petroleum revenues associated with uncertainty about the level of wellhead prices.

TABLE 45
ALASKA FEDERAL OCS PROJECTED OIL PRODUCTION
AND ROYALTIES, 1991-2010

	OIL PRODUCTION (MILLION BARRELS)			TOTAL ROYALTIES (MILLIONS OF 1984 DOLLARS) (ASSUMING 1/6 ROYALTY)		
	BEAUFORT SEA	BERING SEA	TOTAL	BEAUFORT SEA	BERING SEA	TOTAL
1991 AND PRIOR YEARS	0	0	0	0	0	0
1992	126	0	126	315	0	315
1993	320	0	320	800	0	800
1994	424	0	424	1,060	0	1,060
1995	400	9	409	1,000	38	1,038
1996	293	26	319	733	108	841
1997	226	53	279	565	221	786
1998	244	88	332	610	367	977
1999	256	123	379	640	513	1,153
2000	255	149	404	638	621	1,259
2001	255	166	421	638	692	1,330
2002	259	168	427	648	700	1,348
2003	259	155	414	648	646	1,294
2004	237	131	368	593	546	1,139
2005	215	111	326	538	463	1,001
2006	195	95	290	488	396	884
2007	176	80	256	440	333	773
2008	158	68	226	395	283	678
2009	141	49	190	353	204	557
2010	<u>127</u>	<u>49</u>	<u>176</u>	<u>318</u>	<u>204</u>	<u>522</u>
1990-2010	4,566	1,520	6,086	11,420	6,335	17,755

SOURCE: U.S. Department of Interior, Minerals Management Service

Figure 10. Alaska North Slope Petroleum Revenue Projections
(million 1984 dollars)



Source: Tables 37, 38, 39, 40.

X

We analyzed two possible state responses to a federally-imposed maximum severance tax rate of ten percent. One response would be for the state to modify the rate structure so as to eliminate the economic limit factor (ELF), thereby attempting to lessen the impact on total severance tax collections. The other would be to reinstate the separate accounting method for the petroleum corporate income tax, assuming its constitutionality is upheld. Figure 11 shows revenue effects of the two responses to a severance tax limit initiative as compared to the current Alaska state revenue structure. The case eliminating the ELF performs poorly, in part because higher effective rates for non-Prudhoe production render some marginal production uneconomic.¹⁴

The results of the cumulative present values of oil development shown in Table 35 suggest a related observation about the structure of Alaska petroleum revenues. We have noted that known deposits of heavy oil on the North Slope near the Kuparuk field contain possibly over 40 billion barrels of oil in place. None of this oil is produced commercially at the present time, and any such development would clearly be only marginally profitable under reasonable price projections.

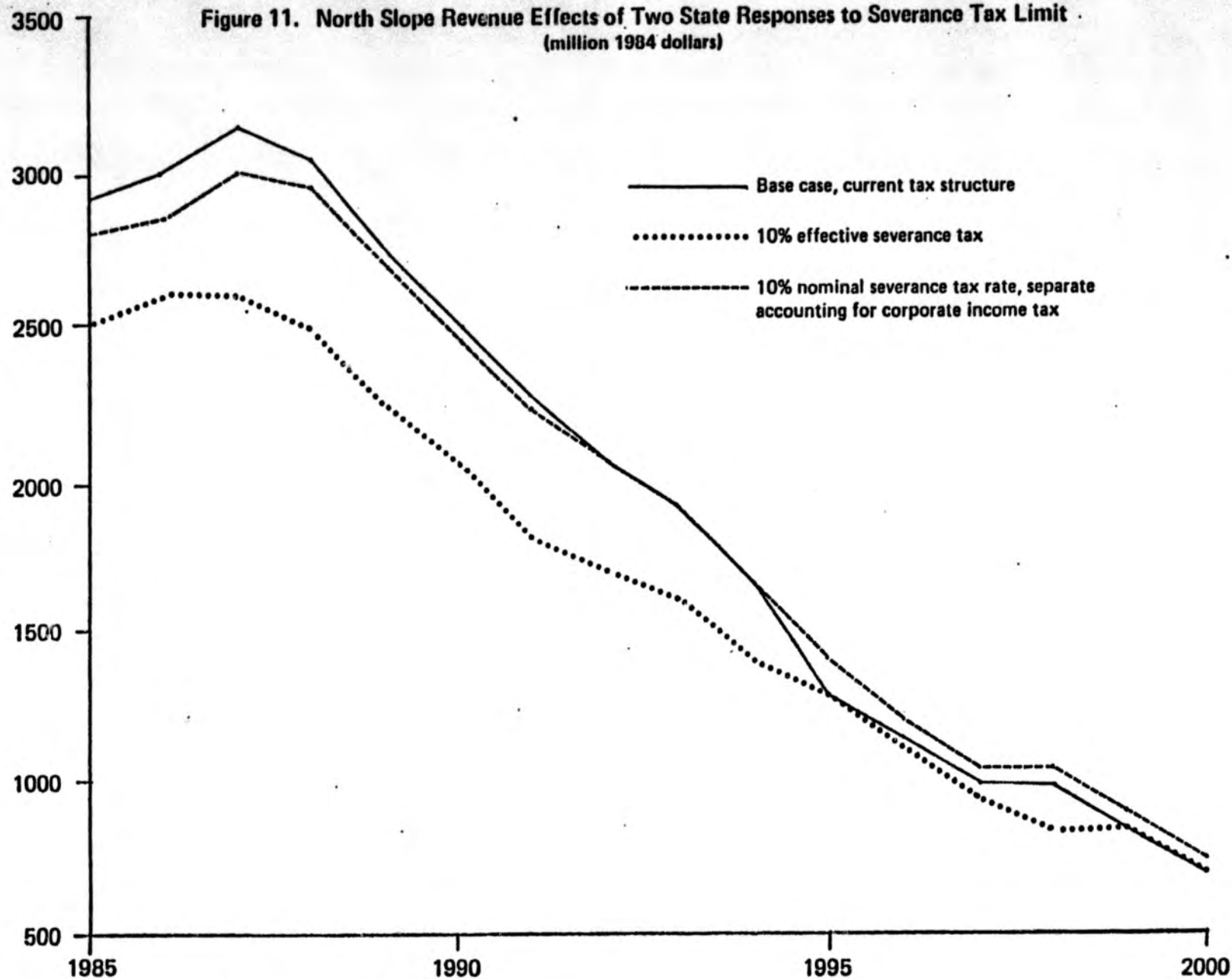
For the first stage of the hypothetical West Sak heavy oil development summarized in Table 35, the present value of profits is negative, showing the lack of feasibility under the base case assumptions. However, the present value of all excise taxes and royalties (that is, the value of the stream of cash flows as valued by the operators) is more than four times larger than the negative profits. Due to the low ELF derived from low average production per well of heavy oil, severance tax projections for this hypothetical development are very small. Under the development assumptions used for this field, the state's royalty share makes the difference between feasibility and infeasibility.

The same problem may occur on other potential marginal fields on the North Slope. Of course, it would be financially irresponsible for the state to reduce the royalty share on speculation of effects on feasibility. However, the state might consider ways to credit capital costs of developing new North Slope heavy oil fields against the first royalty payments owed when production begins. The royalty credit could be converted into a modified net profit share by having the credit repaid with shares of lease income at a rate of, say, 30 percent. Such a program could provide a large gain in revenue to the state if it successfully stimulates production from new fields.

★

In all the scenarios we examined in this chapter, North Slope oil production declined steadily in the 1990s despite the addition of a number of large new fields. This mainly results from the huge size of current production from Prudhoe Bay, but also because new production added over the next eight years will also be declining in the 1990s. Commercial production from the federal OCS may make a significant contribution to filling the gap.

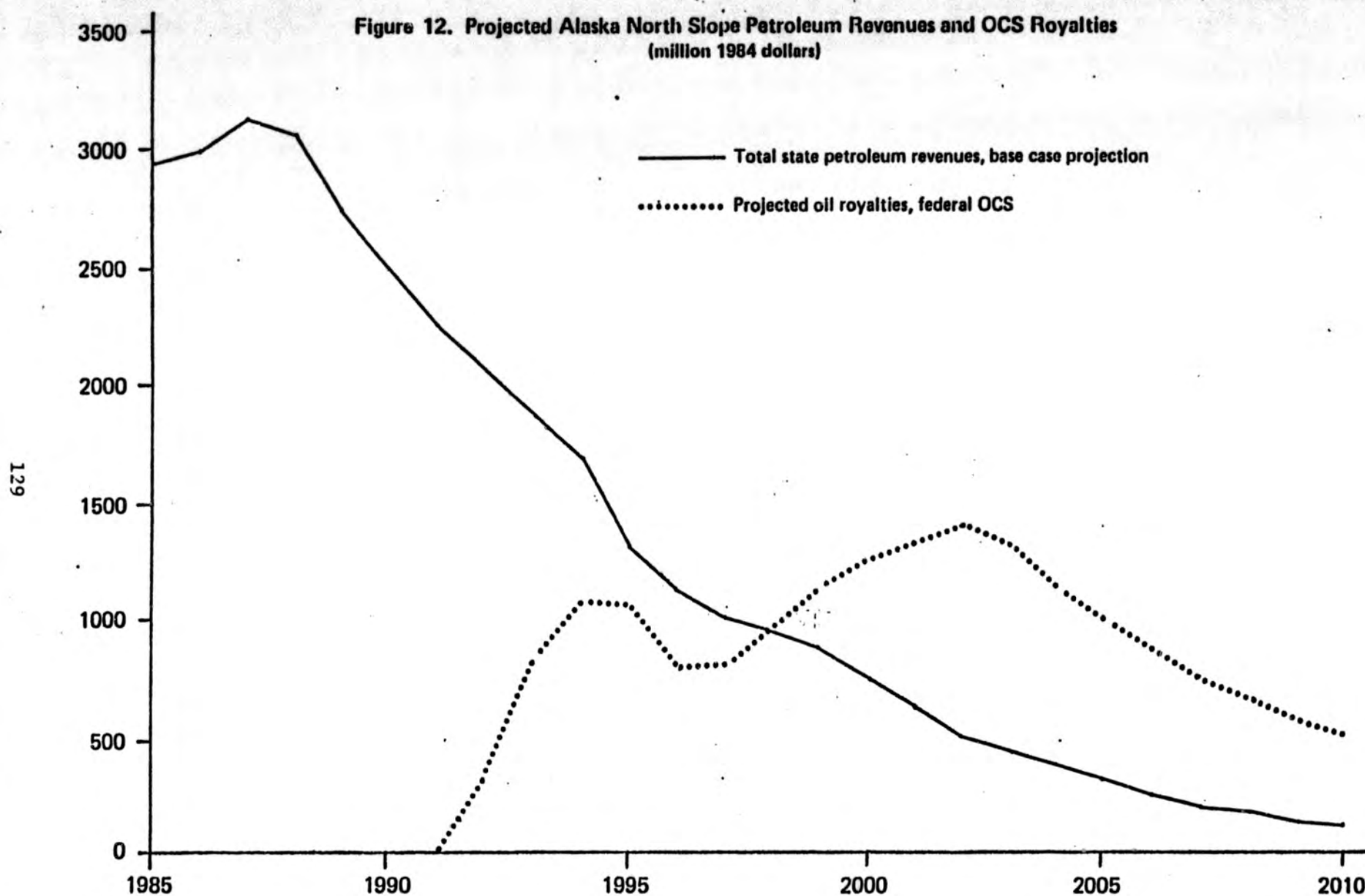
Figure 11. North Slope Revenue Effects of Two State Responses to Sovereignty Tax Limit
(million 1984 dollars)



Source: Tables 37, 43, 44.

Figure 12 illustrates a plausible scenario for oil royalty payments received from federal OCS leases, compared to the base case pattern projected for North Slope state petroleum revenues. At present, states do not receive a share of OCS royalties, and current congressional proposals for sharing OCS lease payments with coastal states would yield the State of Alaska only a tiny fraction of the amount shown in Figure 12. The next chapter discusses the legislative background and policy issues for sharing OCS and other resource revenues from federal lands with the states.

Figure 12. Projected Alaska North Slope Petroleum Revenues and OCS Royalties
(million 1984 dollars)



Source: Tables 37, 45.

ENDNOTES

¹Alaska Department of Revenue projections assume an average production decline rate of 12 percent per year. Total oil and gas royalties and severance tax collections would decline to 2 percent of total state royalty and severance taxes by 1990. See Petroleum Production Revenue Forecast, quarterly report, March 1984, Alaska Department of Revenue, Petroleum Revenue Division, p. 16, 18.

²See Marketability of Bering Sea Natural Gas, Dames and Moore, U. S. Department of the Interior, Minerals Management Service, Alaska Outer Continental Shelf Region, Social and Economic Studies Program, Technical Report Number 86, April 1983.

³Atlantic Richfield Company, as reported in Oil and Gas Journal, June 25, 1984, p. 56, and Arlon Tussing, personal communication, May 20, 1984.

⁴See Oil and Gas Journal, July 2, 1984, p. 27.

⁵A detailed analysis of a number of scenarios for the potential effects of lifting the export ban on the price received for North Slope oil is contained in "The Export of Oil to Japan--State Revenue Impacts," in Alaska Department of Revenue, Division of Petroleum Revenue, Petroleum Production and Revenue Forecast, quarterly report, March 1983, 17-24. Another way of looking at the export scenario is that it might represent the effects on North Slope wellhead prices of a favorable ruling for the state in the TAPS tariff case.

⁶James Love, "Evaluation of Proposed Federal Energy Taxes," Alaska Department of Revenue, July 7, 1982, discussed several alternative proposed national energy taxes and their hypothetical impacts on the state of Alaska. Love also illustrated the minimal impact of the federal Windfall Profits Tax on North Slope oil under prevailing market prices, even if the exemption were removed for non-Prudhoe oil.

⁷See discussion of the rate structure for the Alaska severance tax in Chapter II.

⁸Detailed structure of federal Windfall Profits Tax is discussed in Appendix D.

⁹These studies include Beaufort Sea Region Petroleum Development Scenarios, Technical Report No. 6, April 1978; Northern Gulf of Alaska Petroleum Development Scenarios, Technical Report No. 29, March 1979; Western Gulf of Alaska Petroleum Development Scenarios, Technical Report No. 35, March 1979; Lower Cook Inlet and Shelikof Strait Petroleum Development Scenarios, Technical Report No. 43, July 1979, Bering-Norton Petroleum Development Scenarios,

Technical Report No. 49, January 1980; and Bering Sea Cumulative Economic OCS Petroleum Development, Technical Report No. 80, August 1982. All published by the U.S. Department of the Interior, Minerals Management Service, Alaska OCS Region, Social and Economic Studies Program.

¹⁰Our sources for the scenarios are contained in Diapir Field Final Environmental Impact Statement (Sale 71), U.S. Department of the Interior, Minerals Management Service, May 1982, Table II.B.1.a; Diapir Field Lease Offering (June 1984) Final Environmental Impact Statement, U.S. Department of the Interior, Minerals Management Service, Table II-2; and Bering Sea Cumulative Economic OCS Petroleum Development, U.S. Department of the Interior, Minerals Management Service, August 1982, Table II.7.

¹¹Alaska Statewide and Regional Demographic and Economic Systems: Effects of OCS Exploration and Development, U.S. Department of the Interior, Minerals Management Service, Alaska OCS Region, Social and Economic Studies Program, Technical Report No. 106, April 1984. The economic and demographic projections in the report were based on a scenario for OCS petroleum development supplied by the Minerals Management Service.

¹²Marketability of Bering Sea Natural Gas, U.S. Department of the Interior, Minerals Management Service, Alaska OCS Region, Social and Economic Studies Program Technical Report No. 86, April 1983.

¹³See Alaska Statewide and Regional Demographic and Economic Systems: Effects of OCS Exploration and Development, op. cit.

¹⁴This is another example of the effect, noted in Chapter IV, of higher excise shares on the margin of development. Without the ELF, the effective excise share is higher, raising minimum economic field sizes above the size of some known North Slope fields.

CHAPTER VI

SHARING REVENUES FROM FEDERAL LANDS

Introduction

This chapter examines current proposals in Congress to share federal Outer Continental Shelf (OCS) revenues with the states. The approach of the chapter is to place the OCS revenue-sharing debate in the context of similar debates which have taken place during the past 80 years over management and distribution of the federal lands and their resource wealth.

At first glance, the legislative history of sharing revenues from the federal lands appears to be almost a random series of events, each successive law an ad hoc compromise reflecting the interests and political power of the moment of the forces brought to bear on the issue. The analysis of the chapter shows that this is not so, however. One can discern a consistent pattern in the way Congress has responded in the past to similar types of national objectives and local needs. In fact, variations observed in the pattern of federal programs are relatively minor, accounting for special problems with a particular type of federal land or for special needs of a particular local jurisdiction.

The following sections discuss the legislative history of programs sharing revenues from onshore federal lands with state and local governments. Next we discuss the same set of issues as they have arisen in relation to the OCS. In this way, one may compare recent proposals in Congress to share OCS revenues to the precedents established for the other federal lands. The proposed legislation Congress is currently considering appears inconsistent both in scope and in magnitude with nearly a century of precedents of federal policy toward management of the public lands.

The Issues in Revenue Sharing

National plans to increase oil and gas production on the Outer Continental Shelf (OCS) have been provoking conflict between coastal states and the federal government for the last decade. Alaska plays a large part in this conflict because the submerged lands off its coast are considered among the most promising for oil and gas discoveries. Of total undiscovered recoverable oil and gas expected from the OCS, 58 percent of oil and 41 percent of gas may lie off Alaska.¹

Coastal states and the federal government have different perspectives of how, where, and when OCS development should occur. In the national perspective, the energy issue revolves around concerns for national security, national economic vitality, foreign

relations, and international balance of payments. States, on the other hand, are concerned primarily with the environmental, economic, and social effects of OCS development on the adjacent coastal zone.

Coastal communities affected by OCS development may be hard pressed to finance the additional support facilities and services required by rapid population increases. These include, among others, schools, health care facilities, police and fire protection, water supply and sewage treatment systems, and housing. Incompatible resource uses may give rise to conflicts among demands created by residential, commercial, industrial, recreational, and subsistence activities. Environmental problems will also occur with the construction of shore-based petroleum facilities. Petroleum processing facilities require large amounts of land and may cause air, water, noise, and visual pollution. The potential for large-scale oil pollution of coastal waters is an ever-present risk.

The costs OCS development often may impose on coastal states and communities follow the pattern of impacts on communities from mineral development and other activities on federal lands. Frequently a period of rapid growth during the construction phase of development is followed by an economic contraction. The most recent example of the boom-bust pattern is the situation in Wyoming and western Colorado in the wake of anticipated oil shale and coal development. In the light of this type of experience, it is hardly surprising that coastal states complain that they are being asked to carry an inordinate share of the risks and costs of OCS development. As long as twelve years ago, Congressional inquiries determined that "rapidly intensifying use of coastal areas already has outrun the capabilities of local governments to plan their orderly development and to resolve conflicts."²

For nearly eighty years, Congress has attempted to compensate states and communities for the presence of and activities occurring on federal onshore lands. In spite of coastal state pressure for similar compensation for OCS development, Congress has to date provided only for a relatively inconsequential program of grants and loans to affected coastal states and communities. Supporters of expanded OCS revenue sharing argue that coastal communities should not have to bear unaided the negative impacts of energy development benefitting the entire nation, that available impact funding is insufficient to compensate for impact costs, and that OCS revenues should be shared in a manner consistent with long-established practice for other federal lands. Opponents argue that OCS development impacts are, in fact, minor in most areas, that coastal states and communities are adequately compensated for impacts through the existing federal assistance program and through taxation of shore-based facilities, and that all OCS revenues should be used to benefit the entire nation.

It is helpful in understanding the current debate about OCS revenue sharing to place it in its historical context. The next section contains an analytical legislative history of the major federal programs sharing revenues from federal lands with the states and their local governments. The analysis does not include an examination of the merits of alternative initiatives for sharing a portion of OCS revenues with coastal states recently discussed in Congress. Rather, the focus is on clarifying the cumulative direction of existing federal-state resource revenue sharing programs, emphasizing the precedents established which may be appropriate for reference to the OCS revenue sharing issue.

U.S. public land policy, until the end of the 19th Century, emphasized transferring lands from federal to private ownership. This policy was consistent with the prevailing philosophy that the federal government should play only a small role in economic affairs, and land sales were a convenient means of raising needed revenues. Scant attention was paid to the fiscal impact of federally owned lands on state and local governments as long as the expectation existed that these lands would be transmitted to private hands sooner or later. The fact that the public lands were largely uninhabited and produced little resource revenue reinforced this lack of attention.

This policy gradually reversed, however, over a period of twenty years, beginning in 1891. In that year, Congress established a system for reserving for permanent federal ownership land in the public domain. The 1910 Pickett Act enabled the President to withdraw lands from availability for sale or settlement, and the 1911 Weeks Act reversed the policy of disposal by authorizing the acquisition of land by the federal government.

The withdrawal and reservation of large tracts of forested lands that began in the 1890s first put the new policy into action. In the process, a debate began about the political and fiscal equity implications for subnational governments of permanent federal land ownership and control. A principal issue for state and local governments is the loss of control over a large portion of land and resources within or adjacent to their boundaries and affecting the welfare of their population. Another argument raised by subnational governments concerns the tax-immune status of federal land.³ The property tax is the single most important source of revenue for state and local governments, the latter of which are especially limited in the means they have of raising funds to support the various public goods and services they provide.

Congress has over the years accepted some of the arguments raised by state and local governments by adopting a number of statutes sharing the revenues received from resource development on federal lands. These statutes may be classified broadly into three types. One type of revenue sharing program addresses the political

equity concern arising from the retention by the federal government of a permanent proprietary interest in the public domain. As a political settlement for appeasing state objections to federal control of resources and their development, Congress has enacted a number of programs designed to share with the state and local governments the value accruing to the federal landlord from resource development of the public domain.

The second type of revenue sharing program addresses the political compromise with state and local governments needed to allow the federal government to purchase and retain large amounts of private land for the purpose of federally-managed resource development or conservation. The third type of program attempts to replace the actual or potential reduction in local property tax revenues resulting from tax immunity of federal lands. This category includes tax equivalency payments or payments in lieu of taxes, and certain impact assistance programs. Table 46 provides a summary of the three types of revenue sharing programs, showing the national objectives addressed by the program, the normal basis for computing the payments the federal government shares with state and local governments, and whether the shared payment schedule normally includes a floor or a ceiling level.

Under the public domain and acquired lands revenue sharing programs, subnational governments receive a portion of the revenues generated from resource development or public use of federal lands within their boundaries. This approach suggests a partnership between the levels of government; the federal government manages the lands, sharing with state and local governments any revenues that may be produced on the lands. Payment in lieu of taxes programs, on the other hand, share with local governments the amount related to the local property taxes the federal government might pay if it were a private landowner. In practice, a few payments in lieu of taxes closely approximate full tax equivalency, and a few provide for partial tax equivalency, set at some percentage of tax value. Most, however, tend to be arbitrary, flat-sum payments.

Impact assistance programs are a special case of payments in lieu of taxes intended to offset the costs imposed by specific largely tax-exempt federal activities on local governments. They frequently include a negotiated payment, which usually does not attempt to reimburse localities fully for the community services used. Our concern here is primarily with payments in lieu of taxes on development of federal lands and resources. We are not concerned, therefore, with general revenue sharing nor with most impact assistance programs.

TABLE 46.
SHARING FEDERAL REVENUES TO OBTAIN LOCAL
SUPPORT FOR NATIONAL PROGRAMS HAVING LOCAL IMPACTS

	<u>Type of Program</u>		
	Resource Revenues from the Federal Public Domain	Resource Revenues from Federal Acquired Lands	Payments in Lieu of Taxes
National Objective Addressed	Increase federal land management intensity and control of resource development	Allow major federal purchases of private lands for development or conservation	Achieve property tax equity, allow major federal pur- chases of private land for conserva- tion or preservation
Recipients	States ^a	States or counties	Usually counties
Normal basis for payments	Fixed share of gross receipts from resource development	Fixed share of gross receipts from resource development	Flat or negotiated fee or percent of assessed land value
Floor level for payments	None	May have a PILOT floor	Often minimum per acre payment
Ceiling level for payments	None	None	May have a resource revenue or per capita ceiling

^aMay carry legislative restriction to distribute revenues to counties or spend on schools and roads.

Sharing Property Values of Federal Lands

This section summarizes the legislative history of programs sharing with state and local governments revenues received by the federal government from its proprietary interest in the natural resources on public lands. We note the few instances where practices regarding public lands in Alaska differ from those followed for other states. Table 47 summarizes the resource revenue sharing laws with which we are concerned, separating the programs into two categories, public domain and acquired lands, as described in Table 46.

Resource Revenues from the Federal Public Domain

At the end of the Revolutionary War, most of the land east of the Mississippi River was claimed by seven of the thirteen original states. The ownership of some of this land was, however, a subject of controversy due to the vague and contradictory language of the original grants to the colonies and a multitude of private land claims. The six states that did not have claims to western lands feared domination by the states that did and insisted that the lands should be common property of all the states that fought the Revolutionary War. For this and other reasons, the lands were ceded to the Confederation between 1781 and 1802. The difficulty of settling the conflicting ownership claims doubtless assisted in bringing about their cession to the national government. Thus originated the public domain, the lands owned by the federal government.⁴

Sale of Public Lands--Statehood Acts. One purpose for the creation of the public domain was to enable the central government to retire the public debt incurred in the Revolutionary War. Land was almost immediately offered for sale, a policy supported by holders of two viewpoints that were to be at odds over federal land policy for decades. One view considered public lands chiefly a revenue source for the new nation and held that land disposal receipts should be used to support the national currency.⁵ Holders of this view tended to advocate for price levels high enough to raise the sums required.

The other viewpoint considered public land chiefly as a place for settlement by people who lacked capital. A major motive for emigration to the new country, in fact, was to escape from traditional European systems of land tenure that prevented most common people from owning land.⁶ This group was interested in land being sold at terms favorable to the settlers, not for the benefit of the federal treasury.

TABLE 47. Provisions for Sharing Property Values of Federal Lands

Statute	Year Enacted	Type of Land or Program	State/Local Share	Payment Recipient	Use Restrictions	Administering Agency
Public Domain Lands						
Statehood Enabling Acts	1802-1958	Public domain	Usually 5% of net proceeds from sale of lands	States	Usually schools and roads	Dept. of Interior (BLM, Bureau of Reclamation)
National Forest Revenue Act	1908	Public domain and acquired lands in national forests	25% of gross receipts	States, must distribute to counties containing lands	Roads and schools in counties containing national forest lands	Dept. of Agriculture (Forest Service)
Mineral Leasing Act	1920	Public domain, with exceptions	50% (90% in Alaska)	States	Spending priority to areas affected by development	Dept. of Interior (BLM)
Federal Water Power Act	1920	Public domain and acquired lands used for specified water purposes	37.5% of net license receipts	States	None	Dept. of Treasury
Alaska Grazing Act	1927	Public domain in Alaska	All fee receipts exceeding costs of administration	State	Schools and roads	Dept. of Interior (BLM)
Taylor Grazing Act	1934	Unreserved and unappropriated public domain, except Alaska	12.5% of grazing fees from grazing districts	States	To benefit counties containing the land	Dept. of Interior (BLM)
			50% of fees from outside grazing districts		To benefit counties containing the land	
			33-1/3% from districts on ceded Indian lands		For schools and roads in counties containing the lands	
Migratory Bird Conservation Act	1935	Lands in National Wildlife Refuge System	25% of net receipts for public domain lands	Counties	Required to distribute to units of local government that experience tax losses	Dept. of Interior (U.S. Fish and Wildlife Service)

Table 47. (continued)

Statute	Year Enacted	Type of Land or Program	State/Local Share	Payment Recipient	Use Restrictions	Administering Agency
Sale of Materials from Public Lands	1947	Public domain and acquired lands administered by Depts. of Interior and Agriculture, with exceptions	For land administered by Interior usually 5% of net proceeds; in Alaska, 100% from proceeds from school section lands. For lands administered by Agriculture, varies by statute under which the land is administered.	States or counties	Varies	Dept. of Interior (BLM) and Dept. of Agriculture
National Petroleum Reserve, Alaska	1980	Lands within NPR-A	50% of oil and gas lease revenues	State of Alaska	Priority to spend in areas affected by oil and gas development on NPR-A	Dept. of Interior (BLM)
Acquired Lands						
Bankhead-Jones Farm Tenant Act	1937	Lands acquired under the Act's provisions	25% of net receipts	Counties	Schools and roads	Dept. of Interior (BLM) and Dept. of Agriculture (Forest Service)
Oregon and California Railroad Lands	1937	Reposessed O&C lands	50% of gross receipts	Counties	None	Dept. of Interior (BLM)
U.S. Corps of Engineers Flood Control Lands	1941	Land acquired by Corps for river and flood control	75% of lease receipts	States	Schools, roads and other purposes in counties containing leased lands	Corps. of Engineers
Mineral Leasing Act for Acquired Lands	1947	Acquired lands, with exceptions	Same as for other receipts from the lands (varies)	Varies by type of receipt or category of land	Varies by type of receipt or category of land	Dept. of Interior (BLM)

Despite some high hopes, land sales did not produce the level of revenues needed by the country when it was particularly hard-pressed financially. In general, federal land disposals were small, and most of the receipts were deposited in the general treasury instead of being used to pay off the European creditors who financed the Revolutionary War.

In 1802, with the admission of Ohio into the Union, Congress initiated the systematic distribution to new states of a share of the receipts from the sale of public lands. The precedent set with Ohio's admission was generally followed for other states: most receive 5 percent of the proceeds from the sale of public lands that lie within their boundaries. Congress usually stipulated that these funds must be used to build roads and support public education. The states, in turn, agreed not to tax federally owned lands, not to tax federal lands that were sold for five years, not to tax land given to soldiers who fought in the Revolutionary War (and other military bounty lands) for three years, not to interfere with public land sales, and not to discriminate against nonresident landowners.⁷ The distribution to the state of a share of proceeds from public land sales is a feature of agreements into which most states entered as a condition of statehood. The amount of revenue the states received from this source, however, has been quite small.

In 1824, when the national debt seemed to be nearly extinguished, Congress began to debate whether additional proceeds from land sales be distributed to all the states, an issue which would not be settled for seventeen years.⁸ Proponents of increased distribution argued that the federal government could afford it, that these constituted excess funds. Some states argued that all states, not only the newly admitted ones, had a right to a share of these revenues as compensation for their war losses and expenses. Supporters also maintained that distribution of the proceeds of sale would allow states to reduce taxes, build roads, and support public education. This would attract more settlers to western lands, which would be in the national interest. Increased distribution, they also claimed, would stimulate the economy by keeping in circulation funds which would otherwise be transferred from private hands to the federal treasury.⁹

Opponents of increased distribution insisted that it would weaken state governments and increase the power of the federal government. They argued in addition that distribution would discourage land sales and, therefore, westward expansion and settlement because states would have an interest in higher prices for land offered to settlers. Opponents also argued that land surveys would be delayed because land would be held in expectation of higher prices at a later date. Benefits would accrue to speculators, not to settlers.¹⁰ Distribution opponents often contended that the public lands rightfully belonged to the states in which they lay, and they wanted the lands given outright to the states.

Although the states were divided on the distribution question, those in favor outnumbered those against, and a shortlived distribution scheme was enacted in 1841. This program was suspended only a year later and was ultimately repealed due to unanticipated financial pressures on the federal treasury.¹¹

The Alaska Statehood Act followed the usual practice of assigning to the state 5 percent of net proceeds from the sale of public lands within its borders. The act stipulates that these funds must be used to support public schools.¹² Under temporary legislation enacted in 1964, Alaska for six years received an additional 85 percent of the proceeds from the sale of certain lands. The state was granted this additional revenue to offset potential losses it feared under temporary federal legislation for selling public lands that were adjacent to communities in certain western states and that were required for those communities' growth. Fearing that the federal government would sell lands that it might wish to choose in land selections granted in the Statehood Act, Alaska requested a 90 percent share of the proceeds from land sold under this legislation; in return, Alaska agreed to surrender its right to select equal acreage.¹³ Since the 1964 legislation lapsed in 1970, Alaska has received the standard 5 percent share of these proceeds.

Sale of Materials from Public Lands. During World War II, Congress temporarily authorized the Secretary of the Interior to sell certain raw materials from public lands administered by that department, including timber, forest products, sand, stone, gravel, clay, and certain plants. This law also provided that states were to receive the same portion of these receipts as from the sale of public lands, generally 5 percent. This law was made permanent in 1947¹⁴ and extended in 1955 to include sale of materials by the Secretary of Agriculture from lands administered by that department, in which case receipts are shared under provisions of any other laws applying to those lands.

This law applies to all public lands, both public domain and acquired, under the jurisdiction of the Interior and Agriculture Departments, except national parks and monuments, Indian lands, and lands held in trust for the Indians.

In 1950, all receipts from sales of materials on school section lands in Alaska were set apart in a separate fund in the Territorial treasury, to be used to support public schools.¹⁵

National Forest Revenue Act. The policy of disposal of public lands predominated through most of the nineteenth century, during which time concern grew that disposal practices were not working well. Those practices usually did not take into account the characteristics of the land to be sold, nor its suitability for various private uses. The assumed federal purpose was the wholesale

transfer of the lands from public to private hands, and to this end the laws were lenient. Even so, fraud and trespass were common, and lands were severely damaged through indiscriminate timber harvests, plowing, and intensive grazing.

Concern over this situation led to a significant change in federal policy, from one of disposal to one of retention in permanent federal ownership. In 1891, the federal government instituted the first system of land reservations under which public forest lands were permanently withdrawn from unlimited entry.¹⁶ From the beginning, private business interests and state governments in many western states vehemently opposed creation of these forest reserves, which were the beginning of the present National Forest system. The states' chief concerns were the potential restrictions and costs that might be imposed on their timber, mining, and livestock industries activities, and likelihood that withdrawn areas would never provide them any property tax revenues.

Responding to some of the concerns of the western states, Congress began to consider proposals for sharing national forest revenues with the states containing the national forest lands. Congressional supporters of sharing national forest revenues argued that states and counties containing these lands needed the additional revenues to afford even the most basic government services. Had the forest lands not been withdrawn from entry, they claimed, revenue-producing development would have placed them on the tax rolls. Supporters insisted that the federal government should reimburse the states and counties for their potential property tax losses as well as for the expenses of providing such public services on these lands as law enforcement and fire protection.¹⁷

Other members of Congress objected that national forest revenues belonged to and, therefore, should be used to benefit all U.S. citizens. They pointed out that the states and counties could not claim to have suffered a real tax loss since the forest lands had never been on the tax roll in the first place.

In 1906, Congress passed the National Forest Revenue Act, providing that 10 percent of the receipts from timber and forage sales from national forests be shared with the states containing the lands.¹⁸ The legislation required that states distribute the funds directly to the counties containing the national forest lands, and that the counties use the funds to build roads and schools.¹⁹ In 1908, the share received by states was increased to 25 percent, where it remains today. In effect, the system for sharing national forest resource revenues emerged as a compromise between conservation interests and interests in western states opposing the reservation of the public domain. By providing states with a share of the receipts from developing the property values of federal lands, Congress averted a drive to revoke various executive actions creating and adding to the national forests.²⁰