

Oil Taxes General

file 14

**ALASKA PETROLEUM REVENUES:
THE INFLUENCE OF FEDERAL POLICY**

Final Report

Prepared for

**State of Alaska
Office of the Governor**

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PREFACE

This report was the product of a joint research effort spanning approximately one year and involving a large number of participants. Although those preparing the report worked simultaneously on many portions of the research, primary responsibility of individual authors is as follows.

Eric Myers drafted the Alaska portion of Chapter II as well as Appendixes B and C. Will Nebesky prepared Appendixes D and E and supporting illustrations for Chapter III as well as edited the entire draft. Karen White prepared a draft of Chapter VI. Teresa Hull prepared the material for Appendix A. Matthew Perman supervised the research for the study, drafted the remainder of the text, including Appendixes F and G, and edited the final report.

The authors would gratefully like to acknowledge the contribution of a number of people. Without the assistance of these generous individuals, it would not have been possible to complete the study. Arlon Tussing initiated the project, providing ideas and information crucial to the progress of the study. Several public servants went far out of their way in order to provide us with needed information. Ed Park of the Division of Oil and Gas and Eric Hansen of the Division of Petroleum Revenue patiently handled numerous requests for data for the state of Alaska. George Clark, director of university lands accounting for the University of Texas System, and several staff members of the Energy Resources section of the General Land Office and the Revenue Estimating section of the Comptroller's Office provided invaluable assistance with data on Texas petroleum production and revenues.

We would also like to acknowledge the contribution of Professors Walter Mead of the University of California and Marlan Blissett of the University of Texas as well as the helpful suggestions of Dr. Charles Logsdon of the Alaska Department of Revenue and Mark Wittow of the Alaska Governor's Office. Lee Gorsuch provided helpful suggestions and encouragement. Cindy Tooke and Catherine Dwyer typed the draft. In fact, nearly the entire Institute staff assisted in one way or another in preparing the report. Final responsibility for errors and omissions, however, remains with the authors.

EXECUTIVE SUMMARY

This report examines the effects of certain federal policies on Alaska oil and gas revenues. Policies examined include price controls, federal excise taxes, limits to state severance taxes, the North Slope export ban, and OCS revenue sharing. Some of the major findings include:

- The federal government collected \$5.2 billion from the Alaska petroleum industry in 1982, mainly from the corporate income tax, Windfall Profits Tax, and payments for OCS leases.
- The federal government may receive over a billion dollars per year by the late 1990s in royalties from OCS oil production. Absence of a federal program sharing these lease revenues departs significantly from the pattern of historical precedents for sharing similar revenues from all other federal lands.
- Federal price controls on Cook Inlet oil cost the state of Alaska \$1 billion in revenues and oil producers \$1.3 billion in profits between 1974 and 1980.
- Lifting the Congressional ban on exporting oil transported through the trans-Alaska pipeline might yield one billion barrels in additional North Slope oil production and \$8.7 billion in state revenues by 2010.

The study focuses on the difference between the value of oil and gas at the wellhead and the cost of producing it, or the economic rent. An analysis of the size and distribution of petroleum economic rent over the past twenty years compares Alaska to Texas, the largest oil-producing state. General conclusions are:

- Federal policies such as wellhead price controls and the Windfall Profits Tax have been much more important than state tax policies in the division of economic rent between oil producers and governments.
- State, even federal, policies have had relatively little effect on shares of economic rent compared to the effects of world energy prices, the discovery of oil, landownership, and the cost of producing and transporting oil and gas to markets.

In addition to the general conclusions, specific findings from the economic analysis comparing the petroleum industry in Alaska to that in Texas include:

- The distribution of petroleum economic rent among taxes, lease payments to landowners, and oil company profits is roughly similar in the two states.
- Texas produces 50 percent more oil and 30 times more gas and collects 50 percent more severance tax revenues than Alaska. However, most Alaska oil production occurs on public lands, providing the state lease payments such as royalties which accrue in Texas mainly to private landowners.
- Although moderate excise tax and royalty rates have little effect on production in a lower-cost region such as Texas, they may increase minimum economic field sizes significantly and reduce exploration effort in high-cost, frontier areas of Alaska.

The report also examines the sensitivity of future Alaska oil production--and, ultimately, future petroleum revenues--to important market and policy factors. The study develops scenarios for probable oil production in the North Slope region, where most of Alaska's known oil reservoirs lie. Key findings of this analysis include:

- A number of large new fields are likely to be brought into production within the next decade on the North Slope, but Alaska onshore production, even including the contribution of these fields, is likely to decline 60-to-70 percent by the year 2000.
- The separate accounting method of corporate income taxation, if ruled legal by the courts, has less adverse impact--per dollar of revenue collected--on future North Slope oil production than severance taxes or other taxes on production.
- While federal and state governments are likely to collect around the same shares of economic rent from future onshore production, federal royalties from the Alaska OCS--none of which are currently shared with the state--may exceed total state petroleum revenues by the late 1990s.

Distribution of Economic Rent

The upheavals in world oil markets which have occurred over the past ten years have caused a huge increase in the potential or actual economic rents associated with energy production. Many recently prominent energy-resource issues are in one way or another related to the division of this economic rent among landowners, governments, and other parties. At both national and state levels,

energy policy has developed around the attempts of various interest groups to capture or allocate the "windfall" economic rent created by the rise in world oil prices.

Figure A shows the distribution of the total value of oil and gas production in Alaska in 1981, the peak year for energy prices. The cost of producing, developing, and exploring for oil and gas amounted to 20 percent of the total value of 14 billion dollars. This left over 11 billion dollars in economic rent, allocated in taxes to governments, in lease payments to landowners, and in profits to producers. Figure A shows that the federal government received 44 percent; the state government, 36 percent; and producers, 20 percent of the economic rent in 1981, with private landowners (Native regional corporations) receiving a minor share.

Figure B shows the same set of comparisons for oil and gas production in Alaska's Cook Inlet region in 1976, the only producing area of the state at that time. Federal wellhead price controls reduced the potential value of regional petroleum production by over 50 percent, as compared to market values for imported oil in 1976. In that year, producers received 39 percent of the remaining economic rent, a much larger share than in 1981.

In order to determine whether the historical pattern of economic rent and its distribution in Alaska is similar to that of other petroleum-producing states, the study developed a parallel analysis for Texas. Unlike Alaska, where nearly all oil and gas production occurs on public lands, approximately 90 percent of production in Texas occurs on lands owned by private corporations and individuals.

Figure C compares the value of oil and gas production in 1981 in Alaska and Texas, showing the shares of exploration and production costs and showing how lease payments, taxes, and profits allocate economic rent to landowners, governments, and producers. Total oil and gas production value was approximately three times as large in Texas as in Alaska in 1981. Although drilling and other petroleum industry costs are much lower in Texas, production is dominated by small, marginal fields. This industry structure results in a 44 percent share for costs in the total value, as opposed to just 20 percent in Alaska. In addition, lease payments such as royalties took a much larger share of the value in Texas, while profits and taxes took relatively smaller shares.¹

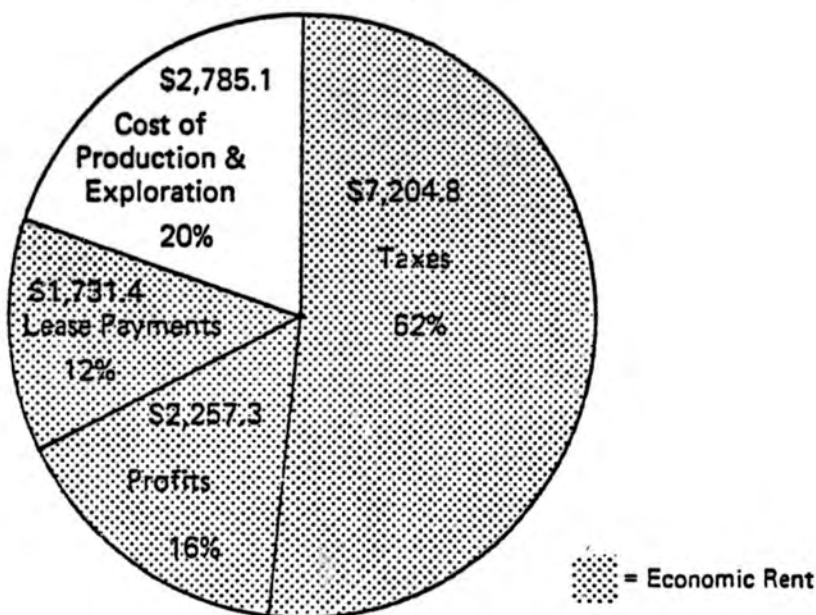
¹The tax category in Figures A, B, and C includes only those taxes paid by the petroleum industry which allocate a portion of the economic rent. Since all industries, not just the oil industry, pay property taxes (except on oil and gas reserves), general sales taxes, and payroll taxes, taxes such as these are included as part of the cost of production, rather than as part of economic rent.

Figure A

**Distribution of Total Value and Economic Rent
for Alaska Oil and Gas Production in 1981**
(millions of dollars)

Total Value of 1981 Production

\$13,978.6 million



Total Economic Rent in 1981

\$11,193.5 million

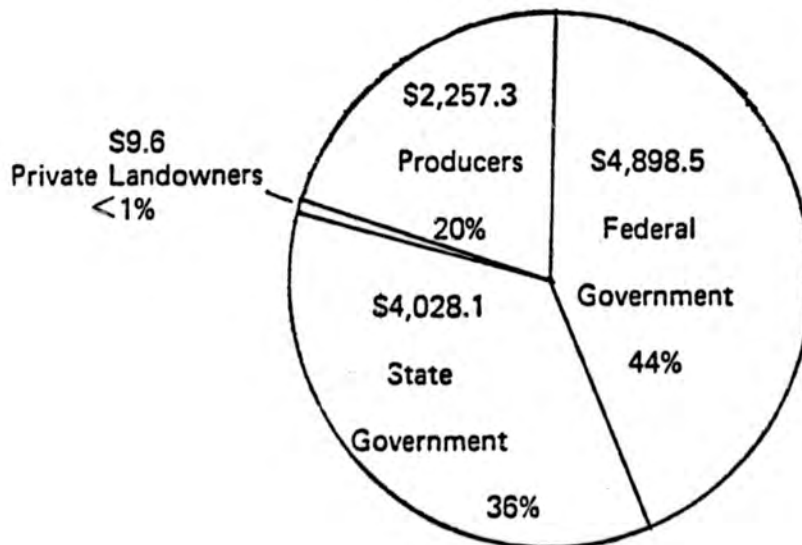
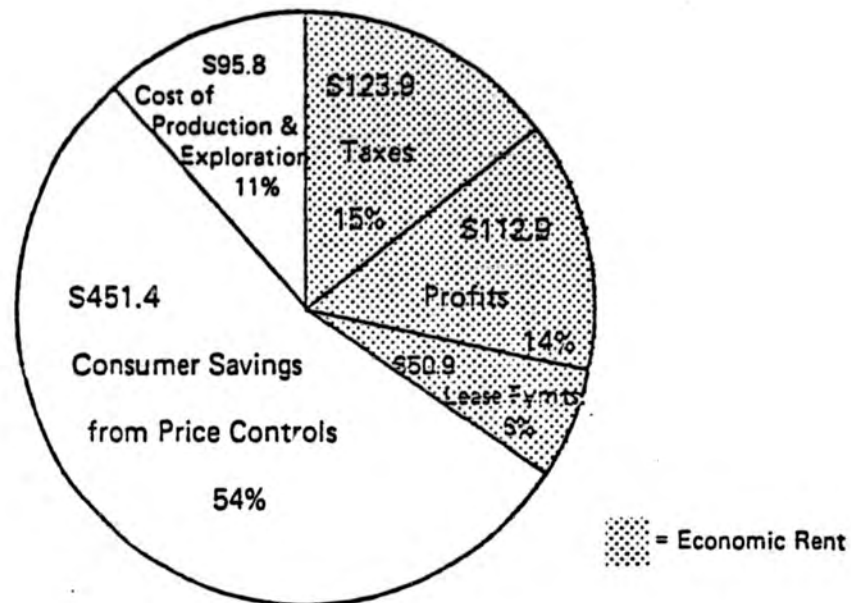


Figure B

Distribution of Total Value and Economic Rent
for Cook Inlet Oil and Gas Production in 1976
(millions of dollars)

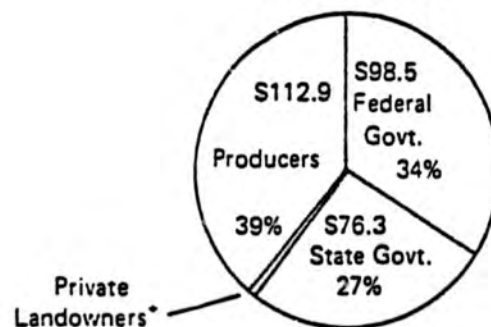
Total Value of 1976 Production

\$834.9 million



Total Economic Rent in 1976

\$287.7 million



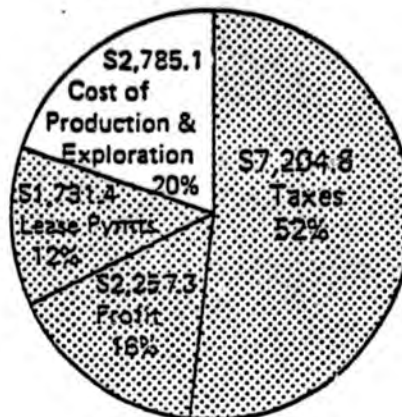
Note: *Negligible

Source: Figure 4.

Figure C
Distribution of Total Value of Oil and Gas Production
for Alaska and Texas in 1981
(millions of dollars)

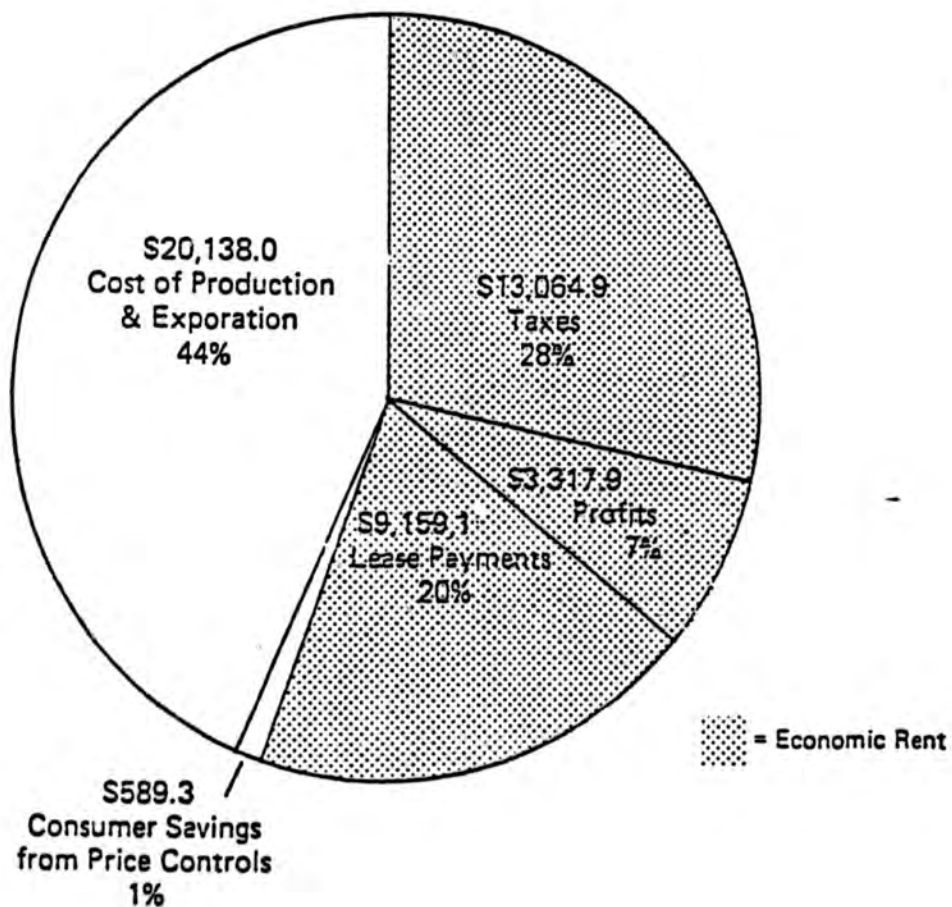
Alaska, All Regions

\$13,978.6 million



Texas Onshore & Offshore

\$46,269.2 million



When one considers the role of private landowners in Texas, however, the final division of economic rent among federal, state, and local governments, private landowners, and producers in 1981 is quite similar in Alaska and Texas. Figure D shows that private landowners in Texas, who own most of the oil and gas deposits in that state, received 21 percent of the economic rent--over 5 billion dollars (after taxes)--in 1981. Texas state government received 11 percent, mostly in severance taxes; and local governments, which tax oil and gas reserves, received another 7 percent. The state of Alaska receives lease payments for the oil and gas it owns, which are comparable to those which private landowners receive in Texas. The combined share of the petroleum economic rent received by state government and private landowners in Alaska was 37 percent in 1981, compared to the 39 percent combined share received by private landowners and state and local government in Texas.

The distribution of economic rent shown in Figure D is for 1981, the peak year for oil prices and economic rent. The study notes that in the period of stable oil prices from 1963-1971, landowners and governments in Texas received one hundred percent of the computed economic rents, leaving none to oil producers. Such was not the case in Alaska, however, with Cook Inlet producers consistently earning significant economic rents even with the low wellhead prices prevailing in the region.

The study goes beyond comparing the size and distribution of economic rent received from oil and gas development in the two states. It analyzes the contribution of various factors to the pattern observed in two major economic divisions of each state, noting that tax rates are only one of several important factors. The analysis shows that four factors are typically more important than state (and even federal) tax systems in determining the distribution of energy revenues among governments, producers, and consumers:

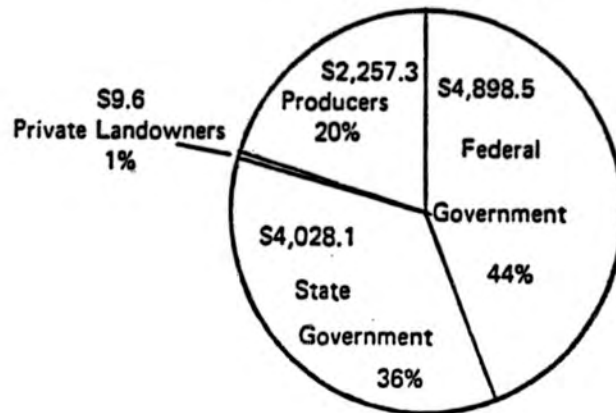
1. Geologic good fortune--the location of accumulations of oil and gas is randomly associated with state political boundaries. Oil companies have also spent billions of dollars over the past 20 years exploring for oil and gas in Alaska outside the producing Cook Inlet and North Slope regions, without a single commercial discovery to date.
2. Ownership of mineral rights--federal or state governments may retain title to subsurface estate, allowing them to receive proprietary lease payments such as royalties from oil and gas production. This is the principal factor explaining regional differences in the shares of economic rent received by federal and state governments and private landowners.

Figure D

**Distribution of Economic Rent from Oil and Gas Production
for Alaska and Texas in 1981**
(millions of dollars)

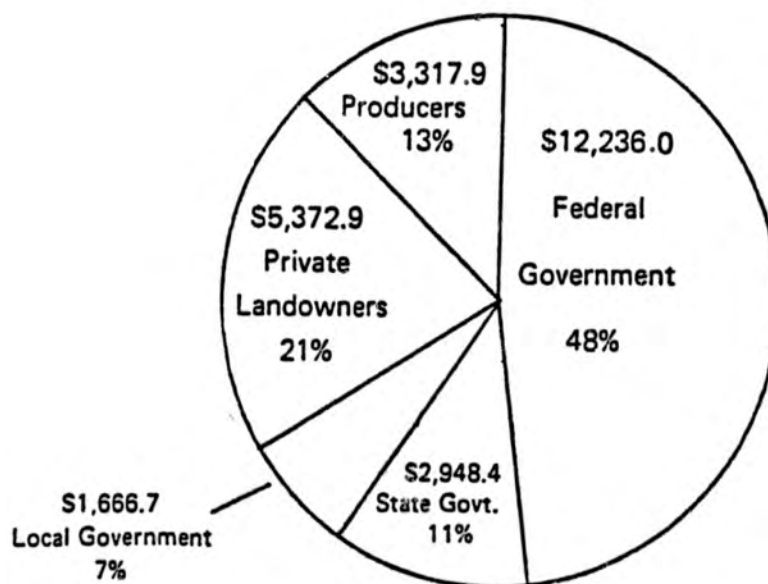
Alaska, All Regions

\$11,193.5 million



Texas Onshore and Offshore

\$25,541.9 million



Source: Figures 2 and 3.

3. Cost environment--exploring for and developing petroleum deposits in frontier regions such as Alaska is much more costly than in onshore areas in other states.
4. Market prices--individual states have little ability to influence markets for their energy products. In addition, federal wellhead price controls on oil and gas during the 1970s reduced total economic rent by around 20 percent in Texas and 40 percent in Alaska's Cook Inlet region.

The market price and cost factors have a severe combined effect on the size of petroleum economic rent in Alaska. If producers in the relatively low-cost Cook Inlet region had been able to benefit from the market prices and costs prevailing in Texas, economic rent would have more than doubled from the levels actually received between 1963 and 1982. On the North Slope, even giant fields such as the Kuparuk reservoir would not have been feasible to develop under oil price levels prevailing in the early 1970s. But, on the other hand, if a geologically similar field were found in Texas, it would have been a bonanza for producers (and governments) even at 1971 world oil price levels, due to Texas's lower development and transportation costs.

Effects of Prices and Policy on Production

Next, the study turns to the analysis of how various methods governments use to collect economic rent may reduce total economic rent, total petroleum production, and ultimately, total petroleum revenue. All methods of collecting economic rent--severance taxes, income taxes, royalties, etc.--affect investment decisions of oil producers to some extent, but some methods have more severe impacts than others.

Severance and other producer excise taxes (and royalties as well) can lead to earlier abandonment of producing fields. But the effect--typically just one more year of production--is relatively minor, adding only a percent or two to cumulative production from the field. This suggests that the Economic Limit Factor in Alaska's severance tax, which reduces the effective tax rate rapidly as production per well declines, has limited ability and high revenue cost for conserving oil and gas from producing fields.

Excise taxes and royalty shares are likely to have a greater impact on potential production from increasing minimum economic field sizes for discoveries in frontier areas. Under economic conditions such as currently prevail on Alaska's North Slope, adding a 30 percent share of combined royalty and severance taxes may cause a five-fold increase in minimum economic field size, from

100-300 million barrels to 0.5-1.5 billion barrels. The study examines recent geological studies to estimate that fields north of the Brooks Range, containing a total of 2-3 billion barrels of oil, may not be feasible to develop because of the combined effects of severance taxes and royalty shares. The study notes that governments should favor lease bonus payments, net profit shares, and income taxes--methods with little or no effect on minimum field sizes or on abandonment of producing fields--over royalty shares and excise taxes for collecting economic rent in frontier areas.

The study then develops a series of scenarios projecting the sensitivity of Alaska petroleum production and revenues over the next two-to-three decades to assumptions about market prices and policy factors. These projections examine feasible production from nine known fields located in the North Slope region, considering multiple development options for four of the nine fields. In addition to the Prudhoe Bay and Kuparuk fields, four new fields--including Milne Point, Endicott River, Lisburne, and Seal Island--appear to be feasible under current economic and policy conditions prevailing on the North Slope. These six fields form a "basecase" projection, producing approximately nine billion barrels between 1983 and 2010.²

Other fields, most importantly, West Sak heavy oil deposits overlying the Kuparuk field, appear to require higher prices (or lower costs) than are currently available. Figure E shows the projected sensitivity of feasible North Slope production from these nine fields, assuming four different levels for the North Slope oil price (price of Prudhoe Bay oil at Pump Station 1 of the trans-Alaska pipeline). The figure shows that if producers anticipate long-run oil prices to fall by around \$7.50 per barrel from the 1984 level (a \$10 North Slope price roughly corresponds to a \$20 world price), cumulative oil recovery would be approximately 2 billion barrels less than in the basecase. If North Slope prices were to rise to \$25 per barrel (in 1984 dollars), or around the historical peak level world oil prices reached in 1981 (after adjusting for inflation), it might be feasible to produce as much as 14 billion barrels.

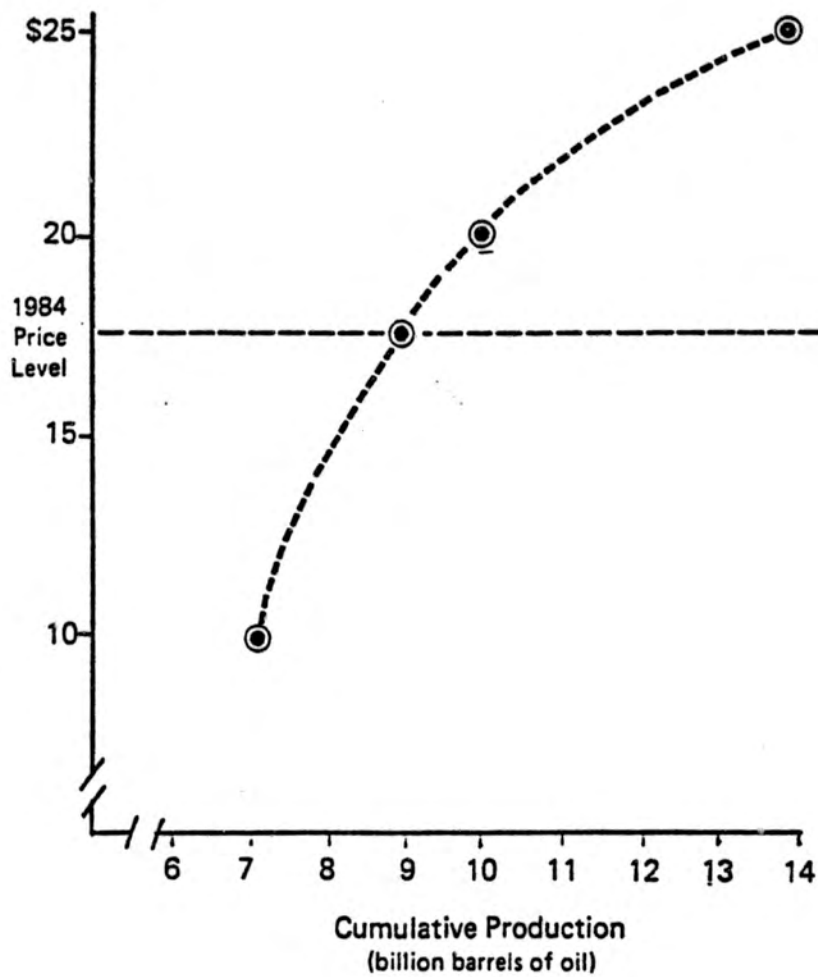
Although Figure E shows the relationship of North Slope petroleum supply to wellhead price, one may also interpret the curve as a potential response of cumulative oil production to policy initiatives which affect the feasibility of production in the same way as market prices. Federal policy measures such as the set of rules judged appropriate for setting pipeline tariffs, the ban on

²As of December 1982, cumulative production on the North Slope from the Prudhoe Bay and Kuparuk fields, according to the Alaska Oil and Gas Conservation Commission, was 2.7 billion barrels.

Figure E

CUMULATIVE PROJECTED NORTH SLOPE OIL PRODUCTION, 1983-2010

Prudhoe Wellhead
Oil Price Level
(1984 \$/barrel)



Source: Tables 37 through 40.

export of oil moved through the trans-Alaska pipeline, and a proposed national severance tax affect oil producers in the same way as would changes in expected market price levels.

Even under the most optimistic scenario, projected North Slope production falls significantly from current levels by the late 1990s. State revenues fall even more rapidly than production, due mainly to lower effective severance tax rates for the more marginal fields--which assume a larger share of production in future years--as compared to Prudhoe Bay. Production from new fields that may be discovered on the federal OCS is likely to offset somewhat the decline in production expected from fields located onshore and on state offshore lands. However, the state of Alaska receives no direct revenues from OCS production under current federal policies.

Figure F shows the projection to 2000 of total state North Slope petroleum revenues under the basecase price assumptions, along with a scenario of royalties derived from U. S. Department of the Interior data, which may accrue to the federal government from production on the Alaska OCS. By the late 1990s federal royalties received from the Alaska OCS may well exceed total state petroleum revenues.

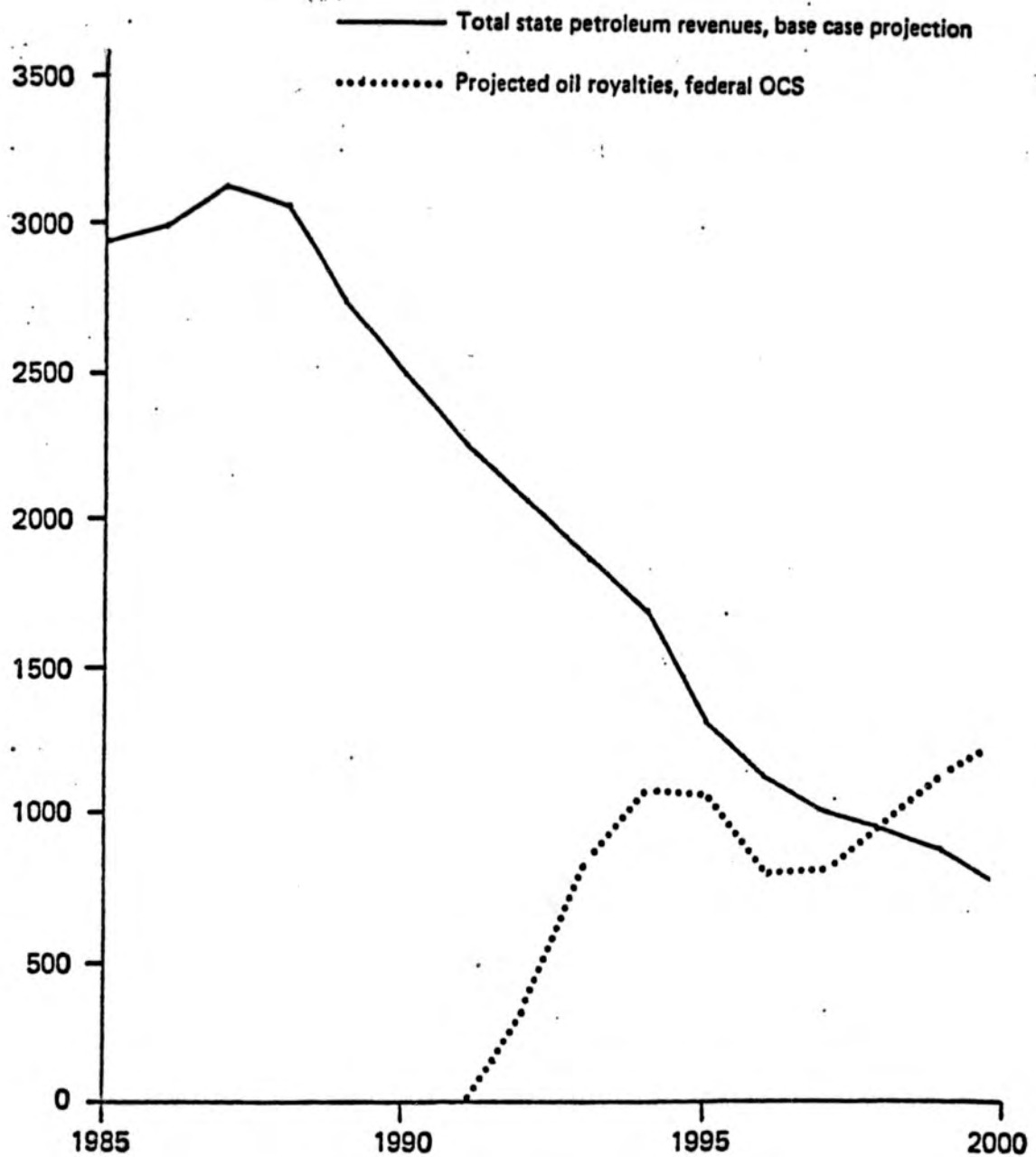
OCS Revenue-Sharing

The final section of the study examines recent efforts in Congress to share federal OCS revenues with the states, placing 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. The study analyzes the legislative history of sharing revenues from the federal lands, distinguishing three types of programs for balancing national objectives and local needs:

1. Resource revenues from the public domain, associated with major Congressional initiatives consolidating federal ownership and management of the public domain, share property values realized from resource development on these lands with the states. Examples include the National Forest Revenue Act (1908), the Mineral Leasing Act (1920), and the Taylor Grazing Act (1934).
2. Resource revenues from acquired lands, added to gain local acceptance of major federal land purchase programs, share revenues from resource development of federal acquired lands. Examples include the Bankhead-Jones Farm Tenant Act (1937) and the Mineral Leasing Act for Acquired Lands (1947).

Figure F

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



Source: Tables 37,45.

3. Payments in lieu of taxes programs allocate federal funds to local governments whose jurisdiction contains federal lands, compensating for the tax-exempt status of the federal lands and for federal decisions to withdraw some of these lands from development. Examples include the Payments in Lieu of Taxes Act (1976) and subsequent amendments.

These three types of programs have established a long series of precedents, continually broadened and strengthened throughout this century, for sharing resource revenues and user fees from federal lands with state and local governments affected by management of those lands. The federal government shares at least 25 percent of revenues from all the public lands, with the single exception of the OCS. In addition to these funds, the federal government distributes entitlement revenues under the Payments in Lieu of Taxes Act for lands which do not produce resource revenues or user fees.

The recent proposals (that died in the 98th Congress) for sharing OCS revenues are inconsistent both in scope and in magnitude with nearly a century of historical precedents of federal policy toward the public lands. The projection for OCS royalties shown in Figure F suggests that an OCS revenue-sharing program consistent with the other federal programs might yield Alaska \$200 million to \$500 million per year in the late 1990s.

CHAPTER I

INTRODUCTION

This report examines how federal oil and gas policies affect petroleum development and petroleum revenues in Alaska. We examine the dominant features which historically have affected both the amount and the pattern of public revenues collected and distributed. We use as a comparative benchmark the state of Texas, the largest oil-producing state, which differs significantly from Alaska in resource ownership and institutions. In addition, we assess the sensitivity of projected future production and total revenues to such factors as geologic and market risks, revenue collection methods and other public policies. The report also analyzes the possible effects of existing and proposed federal policies on Alaska's share (and by comparison other states' and the federal government's shares) of revenues derived from projected petroleum development.

Purpose for the Study

Interregional and state-federal conflicts over natural resource policy have long been high-profile issues in the western states. The "energy crises" of the 1970s raised several of these conflicts to nationwide status. Rising fuel prices, together with the continuing westward shift of population and industry, have recently led the national media and some public officials to pose these issues in terms of "equity" between the "energy-consuming" states of the Northeast and Midwest, and the "energy-producing" states of the West and Southwest.

In 1976, 213 elected representatives from eighteen northeastern and midwestern states formed a bipartisan political coalition to combat the economic decline of the region. Calling itself the Northeast-Midwest Congressional Coalition, the group advocated for federal legislation which would economically benefit the region. By 1980, it had begun to focus much of its attention on federal energy-related legislation, including promoting federal limits on state severance taxes, opposing decontrol of natural gas prices, and opposing the lifting of an export ban on Alaska oil.

Recent journalistic and political assaults upon the energy-exporting states have concentrated on limiting the authority of states to levy severance taxes on energy commodities. Severance taxes, however, are often only a minor part of the economic rent that is generated in the production of petroleum. It is the division of economic rent among the federal government, state and local governments, and private parties that is currently at issue.

Economic rent, simply defined, is the difference between the market value of a commodity and its resource cost, the value of capital, labor, and materials used in its production. Since it is not necessary to pay any of the economic rent to the suppliers of capital, labor, and materials in order to obtain their services, it is therefore a "windfall" revenue available for division among landowners, governments, and other parties having a nonproducing interest in the resource. Many of the prominent energy-resource issues are, at bottom, struggles over this division. Producer excise taxes (most importantly, state severance taxes and the federal Windfall Profits Tax), local property taxes on mineral reserves, and lease payments such as royalties must all come out of the economic rent.

The debate over wellhead price regulation of natural gas is, likewise, a struggle over potential economic rent which has historically been shifted to consumers. Deregulation would shift this "windfall" consumer benefit back into economic rent, with the rent distributed among producers, private landowners and governments via royalties and taxes, just as occurred with oil price deregulation in 1980.

The upheavals in world energy markets that followed the 1973-74 Arab oil embargo and the 1978-79 Iranian revolution caused a huge increase in potential or actual economic rents associated with the production of energy commodities. One prominent result of these events was a complex redistribution of income and wealth, from energy consumers, energy-intensive industries, and energy-importing regions to energy producers and energy-exporting regions. Another feature was a radical redistribution of relative shares of income and wealth within the energy-producing and energy-consuming sectors. Energy policy took on greater prominence in the 1970s at the federal and state levels as various interest groups maneuvered to capture or allocate the "windfall" economic rent created by rising world oil prices.

The recent rhetoric of energy sectionalism has in large part been a reflection of the growth and redistribution of energy resource rents that took place between 1972 and 1981. The State of Alaska and its citizens were obviously major beneficiaries of this upheaval. The 1980s, however, are likely to be a decade of stable or falling energy prices, shrinking economic rents, and reduced expectations regarding future economic rents. In such a period, an understanding of the issues can (1) put the various current proposals aimed at further redistribution into proper perspective, and (2) assess the degree to which attempts by various levels of government to capture rent might reduce domestic production and state and national economic activity (and ultimately revenue collections). This analysis may also (1) help identify legislative strategies for states such as Alaska that depend disproportionately

on energy resource revenues, and (2) suggest some elements of national policy that would benefit both energy-importing and energy-exporting regions.¹

Objectives of the Study

To review, the basic objective of the study is to examine how federal policies affect the size and distribution of economic rent derived from Alaska oil and gas development, and by comparison petroleum development in other states. Specific objectives of the study are:

- (1) provision of data and analysis needed to review policies to redistribute petroleum revenues in proper perspective
- (2) assessment of the effect that the size of the government shares of economic rents, or the way in which they are collected, may have on production and, indirectly, on revenues
- (3) aid in evaluating the effect of uncertain geologic, market or policy variables on sharing of economic rents among the various parties. This analysis uncovers the economic incentives associated with methods of collecting economic rent that give birth, sustenance and decline to legislative initiatives for redistribution.

We are not in a position (nor is anyone else) to compute the potential losses from future Alaska production up to, say, the year 2010 since we do not know where or how much oil will be discovered by then, how much it will be worth, or how much it will cost to produce. However, we do provide some benchmark estimates to illustrate the size of effects on hypothetical future production relative to the assumed magnitude of the geologic resource.

Basic Methodology

We have chosen in this study to limit our consideration of generation and distribution of petroleum wealth to the extractive process itself. That is, we examine the value of petroleum exploration, development, and operation of oil and gas fields. We ignore, however, the influence of transportation, refining, marketing and other downstream effects.

¹The previous several paragraphs have been adapted from remarks of Arlon Tussing (personal communication, July 10, 1983).

There are two principle reasons for limiting the scope of the study essentially to wellhead value of petroleum extraction. One is an economic distinction relating to the generation of economic rent. Economic rent (defined simply, as before, to mean the value of a commodity in excess of its cost of production) in downstream activities, such as they might exist, would principally be derived from the exercise of market power by firms in the industry. Economic rent from petroleum production, on the other hand, derives at least in part from the discovery of highly productive natural resources.

The other main reason for limiting the scope of the study to basic petroleum production follows from the first reason. The origin of potential economic rent in the industry provides a rationale for a different approach for public policy toward these "unearned windfalls." Where rent results from market power in transportation or refining, public policy would seek to eliminate such monopoly power by stimulating competition or by stiffening price regulation. Where rent results from fortuitous discovery of particularly valuable natural assets, there is a rationale for public policy to seek to redistribute rather than eliminate such windfalls.

Since the study objective is to assess the influence of federal policies on oil and gas development and revenues, it is important to be able to examine whether effects noted for Alaska are unique to that state, or whether they apply more generally to other petroleum-producing states as well. In order to make this assessment, the study compares the historical pattern of generation and distribution of economic rents from oil and gas production in Alaska to those arising from oil and production in the state of Texas.

Texas is particularly appropriate as a reference point from which to examine the impact of federal policies on Alaska for a number of reasons. Texas has historically been the largest oil-producing state and also has a pattern of government and industry institutions and economic climate for oil development that is dramatically different from Alaska. Unlike Alaska, where nearly all oil and gas production occurs on public lands, approximately 90 percent of production in Texas occurs on private lands. Many of these private lands are owned by individuals. This situation creates both a powerful local constituency affected by government policy toward the petroleum industry and a more decentralized distribution of economic rent derived from petroleum production.

The economic environment for petroleum development in Alaska also differs radically from that of Texas. Alaska's remoteness from major oil-consuming areas causes oil prices in southern coastal Alaska to average about \$3 per barrel lower than prices in Texas while North Slope oil prices average more than \$10 per barrel lower. Since the transportation costs per unit of value are so much larger for gas than for oil, the price difference is even larger for

natural gas. Prices for Cook Inlet gas are less than one-half the average Texas gas price, and North Slope gas is not yet marketable at all.

Cost differentials between the two states further widen the "regional economic gap." Drilling costs are ten to thirty times as high in Alaska as in Texas, where easy road access is available for most well sites. Texas offers easily accessible, available transportation from oil and gas pipelines as well as a vast service industry and other infrastructure.

Thus, because of its major differences in institutions and economic climate, Texas provides a unique opportunity to test hypotheses about distribution of petroleum rents. If a proposition appears to hold for Alaska and Texas at the same time, then there are strong reasons to believe that it has a more general validity for other producing areas in the United States.

Despite the major economic and institutional differences, Texas and Alaska do share two important characteristics. On the one hand, the economies and state treasuries of both states depend strongly upon the health of the petroleum industry. On the other, the two states have large adjacent federal outer continental shelves, with major petroleum potential and major local impacts.

Summary of the Report

The following chapter summarizes oil and gas production, prices, and revenues received by federal and state governments in Alaska and Texas. It provides the basic data needed for deriving any historical analysis of generation and distribution of economic rent from petroleum extraction. The data are summarized by region and by landowner so that one may obtain a clear picture of the pattern as it evolves over time in response to economic fluctuations, geologic factors (such as the discovery of the Prudhoe Bay field on Alaska's North Slope), and political factors which follow. The data summarized in Chapter II show clearly the rising revenues at all levels of government in both Alaska and Texas following the international oil market upheavals of 1972-1981.

Chapter III accounts for the generation and distribution of economic rent from oil and gas production over the past twenty years in Alaska and Texas. This chapter goes beyond Chapter II by examining private shares as well as government shares of petroleum economic rent. It analyzes the degree to which the historical pattern of distribution observed is due to the separate influences of international market pressures, national policy, the regional economic environment, geologic good fortune, and the level of taxation. The analysis illustrates the similarities and differences between the two states by testing several hypotheses about the size

and distribution of economic rent. The results show that no single factor is responsible for the observed pattern; the historical sharing of economic rent resulted from a complex interaction of many factors.

Chapter IV outlines the economics of petroleum exploration, development, and production in Alaska, with some comparisons to Texas. The analysis emphasizes the combined effects of lease terms and tax structure on feasibility of exploration and development by private industry, especially the manner in which risk affects investment decisions of the firm. The chapter provides several examples to illustrate the combined effects of royalty shares and excise taxes on feasibility of Alaska petroleum development.

Chapter V presents some quantitative estimates of the future pattern of economic rents derived from Alaska petroleum development. The purpose is not to forecast actual levels of production and revenues. Rather, the chapter seeks to describe the sensitivity of such activity, particularly on North Slope fields which contain most of the state's known hydrocarbon resources, to market shifts and tax policy. The goal of this chapter is to examine the effect of federal petroleum policy on Alaska production and revenues. We estimate the effects of several hypothetical initiatives, including limiting state severance taxes, extending the Windfall Profits Tax, lifting export restrictions on oil moved through the Trans-Alaska Pipeline, and OCS revenue sharing.

Chapter VI discusses the history of federal legislation on sharing with the states and their local governments revenues received from disposal of natural resources on public lands. The chapter provides a framework for cataloguing the diverse federal revenue-sharing programs. The legislative history demonstrates a consistent pattern of increasing redistribution of federal resource revenues to state and local governments affected by federal resource development. Current proposals in Congress to share a portion of federal Outer Continental Shelf revenues with coastal states, the exception to the rule of federal resource revenue sharing, are not consistent with the historical precedents established over the past 80 years for other federal lands.

The last chapter briefly summarizes the study and the main conclusions reached in Chapters II through VI. It emphasizes the areas in which Alaska and Texas share a common sensitivity to federal policy toward petroleum development. The most significant areas of similarity noted for the two states are (1) the harmful economic and fiscal effects of federal wellhead price regulation and excise taxation of oil and gas production, and (2) the economic and fiscal effects, both beneficial and adverse, of OCS development.

CHAPTER II

HISTORY OF OIL AND GAS PRODUCTION AND REVENUES IN ALASKA, WITH A COMPARISON TO TEXAS

This chapter presents a statistical summary of the historical growth of oil and gas production and revenues in Alaska. We begin by (1) reviewing the history of oil and gas production in the Cook Inlet and the North Slope regions of the state, and (2) the evolution of the markets for this production as evidenced in regional wellhead prices. We then discuss the pattern of growth in revenues received by federal, state, and local governments from Alaska production. We review payments for oil and gas leases on federal and state lands as well as taxes paid to federal, state, and local governments on petroleum exploration and extraction activities.

We have compiled data on actual and estimated production, price, tax, and lease payments by calendar year to the maximum extent feasible. This enables a direct comparison of the size and distribution of all oil and gas revenues across regions, landowners, and political jurisdictions. Supplementary tables in Appendix A provide additional calendar year oil and gas production, price, and revenue data for Alaska regions.

We have used this historical information to examine the distribution of lease and tax revenues received by federal, state, and local governments. The actual distribution of petroleum revenues depends in part on specific provisions for sharing some of this revenue among levels of government. Of particular interest is the manner in which the distribution may have changed in the late 1970s as a result of world market upheaval and the commencement of production from the Prudhoe Bay field.

We then turn to the history of oil and gas production, prices, and government revenues in Texas in order to examine similarities and differences in size and distribution as compared to the pattern observed for Alaska. We note that the pattern in Texas is quite similar to that observed in Alaska, and that the most striking differences are easily explained by institutional factors peculiar to one state or the other.

Petroleum Production and Value in Alaska

Alaska Oil and Gas Production

In 1983, Alaska oil production climbed to a record rate of over 1.7 million barrels per day, while net natural gas production increased to 773 million cubic feet per day. Table 1 shows historical Alaska oil production by field. Table 2 shows annual regional net production of natural gas in Alaska.

TABLE 1
CRUDE OIL PRODUCTION IN ALASKA BY FIELD, 1959-1983
(thousands of barrels)

Year	COOK INLET						NORTH SLOPE		TOTAL ALL FIELDS
	Beaver Creek	Granite Point	McArthur River	Middle Ground Shoal	Swanson River	Trading Bay	Prudhoe ^a Bay	Kuparuk River	
1959	—	—	—	—	187	—	—	—	187
1960	—	—	—	—	578	—	—	—	578
1961	—	—	—	—	6,327	—	—	—	6,327
1962	—	—	—	—	10,259	—	—	—	10,259
1963	—	—	—	—	10,740	—	—	—	10,740
1964	—	—	—	—	11,054	—	—	—	11,054
1965	—	2	1	27	11,099	2	—	—	11,131
1966	—	0	1	2,649	11,711	0	—	—	14,362
1967	—	7,052	749	7,404	12,980	729	—	—	28,913
1968	—	13,131	21,782	14,134	13,619	3,477	—	—	66,144
1969	—	9,183	31,301	10,467	13,151	9,936	60	—	74,098
1970	—	7,522	40,165	12,719	12,408	9,600	320	—	82,735
1971	—	5,577	40,537	11,304	11,466	8,744	324	—	77,952
1972	—	4,663	40,774	9,720	8,896	8,585	130	—	72,769
1973	416	4,767	38,884	10,239	10,064	7,825	127	—	72,322
1974	375	4,237	39,137	9,001	9,765	7,587	525	—	70,627
1975	322	4,361	40,876	8,670	8,754	6,128	723	—	69,833
1976	302	4,471	35,810	8,864	7,591	5,366	995	—	63,398
1977	276	4,711	33,235	7,616	5,981	4,276	113,107	—	169,201
1978	223	4,862	30,223	6,382	4,870	3,567	397,679	—	447,805
1979	211	4,613	25,440	5,423	4,344	2,892	468,412	—	511,335
1980	214	4,394	20,894	4,854	3,724	2,167	555,394	—	591,641
1981	180	3,981	18,022	4,291	2,938	1,666	555,173	1,092	587,342
1982	182	3,467	15,806	3,573	2,992	1,384	559,100	32,406	618,910
1983	170	3,550	13,564	3,381	3,017	1,081	560,884	39,879	625,526

^aValues reflect oil production net of injection, includes production from Lisburne pool.

SOURCE: Alaska Oil and Gas Conservation Commission.

TABLE 2
ALASKA NET NATURAL GAS PRODUCTION^a
(billions of cubic feet)

<u>Calendar Year</u>	<u>Statewide Production</u>	<u>North Slope Production^b</u>	<u>Cook Inlet Production</u>
Before 1971	329.7	6.4	323.3
1971	155.6	1.4	154.2
1972	148.0	1.4	146.6
1973	136.7	1.4	135.3
1974	144.5	2.8	141.7
1975	156.6	3.8	152.8
1976	157.2	5.9	151.3
1977	187.4	27.7	159.7
1978	214.4	37.0	177.4
1979	226.5	43.3	183.2
1980	230.1	51.6	178.5
1981	247.0	53.7	193.3
1982	260.4	65.8	194.6
1983	282.2	72.6	209.6

^aValues reflect total casinghead gas and dry gas production net of injection.

^bNorth Slope production equals production from South Barrow, East Barrow, Prudhoe Bay, and Kuparuk fields.

SOURCE: Alaska Oil and Gas Conservation Commission.

Prior to the start-up of commercial production from Prudhoe Bay in mid-1977, Alaska oil and gas development was essentially limited to the Cook Inlet region. Although exploration has taken place in other areas of the state, the only field to have produced outside the Cook Inlet or North Slope regions is the small Katalla field, east of Cordova. This field produced a total of 154,000 barrels of oil during the first three decades of the 20th century. Alaska oil and gas production may be summarized regionally as follows.

Cook Inlet: Commercial oil and gas production from the Cook Inlet area began in 1959 with the Swanson River field, located on the Kenai National Wildlife Refuge. In the 1960s, offshore discoveries on state-leased lands added four major oil fields as well as substantial gas reserves. By 1977, cumulative oil production from the Cook Inlet region had reached approximately 740 million barrels. From a peak production rate of over 210,000 barrels per day in 1970, oil production from the Cook Inlet region declined to 170,000 barrels per day in 1976, and to 68,000 barrels per day in 1983.

Of the five major Cook Inlet oil fields, just one--McArthur River--has produced nearly 500 million barrels, or over one-half of all the oil produced in the region. The Swanson River field, with a cumulative production of 200 million barrels, is the second largest. Except for production from the Swanson River and the small Beaver Creek field also located on the federal wildlife refuge, all Cook Inlet oil production has occurred on state lands. Barring an unexpected discovery, oil production in the region is unlikely to reverse the trend of decline since around 90 percent of original known oil reserves of the region has been depleted.¹

Net gas production from the Cook Inlet region, shown in Table 2, remained relatively constant between 1971 and 1977 at roughly 150 billion cubic feet (bcf) per year. Since 1977, however, increased demand in the Anchorage market has caused annual production to increase to over 200 bcf in 1983. Four major fields account for nearly all regional gas production: McArthur River, Kenai, Beluga River and North Cook Inlet. Two of these fields, Kenai and Beluga River, have multiple private (Cook Inlet Region, Inc.), federal, and state ownership, while the other two lie wholly under state tidelands. Unlike the situation with oil, substantial gas reserves in Cook Inlet remain undeveloped.

North Slope: Oil production started on the North Slope at Prudhoe Bay in 1969 with approximately 60,000 net barrels produced in field development tests, as shown in Table 1. Commercial production at Prudhoe began in June of 1977. The Kuparuk River field was brought into commercial production at the end of 1981, and pilot project production of the Lisburne oil pool at Prudhoe Bay occurred in 1982 and 1983.

The two major oil and gas fields (Prudhoe Bay and Kuparuk River) on the North Slope occur entirely on lands leased by the State of Alaska. The only other producing fields on the North Slope are the East Barrow and South Barrow gas fields, owned and operated by the U. S. Department of the Interior. Initially developed to provide energy for a federal research facility in the Barrow area, Congress has approved a bill (PL 98-366) to transfer operation of the fields to the North Slope Borough.

In the absence of a feasible transportation system to export markets, net North Slope gas production has been limited to local uses. The East and South Barrow fields have produced approximately 17 bcf for use in the Barrow vicinity.²

The remainder of North Slope gas production has been consumed by production-related uses at Prudhoe and Kuparuk, including fuel for pump stations along the Trans-Alaska Pipeline.

Value of Alaska Oil and Gas Production

The total value of production can be measured at the wellhead by product of marketed production and the wellhead price. Consistent estimates of wellhead values require a consistent definition for measuring both the prices and the quantities. Since nearly all Alaska production occurs on public lands, one consistent method is to use accounting procedures that public land managing agencies employ for royalties. Another consistent method for measuring marketed production and prices is that employed by the state for assessing severance taxes.

These two methods used by public agencies may yield different results for both prices and quantities. Both are subject to dispute, litigation, and revision over time but are preferred to other sources because of the greater amount of information available in the public domain. Although discrepancies in production data are slight, severance tax and royalty price differences may be large for state leases, even after correcting for the deduction of certain field costs from state royalties. This occurs because of the special contracts often used by the state for selling royalty oil and gas in kind.

We have chosen to make maximum use of the information contained in both the severance tax wellhead production and price conventions and the royalty accounting data. Where available, we use royalty data to measure and value the government royalty shares of Alaska oil and gas production and severance tax data to measure and value the private shares. Where royalty and tax data are unavailable in the earlier years, we have relied on industry sources to fill in the gaps.

Tables 3 and 4 present annual regional marketed production of Alaska oil and gas, respectively. The regional series for marketed

oil production corresponds closely to the net production data by field presented in Table 1. The difference in the two sets of figures reflects a minor difference in definition (marketed production includes gas condensate, a negligible amount historically in Alaska) and a difference in timing of recording of production (there is a delay of a month or two in recording of marketed production).

Regional marketed gas production, shown in Table 4, is significantly lower than net wellhead production presented in Table 2. The major source of this discrepancy is gas vented or flared, which is produced but not marketed. Marketed production also does not include large amounts of gas used for field fuel (since 1976), mainly on the North Slope. Total marketed production of Alaska natural gas reached 200 bcf in 1982, or about 77 percent of net production.

Table 5 presents weighted average annual wellhead prices calculated for marketed production of oil and gas by Alaska region. Cook Inlet oil prices remained nearly constant at around \$3 per barrel until the 1973-74 events occurring in the Middle East. The average price rose slowly under federal price controls during the 1970s to around \$6 per barrel in 1979. After full oil price decontrol in 1981, Cook Inlet oil prices rose to \$30 per barrel in 1981, declining to around \$28 in 1982.

Federal price controls had little direct effect on North Slope oil. Weighted average Prudhoe Bay oil prices, as measured at Pump Station No. 1 of the Trans-Alaska Pipeline, were initially comparable to Cook Inlet prices. Decontrolled North Slope oil prices rose sooner than Cook Inlet prices during the 1979-81 international oil market upheaval, but did not rise as far, remaining \$7 to \$8 lower in 1981 and 1982. This difference is due mainly to the pipeline tariff from Prudhoe Bay to Valdez, but lower quality crude and excess supply in the West Coast oil market are contributing factors.

Average prices for Cook Inlet natural gas, as shown in Table 5, have remained low, ranging from 12 cents to 66 cents per thousand cubic feet (mcf) between 1959 and 1982. North Slope gas from the Prudhoe Bay and Kuparuk reservoirs has been priced according to ceiling prices allowed under the 1978 Natural Gas Policy Act, averaging around \$1.70 per mcf.

Table 6 shows the time series of total value of oil and gas production in the Cook Inlet region, divided into the government royalty shares of oil and gas and the private share. The actual government royalty share has been around one-eighth of the oil. (Federal and state royalty shares amounted to one-eighth of gross production but the prices paid for the government and the private shares may vary.) The effective royalty rate for gas has been somewhat lower because of the production from private lands.

TABLE 3
ALASKA MARKETING OIL PRODUCTION BY REGION, 1959-1982^a
(millions of barrels)

	<u>Cook Inlet</u>	<u>North Slope</u>	<u>Total</u>
1959	0.187	0.	0.187
1960	0.559	0.	0.559
1961	6.327	0.	6.327
1962	10.259	0.	10.259
1963	10.740	0.	10.740
1964	11.059	0.	11.059
1965	11.128	0.	11.128
1966	14.358	0.	14.358
1967	29.126	0.	29.126
1968	66.204	0.	66.204
1969	73.953	0.	73.953
1970	83.616	0.	83.616
1971	79.494	0.	79.494
1972	72.893	0.	72.893
1973	72.323	0.	72.323
1974	70.603	0.	70.603
1975	69.834	0.	69.834
1976	63.398	0.	63.398
1977	56.445	112.756	169.201
1978	50.452	398.167	448.619
1979	43.053	467.000	510.053
1980	36.280	555.613	591.893
1981	31.867	556.479	588.346
1982	27.867	591.515	619.382

^aIncludes lease condensate.

SOURCE: 1959-1976: American Petroleum Institute.

1977-1982: Sum of taxable production for Alaska severance taxes (Alaska Department of Revenue, Division of Petroleum Revenue) and royalty production (Alaska Department of Natural Resources, Division of Oil and Gas, and U.S. Department of Interior, Minerals Management Service).

TABLE 4
ALASKA MARKETING NATURAL GAS PRODUCTION BY REGION,
1959-1982

(billions of cubic feet)^a

	<u>Cook Inlet</u>	<u>North Slope</u>	<u>Total</u>
1959	0.133	0.	0.133
1960	0.246	0.	0.246
1961	0.631	0.	0.631
1962	2.184	0.	2.184
1963	4.498	0.	4.498
1964	6.238	0.	6.238
1965	7.255	0.	7.255
1966	11.267	0.	11.267
1967	14.438	0.	14.438
1968	17.343	0.	17.343
1969	50.864	0.	50.864
1970	111.576	0.	111.576
1971	121.618	0.	121.618
1972	125.596	0.	125.596
1973	131.007	0.	131.007
1974	128.935	0.	128.935
1975	160.270	0.	160.270
1976	166.072	0.	166.072
1977	153.014	1.956	154.970
1978	163.499	7.182	170.681
1979	168.355	8.973	177.328
1980	160.388	10.894	171.282
1981	176.685	11.559	188.244
1982	186.974	12.977	199.951

^a1959-1976: includes gas used on lease for fuel. 1977-1982: excludes gas used on lease for fuel.

SOURCE: 1959-1976: American Petroleum Institute (represents gross production net of reinjection and gas vented and flared).

1977-1982: Sum of taxable production for Alaska severance taxes (Alaska Department of Revenue, Division of Petroleum Revenue) and royalty production (Alaska Department of Natural Resources, Division of Oil and Gas, and U.S. Department of Interior, Minerals Management Service).

TABLE 5
ALASKA WEIGHTED AVERAGE ANNUAL WELLHEAD PRICES
BY REGION, 1959-1982

	OIL		GAS	
	(Dollars per Barrel)		(Dollars per Thousand Cubic Feet)	
	<u>Cook Inlet</u>	<u>North Slope</u>	<u>Cook Inlet</u>	<u>North Slope</u>
1959	1.58	0.	0.12	0.
1960	2.2	0.	0.122	0.
1961	2.79	0.	0.204	0.
1962	3.04	0.	0.214	0.
1963	3.04	0.	0.247	0.
1964	3.04	0.	0.276	0.
1965	3.06	0.	0.248	0.
1966	3.06	0.	0.248	0.
1967	3.13	0.	0.25	0.
1968	2.82	0.	0.253	0.
1969	2.9	0.	0.259	0.
1970	3.01	0.	0.246	0.
1971	3.24	0.	0.147	0.
1972	3.23	0.	0.147	0.
1973	3.62	0.	0.149	0.
1974	4.92	0.	0.17	0.
1975	5.22	0.	0.302	0.
1976	5.03	0.	0.389	0.
1977	5.259	6.131	0.394	1.066
1978	5.588	5.024	0.491	1.194
1979	6.053	10.479	0.657	1.751
1980	10.062	16.728	0.544	1.843
1981	30.053	23.175	0.591	1.748
1982	27.793	19.686	0.591	1.699

SOURCE: 1959-1976: American Petroleum Institute.

1977-1982: Weighted average of taxable and royalty shares. Sum of taxable production for Alaska severance taxes (Alaska Department of Revenue, Division of Petroleum Revenue) and royalty production (Alaska Department of Natural Resources, Division of Oil and Gas, and U.S. Department of Interior, Minerals Management Service).

TABLE II.6.
VALUE OF OIL AND GAS PRODUCED FROM ALASKA'S
COOK INLET REGION, 1963-1982
(millions of dollars)

	<u>Government Royalty Shares</u>		<u>Private Royalties and Nonroyalty Production</u>	<u>Total Value</u>
	<u>Oil</u>	<u>Gas</u>		
1963	4.018	0.103	29.640	33.761
1964	4.213	0.037	31.091	35.341
1965	4.161	0.088	31.602	35.851
1966	5.349	0.354	41.027	46.730
1967	9.088	0.426	85.260	94.774
1968	22.226	0.768	168.089	191.083
1969	25.646	1.093	200.899	227.637
1970	30.864	2.045	246.223	279.132
1971	37.449	2.024	235.965	275.438
1972	34.256	2.197	217.454	253.907
1973	37.314	2.243	241.772	281.329
1974	49.539	2.545	317.202	369.285
1975	47.637	5.038	360.260	412.935
1976	43.809	6.13	333.554	383.493
1977	34.557	6.709	315.782	357.048
1978	35.241	7.643	319.394	362.278
1979	33.438	9.602	328.245	371.285
1980	39.509	11.079	401.725	452.313
1981	116.026	18.349	927.675	1,062.050
1982	97.755	17.236	770.014	885.005

SOURCE: Columns 1 and 2: U.S. Department of Interior, Minerals Management Service and Alaska Department of Natural Resources, Division of Oil and Gas; Column 4: product of production from Tables 2, 4, and price from Table 5; Column 3: difference between Column 4 and sum of Columns 1 and 2.

Total annual value of Cook Inlet petroleum rose from \$30 million in the early 1960s (from the Swanson River field) to over \$200 million in 1969 with the development of the offshore fields. In spite of the oil production decline, rising oil prices and gas sales caused the value to increase steadily until it reached a peak of one billion dollars in 1981.

North Slope oil and gas values are summarized in Table 7. It is clear from the royalty shares (approximately one-eighth of the value for both oil and gas) that gas sales do not contribute a significant share of the value. Total North Slope petroleum wellhead value rose with the wellhead price and expanding production to nearly \$13 billion in 1981, falling to \$11.7 billion in 1982.

Alaska Oil and Gas Revenues

Government revenues derived from oil and gas production include all lease payments to public landowners for the rights to explore for and produce oil and gas and all taxes on petroleum exploration and production. In Alaska, revenues have primarily accrued to the federal and state governments, while a relatively small portion of the revenue has been collected by local governments. Except for a portion of several gas fields underlying the former Kenai and Tyonek Indian Reservations, all producing oil and gas properties in the state are owned by either the federal or state government. Pursuant to the Alaska Native Claims Settlement Act, Cook Inlet Region, Inc., acquired the leases on the Indian lands.

Lease Payments

Forms of payment for Alaska oil and gas leases on public lands may include cash bonus bids, rental payments, oil and gas royalties, and net profit shares. Although there are many active leases in Alaska containing net profit shares, historically none has yet produced any commercial value of oil or gas. The size and distribution of lease revenues depends upon which lands are considered more valuable by industry at the time of disposal as well as upon where oil or gas may be found. The terms of the lease may also greatly affect when the public landowner receives revenues as well as the total amount received. We pursue this topic further in Chapter IV.

Table 8 shows payments received for oil and gas leases on federal lands in Alaska from 1971 to 1982. Because of different administrative policies and jurisdictional issues governing federal oil and gas lands, it is appropriate to divide federal oil and gas acreage into onshore property and OCS lands.³

Historically, most federal lease payment revenues have come in the form of bonus bids for OCS lease sales, as shown in Table 8.

TABLE II.7.
VALUE OF OIL AND GAS PRODUCED FROM ALASKA'S
NORTH SLOPE REGION, 1977-1982
(millions of dollars)

	<u>Government Royalty Shares</u>		<u>Nonroyalty</u>	<u>Total</u>
	<u>Oil</u>	<u>Gas</u>	<u>Production</u>	<u>Value</u>
Before				
1977	0.	0.	0.	0.
1977	78.731	0.263	614.389	693.383
1978	223.709	1.084	1,783.977	2,008.770
1979	582.271	1.373	4,325.846	4,909.490
1980	1,115.64	1.826	8,196.694	9,314.160
1981	1,570.99	2.168	11,343.442	12,916.600
1982	1,423.18	2.599	10,240.721	11,666.500

SOURCE: Columns 1 and 2, Alaska Department of Natural Resources, Division of Oil and Gas; Column 4: product of production from Tables 2, 4, and price from Table 5; Column 3: difference between Column 4 and sum of Columns 1 and 2.

TABLE 8
PAYMENTS FOR ALASKA FEDERAL LEASES, CALENDAR YEAR 1971-1982
(thousands of current dollars)

REVENUE SOURCE	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
<u>Onshore Leases</u>												
Bonus Bids ^a	0	0	0	0	0	0	0	0	0	0	0	53,299
Rentals ^a	213	355	289	338	314	286	6	4	1	291	6	5,215
Oil Royalties ^b	4,857	3,753	5,143	7,740	6,136	5,224	4,191	3,443	3,599	4,752	11,418	10,920
Gas Royalties ^b	1,127	1,235	1,189	1,310	2,010	2,401	2,580	3,593	4,013	6,245	9,748	13,210
<u>OCS Leases^c</u>												
Bonus Bids	0	0	0	0	0	559,837	398,471	0	488,691	109,751	4,576	2,056,000
Rentals	0	0	0	0	0	1,230	2,834	2,834	2,321	2,230	1,879	3,240
Oil Royalties	0	0	0	0	0	0	0	0	0	0	0	0
Gas Royalties	0	0	0	0	0	0	0	0	0	0	0	0

^aSource: Bureau of Land Management, Data Processing.

^bRoyalty values based on volume of production. Includes contributions made to the ANCSA Alaska Native Fund.
Source: U.S. Department of Interior, Minerals Management Service.

^cSource: U.S. Department of Interior, Minerals Management Service.

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Bonus bids from competitive federal onshore lease sales were limited to the recent sale program for the National Petroleum Reserve on the North Slope. Royalty payments from onshore production in the Cook Inlet Region accounts for the next largest revenue stream, with lease rentals providing a small share of revenue. As described below, payments for federal onshore leases shown in Table 8 have been shared with the state of Alaska.

In contrast to federal lease payments, the major portion of state lease payments for the period 1971-1982, shown in Table 9, have come from oil and gas royalties associated with production from the Prudhoe Bay field. The largest sum in bonus bids came in 1969 with the \$900 million North Slope sale held after the Prudhoe discovery. The single large bonus bid figure in Table 9 reflects the State of Alaska's share of the joint federal-state Beaufort Sea sale held in 1979.

Oil and Gas Taxes

Taxes levied on exploration and production of oil and gas include excise taxes on production, property taxes on tangible property such as drilling equipment and production facilities or on oil and gas reserves, and taxes on income earned from production.

State Taxes: The State of Alaska has raised revenues from five different oil and gas taxes. These include conservation taxes, severance taxes, corporate income taxes, property taxes, and a temporary reserves tax. Table 10 shows total revenues raised by these five Alaska oil and gas taxes for the period 1971-1982.

The Alaska State Oil and Gas Regulation and Conservation Tax was enacted in 1973 and applies only to oil production [AS43.57]. It is a nonescalating tax of one-eighth of a cent per barrel. The conservation tax exists primarily as a mechanism to charge to industry the cost of regulatory activities of the Alaska Oil and Gas Conservation Commission.

The Alaska State Oil and Gas Properties Production Tax is a severance tax levied upon the producer of oil from each lease or property. The tax has been revised numerous times over the years.⁵ Currently, it is based on either the percentage-of-value amount or the cents-per-barrel amount, whichever is greater, multiplied by an economic limit factor [AS43.55]. The percentage-of-value amount remains 12.25 percent of the value of the production for a property coming into production after June 30, 1981, for its first five years of production. Thereafter, and for all other production including Prudhoe Bay, the percentage-of-value amount has been 15 percent since July 1, 1981. The cents-per-barrel amount equals \$0.60 per barrel of crude oil and \$0.80 per barrel for all other taxable oil.

TABLE 9
PAYMENTS FOR ALASKA STATE LEASES, CALENDAR YEAR 1971-1982
(thousands of current dollars)

<u>REVENUE SOURCE</u>	<u>1971</u>	<u>1972</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1982</u>
Bonus Bids ^a	456	2,883	25,949	1,041	0	0	0	0	567,549	12,387	5,824	61,270
Rentals ^b	3,048	2,984	2,537	3,605	3,424	2,777	2,683	2,189	2,069	5,541	6,610	3,245
Oil Royalties ^c	19,540	22,230	25,500	32,760	33,860	32,700	109,100	255,500	612,100	1,150,000	1,676,000	1,510,000
Gas Royalties ^c	897	962	1,054	1,235	3,028	3,729	4,392	5,134	6,962	6,660	10,770	6,630

^aSource: Alaska Department of Natural Resources, "Competitive Oil and Gas Leasing of State Lands" (7/21/83). Includes eleven sales (24, 25, 26, 27, 28, 29, 29B, 30, 31, 32, 33).

^bSource: Alaska Oil and Gas Conservation Commission (1971-1980); Alaska Department of Natural Resources, Division of Administrative Revenue Unit (1981, 1982).

^cRoyalty values calculated on the basis of production volume and wellhead price. Source: Alaska Department of Natural Resources, Division of Oil and Gas.

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TABLE 10
ALASKA STATE OIL AND GAS TAXES^a, CALENDAR YEAR 1971-1982
(thousands of current dollars)

REVENUE SOURCE	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Conservation Tax ^b	0	0	0	71	77	79	63	163	247	308	626	341
Severance Tax ^c	11,410	12,340	10,890	22,090	27,560	25,900	52,590	149,100	256,800	829,600	1,492,000	1,566,000
Oil	10,790	11,690	10,210	21,330	25,860	24,420	51,290	144,000	246,600	819,700	1,480,000	1,558,000
Gas	620	650	680	760	1,700	1,486	1,298	5,064	10,190	9,900	11,740	7,800
Corporate Income Tax ^c	0	0	0	0	0	0	0	0	474,400	693,200	822,700	318,600
Property Tax ^d	0	0	0	9,179	12,052	24,238	46,327	58,540	69,982	77,432	95,165	123,666
Reserves Tax ^c	0	0	0	0	0	223,100	270,600	0	0	0	0	0

^aincludes local government shares of property taxes on petroleum production and exploration property.

^bSource: Alaska Oil and Gas Conservation Commission (1971-1980), represents taxes due; Alaska Department of Revenue, Cumulative Statement of Revenue Collected, monthly statements (1981-1982), represents taxes paid.

^cSource: Alaska Department of Revenue, Cumulative Statement of Revenue Collected (monthly statements).

^dFigures shown reflect gross taxes for production and exploration property. Includes municipal and local government credits. Values calculated as two percent (20 mills) of historical assessed value by property type. Source: Alaska Department of Revenue, Division of Petroleum Revenue, Petroleum Property Assessor, and Alaska Department of Community and Regional Affairs, Alaska Taxable.

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The economic limit factor is a provision that arbitrarily reduces the effective tax rate as the production rate per well declines, so that at the "economic limit" the effective tax rate is zero. The lower bound for the economic limit is set presumptively by statute at 300 barrels per day per well for oil and 3,000 mcf per day for gas.⁶

The severance tax is also levied on gas production calculated as the greater of either \$6.4 cents per thousand cubic feet of taxable gas, or ten percent of the gross value of taxable production calculated at the point of production, multiplied by an economic limit factor. Alaska severance tax revenue has climbed from \$11 million in 1971 to \$1.5 billion in 1981 and 1982. Ninety-five to ninety-nine percent of the total severance tax collections have come from oil.

Alaska has a corporate income tax with a marginal tax rate of 9.4 percent [AS43.20]. Between 1979 and 1981, the state collected a special income tax based on the corporate income derived from oil and gas production within Alaska rather than on income apportioned to Alaska under conventional interstate apportionment formulas [AS43.21]. Since July 1, 1981, there is a special apportionment formula for oil and gas production and transportation activities. Approximately \$2 billion collected under the separate accounting method is under litigation.

The state Oil and Gas Exploration, Production and Pipeline Transportation Property Tax is levied at 20 mills annually on the full and true value of all taxable property [AS43.56]. Reserves are not included in the definition of taxable property. First-class cities and boroughs may also levy taxes on oil and gas properties. In this case, the state reimburses the local governments for the tax collected at the local mill rate, up to 20 mills. Following our convention of defining oil and gas value at the wellhead, we exclude property taxes on petroleum transportation property in the figures in Table 10. Property taxes on production and exploration property rose to over \$120 million by 1982.

In 1975, the Alaska Legislature established a temporary Oil and Gas Reserves Ad Valorem Tax on the value of oil and gas "in-place" [AS43.58]. Revenues collected with this tax measure were credited against future severance tax payments from Prudhoe Bay. The reserves tax raised, or more correctly, borrowed one-half billion dollars before commercial production began from that field in 1977.

Federal Taxes: Federal taxes on oil and gas development in Alaska include the Windfall Profits Tax and the corporate income tax. The federal Windfall Profits Tax is an excise tax on production of crude oil levied since 1980 as part of the deregulation of domestic oil prices. The rate structure is complex, and effective ad valorem rates range from zero to around 50 percent

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of wellhead value. Taxpayers (oil producers) may deduct state severance taxes (up to 15 percent). State royalty shares are not taxed but the tax is collected for accounting purposes from federal royalty shares.⁷

Table 11 contains estimates of federal Windfall Profits Tax and corporate income tax paid on Alaska oil and gas production. These estimates are derived from the analysis contained in Chapter III. Windfall Profits Taxes were nearly \$2.9 billion for 1981 and half that amount in 1982. Corporate income taxes were negative until 1978 (net tax loss from deductions for exploration and development expenses, mainly on the North Slope), then rose to around \$2 billion in 1980.⁸

Distribution of Oil and Gas Revenues

Although the state and federal governments collect all oil and gas lease payments and taxes in Alaska, local governments have also benefited from sharing of the petroleum property tax. The federal government also shares 90 percent of onshore federal lease payments (except 50 percent of lease payments on the National Petroleum Reserve [NPRA]) with the State of Alaska. However, as noted above, federal Windfall Profits Tax is subtracted from federal oil royalties before sharing with the state.

Table 11 shows the final distribution of oil and gas revenues among the major taxing authorities and lease holding interests. This table reflects the sharing of federal onshore lease revenues with the State of Alaska as well as the sharing of state petroleum property taxes with local governments. For comparison, lease rentals and royalties from former Indian reservation lands now belonging to Cook Inlet Region, Inc., are also shown in Table 11.

A summary of the distribution of oil and gas revenues from Table 11 appears in Table 12. This table shows that, on a very broad level, the total revenue streams accruing to the federal and state governments have been around the same magnitude. Larger state revenues from royalties and severance taxes have been offset by larger federal corporate income taxes, bonus bids, and, recently, by the Windfall Profits Tax. However, federal revenues have increased more rapidly than state revenues since 1980. By 1982, federal revenues, even after sharing onshore lease payments with the state, were nearly 50 percent higher than combined state and local petroleum revenues.

Oil and Gas Production and Revenues in Texas

This section examines oil and gas production by ownership, analyzing the distribution of lease revenues and taxes based on production among federal, state, and local governments. Texas has historically been the largest oil producing state, with Alaska moving into second place after the Prudhoe Bay field came into

TABLE 11
DISTRIBUTION OF ALASKA OIL AND GAS REVENUES
CALENDAR YEAR 1971-1982
(thousands of current dollars)

Revenue Recipient and Revenue Source	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Federal Government^a												
Bonuses-Federal Lands	0	0	0	0	0	559,837	398,471	0	488,691	109,751	4,576	2,082,650
Rentals-Federal Lands	21	36	29	34	31	1,259	2,835	2,834	2,331	2,259	1,800	3,762
Royalties-Federal Lands	598	499	633	905	815	763	677	704	761	1,010	1,514	1,857
Windfall Profits Tax ^e	0	0	0	0	0	0	0	0	0	762,600	2,896,700	1,463,500
Corporate Income Tax ^e	-133,000	-144,200	-59,100	-90,300	-291,800	-453,600	-383,700	23,900	736,500	1,857,900	1,993,800	1,698,100
State Government												
Bonuses-Federal Lands ^b	0	0	0	0	0	0	0	0	0	0	0	26,650
Bonuses-State Lands	456	2,883	25,949	1,041	0	0	0	0	567,549	12,387	5,824	61,270
Rentals-State Lands	3,048	2,984	2,537	3,605	3,424	2,777	2,683	2,189	2,069	5,541	6,610	3,245
Rentals-Federal Lands ^b	192	320	260	304	283	257	5	4	1	262	5	4,694
Royalties-State Lands	20,437	23,192	26,554	33,995	36,888	36,429	113,492	260,634	619,062	1,156,660	1,686,770	1,516,630
Royalties-Federal Lands ^b	5,386	4,489	5,699	8,145	7,331	6,863	6,094	6,332	6,851	9,092	13,618	16,715
Conservation Tax	0	0	0	71	77	79	63	163	247	308	624	341
Severance Tax	11,410	12,340	10,890	22,090	27,560	25,900	52,590	149,100	256,800	829,600	1,492,000	1,566,000
Property Tax	0	0	0	4,950	6,812	13,401	29,545	42,486	36,751	40,871	23,893	30,224
Reserves Tax	0	0	0	0	0	223,100	270,600	0	0	0	0	0
Special Corporate Income Tax	0	0	0	0	0	0	0	0	474,400	693,200	822,700	318,600
Local Government^c												
Property Tax - NSB	0	0	*	2,223	2,863	8,151	14,168	13,736	31,914	34,864	69,803	92,080
Property Tax - KPB	2,200	2,264	2,250	1,996	2,377	2,686	2,563	2,274	1,281	1,672	1,440	1,334
Yakutat	0	0	0	0	0	0	55	44	36	27	28	28
Cook Inlet Region, Inc.^d												
Rents and Royalties	2	*	*	*	*	*	*	*	*	*	9,600	*

See notes on following page.

Notes for Table 11.

*Not available.

- Less than 0.5.

^aValues for bonuses from Table 8. Note that federal OCS revenues are not presently shared with the state. Values for federal share of bonus and rental payments reflect ten percent of the payments collected from onshore lands as provided by the Alaska Statehood Act (includes contributions paid into the Alaska Native Fund), except 50 percent of revenue from the National Petroleum Reserve Alaska (1982 only).

^bNinety percent of the value of federal rentals and royalties (net of windfall profits tax) as provided for by the Alaska Statehood Act (includes payments made into the Alaska Native Fund), except 50 percent of NPRA revenues. Property Taxes from Table A.11. Other tax values from Table 3.

^cProperty tax values shown reflect local government shares of petroleum property taxes as provided for by AS 43.56.

^dEstimated value of rental and royalty payments from federally leased onshore lands in Cook Inlet selected by CIRI. 1971 figure for Kenai Indian Reservation.

^eEstimated as described in Chapter III, shown in Tables E.1, E.2, E.3. We deducted from actual state corporate income tax 46 percent of the difference between actual state corporate tax collections and those calculated in Chapter III using model HISTOIL. HISTOIL estimates of state corporate income tax in millions of current dollars for the period 1978-1982, respectively, are \$6.6, \$207.9, \$479.3, \$278.6, and 0. Windfall profits tax charged to federal royalties, as per statute. Negative corporate profits tax figures reflect net reduction in federal tax receipts from deductible Alaska industry expenditures.

TABLE 12
SUMMARY OF THE DISTRIBUTION OF ALASKA OIL AND GAS REVENUES^a
CALENDAR YEAR 1971-1982
(millions of dollars)

	<u>1971</u>	<u>1972</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1982</u>
Federal Government	-132.4	-143.7	-58.4	-89.4	-291.0	108.2	18.2	27.4	1,228.3	2,733.6	4,898.5	5,249.9
State Government	40.9	46.2	71.9	74.2	82.4	308.8	475.1	460.9	1,963.7	2,747.9	4,052.1	3,597.7
Local Government ^b	*	*	*	4.2	5.2	10.8	16.8	16.1	34.2	36.6	71.3	93.4

*Not available.

^aSource: Table 11.

^bShare of oil and gas property taxes on production and exploration property paid to local governments.

X

production in the late 1970s. The two states combined account for over 50 percent of domestic U.S. oil production. In contrast to Alaska, Texas is also a very large producer of natural gas. The Gulf of Mexico offshore from the coasts of Texas and Louisiana is one of the largest gas producing provinces of the United States. Although there are many differences in the political economy of oil and gas between Alaska and Texas, the two states share both an economic dependence and a fiscal dependence on the industry.

Texas Oil and Gas Production

Tables 13 and 14 show historical production of oil and gas in Texas since 1954, respectively, separating federal Outer Continental Shelf (OCS) production from that within Texas state jurisdiction. Texas state submerged lands extend three leagues (approximately 10 miles) offshore rather than the usual three miles, following the legal history of the original Spanish territory claimed by the state. Oil and gas production from the remaining federal OCS was correspondingly smaller until leases from the more remote OCS began coming into production in the late 1970s.

Over the period 1954-1982, total Texas oil production fluctuated from approximately 900 to 1,200 million barrels per year. This surpasses current Alaska production by around 50 to 100 percent. Since the peak production year in 1972 of 1,265 million barrels, annual production has declined to around 900 million barrels. OCS oil production has expanded rapidly since 1977, reaching 17 million barrels a year by 1982.

Texas natural gas production rose from around 6 trillion cubic feet a year in the 1950s to 9.5 trillion cubic feet in the early 1970s, although the peak year for Texas natural gas production was also 1972. Total annual gas production has remained over 7 trillion cubic feet until 1982, with declining onshore production offset by expanding OCS production. The share of marketed production in the total has risen from around 85 percent in the 1950s to 95 percent in recent years as a consequence of rising market prices. As a point of contrast with oil, offshore areas in the Gulf of Mexico make a significant contribution to Texas natural gas production. Combined federal and state offshore production exceeded one trillion cubic feet by 1982.⁹

Value of Texas Oil Production

This study examines the distribution of revenues from oil and gas development net of transportation, refining, etc. Thus, it is necessary to estimate weighted average wellhead values for oil and gas production in Texas. As in Alaska, two consistent definitions can be applied systematically throughout the state's diverse oil and gas fields: (1) the royalty in-value price and (2) the definition of value for severance tax purposes. In Texas, the severance tax base

TABLE 13
TEXAS OIL PRODUCTION
(million barrels)

<u>Year</u>	<u>State Jurisdiction</u>	<u>Outer Continental Shelf</u>	<u>Total^a Petro- leum Liquids Production</u>
1954	954	0	974
1955	1,002	-	1,053
1956	1,079	-	1,108
1957	1,058	-	1,074
1958	910	0	940
1959	944	0	972
1960	892	0	927
1961	895	0	939
1962	894	-	943
1963	915	-	978
1964	929	-	990
1965	933	-	1,058
1966	1,000	1	1,057
1967	1,074	3	1,120
1968	1,088	3	1,133
1969	1,107	3	1,152
1970	1,208	2	1,250
1971	1,182	2	1,223
1972	1,263	2	1,302
1973	1,257	2	1,295
1974	1,225	1	1,262
1975	1,186	1	1,222
1976	1,154	1	1,190
1977	1,101	1	1,138
1978	1,041	2	1,074
1979	979	4	1,018
1980	931	11	977
1981	898	14	945
1982	877	17	925

-Negligible production (less than 0.5 million barrels).

^aTotal includes lease condensate (not included in state production figures).

SOURCE: State jurisdiction - Texas Railroad Commission.

Federal jurisdiction - U.S. Department of the Interior,
Minerals Management Service.

Total Production - Basic Petroleum Data Book, Vol. III,
No. 3 (September 1983), American Petroleum Institute.

TABLE 14
TEXAS NATURAL GAS PRODUCTION
(billion cubic feet)

	<u>State Jurisdiction</u>	<u>Outer Continental Shelf</u>	<u>Total Marketed Production^a</u>
1954	5,511	0	4,551
1955	5,740	0	4,731
1956	6,005	0	5,000
1957	6,037	-	5,156
1958	6,050	0	5,178
1959	6,422	0	5,719
1960	6,675	0	5,893
1961	6,794	0	5,964
1962	6,906	0	6,080
1963	7,214	0	6,205
1964	7,554	0	6,490
1965	7,855	0	6,637
1966	8,098	42	6,954
1967	8,337	100	7,189
1968	8,613	110	7,495
1969	8,963	127	7,853
1970	9,450	133	8,358
1971	9,571	127	8,551
1972	9,603	147	8,658
1973	9,341	149	8,514
1974	8,907	160	8,171
1975	8,052	123	7,486
1976	7,708	93	7,192
1977	7,565	87	7,051
1978	7,077	232	6,548
1979	7,116	512	7,175
1980	6,998	625	7,252
1981	6,733	730	7,050
1982	6,036	858	6,441 ^b

-Negligible production (less than 0.5 billion cubic feet).

^aMarketed production defined as gross production net of gas injection and quantity vented or flared.

^bISER estimate, published series not available.

SOURCE: State jurisdiction - Texas Railroad Commission.

Federal jurisdiction - U.S. Department of the Interior,
Minerals Management Service.

Total Production - Basic Petroleum Data Book, Vol. III, No. 3
(September 1983), American Petroleum Institute.

allows certain field cost deductions not permitted for state royalty accounting, but the overall difference in price is small for most fields.¹⁰

Unlike Alaska, however, most production occurs on private property, so no royalty data exist for estimating weighted-average wellhead prices. Consequently, the severance tax base provides the best standard for production on private lands. Table 15 presents estimates of total petroleum liquids values with public royalty shares separated into federal OCS, federal onshore, and two major state land categories, and with private shares divided into federal OCS and Texas state jurisdiction. Petroleum liquids include crude oil and natural gas liquids, or condensate, from gas wells. Disaggregated, as in Table 15, the state nonroyalty value estimate should correspond to the base for the state severance tax, while the sum of the state and federal OCS nonroyalty shares (and, technically, the federal royalty shares) include the tax base for the federal Windfall Profits Tax.

Total value of oil and condensate climbed from 9.6 to 32.5 billion dollars between 1975 and 1982, with most of the change occurring after decontrol of oil prices in 1979. State royalty shares of oil and condensate have been roughly evenly divided between the two major land-managing agencies, the General Land Office and the University of Texas System. Aided by an increase in offshore production, state and federal royalty shares have increased from 0.6 percent to 1.1 percent of the total. It is immediately obvious from the figures in Table 15 that federal onshore production does not play a significant role in Texas oil production and revenues.

Value of Texas Gas Production

Table 16 contains estimates of the value of natural gas production, divided into public royalty and private production. The methodology for preparing this table is as discussed above with respect to oil in Table 15. Total estimated value of Texas natural gas production grew from \$4 billion in 1975 to \$14 billion in 1981, averaging around 40 percent of the oil values. The increase in the value of gas has been more gradual than that of oil, however, due to the nature of interstate gas price regulation and long-term contracts prevailing in the industry. Federal and state royalty shares are a more significant fraction of gas production than of oil, rising from 2.3 percent of total production in 1975 to 4.3 percent by 1981. The proportion of gas production allocated for government royalties in Texas is undoubtedly still growing, reflecting the increasing importance of the publicly-owned offshore resources of the Gulf of Mexico.

TABLE 15
VALUE OF PUBLIC AND PRIVATE PRODUCTION
OF OIL AND CONDENSATE IN TEXAS BY CALENDAR YEAR
(million dollars)

Year	Public Royalty Shares					Private Royalties and Nonroyalty Production		
	Federal OCS	Federal Onshore	General Land Office	University of Texas	Total	Federal OCS	State Jurisdiction	Total
1975	1.6	0.1	25.3	33.5	60.4	8.1	9537.5	9545.6
1976	1.8	0.1	27.9	36.2	66.0	9.0	9720.1	9729.1
1977	1.5	0.2	33.8	37.5	72.9	7.6	9648.4	9656.0
1978	3.9	0.1	43.9	41.7	89.6	19.5	9944.9	9964.4
1979	7.2	0.2	52.3	53.1	112.9	36.0	12700.7	12736.7
1980	33.1	0.4	86.8	87.3	207.6	165.7	21065.1	21230.8
1981	73.1	0.7	146.5	128.5	348.8	365.5	31745.0	32110.5
1982	93.3	0.6	141.8	122.4 ^a	358.1	466.5	27744.9	28211.4

TABLE 16
VALUE OF PUBLIC AND PRIVATE PRODUCTION
OF NATURAL GAS IN TEXAS BY CALENDAR YEAR
(million dollars)

Year	Public Royalty Shares					Private Royalties and Nonroyalty Production		
	Federal OCS	Federal Onshore	General Land Office	University of Texas	Total	Federal OCS	State Jurisdiction	Total
1975	5.8	0.1	58.0	29.1	93.0	28.9	3939	3967.9
1976	4.9	0.1	91.9	34.3	131.1	24.2	5372	5396.2
1977	8.7	0.1	132.4	37.9	179.1	43.4	6669	6712.4
1978	47.7	0.1	138.3	33.5	219.6	238.3	6838	7076.3
1979	149.7	0.1	158.1	33.7	341.6	748.3	8482	9230.3
1980	217.5	0.2	249.2	36.8	503.7	1087.6	10335	11422.6
1981	301.9	0.2	261.4	43.3	606.8	1510.1	11938	13448.1
1982	383.3	0.4	243.6	37.8 ^a	665.1	1915.7	12314	14229.7

^aextrapolated from first eight months.

SOURCES: Federal figures computed from data from U.S. Department of the Interior, Minerals Management Service. State royalty figures from state of Texas General Land Office, Energy Resources and the University of Texas System, University Lands Accounting Office. State nonroyalty production from State of Texas, Comptroller of Public Accounts, Revenue Estimation.

Lease Payments to Landowners in Texas

All revenues from state oil and gas leases in Texas can be grouped in one of four categories: (1) lease bonus payments, (2) lease rental payments, (3) oil royalties, and (4) gas royalties. Net profit shares, working interests, and other forms of participation are not used for state leases. Federal law permits net profit share bidding for OCS leases, but there were no producing net profit share leases as of 1982. The federal government also assesses minimum royalties for OCS tracts which are deductible from royalty payments, but these are of little quantitative significance.

Federal Leases: Federal leases may be divided into two categories, Outer Continental Shelf and Onshore. Table 17 shows federal lease revenues by type from OCS leases since 1954. The total fluctuates considerably from year to year, reflecting the high proportion of bonus bids in the total. Royalties have risen from negligible quantities to over \$400 million per year since 1977, while bonuses peaked at \$2.6 billion in 1981. Average annual lease payments for the Texas federal OCS in the years 1979-1982 were \$1.65 billion. None of this revenue is shared with Texas state and local governments.

When Texas entered the United States, it retained its public domain as state land. Thus, there has never been a federal public domain in Texas. Over the years, the federal government has acquired significant acreage of Texas land for such purposes as national forests, national parks, and military reservations. Some of this acquired land in Texas contains oil and gas deposits, although the total amount produced is small. Table 18 shows onshore federal lease payments from 1954 to 1981. Although oil and gas have been produced in every year, combined royalties never reached one million dollars during this period.

Texas federal onshore production is divided fairly evenly between military lands and national grasslands. Lease revenue from military lands is not shared with state and local governments. Although national grasslands are administered by the national forests, which share 25 percent of receipts with the state, the 25 percent share of grassland revenues is distributed directly to the county of origin. Thus, the federal government shares a very small annual stream of onshore lease revenues with Texas local governments but not with the state government.

State Leases: The state of Texas had a very limited tax base when it joined the United States. The new state sold its lands for revenue or traded them for various public services, including military service and building the state capital. Approximately 3 million acres remain in state fee title ownership today, of which approximately two-thirds is endowed to the University of Texas. The state land grant to the University has proven fortuitous to the recipients--over 20 percent of the 2 million acres of west Texas rangeland is now under productive oil and gas lease.

TABLE 17
PAYMENTS FOR TEXAS FEDERAL OFFSHORE LEASES BY CALENDAR YEAR
(million dollars)

<u>Year</u>	<u>Bonus Payments</u>	<u>Rental Payments</u>	<u>Minimum Royalties</u>	<u>Oil Royalties</u>	<u>Gas Royalties</u>	<u>Total</u>
1954	23.357	0.289	0	0	0	23.646
1955	8.437	0.537	0	0.001	0	8.975
1956	0	0.696	0	0.007	0	.703
1957	0	0.29	0.001	0.003	0	.294
1958	0	0.236	0	0	0	.236
1959	0	0.064	0	0	0	.064
1960	35.732	0.763	0.017	0	0	36.512
1961	0	0.679	0.019	0	0	.698
1962	0.558	0.502	0.021	0.002	0	1.083
1963	0	0.424	0.036	0.027	0	.487
1964	0	0.369	0.035	0.002	0	.406
1965	0	0.337	0.09	0.002	0	.429
1966	0	0.003	0	0.444	1.15	1.597
1967	0	0.244	0.003	1.488	2.85	4.585
1968	593.899	1.727	0.004	1.665	3.01	600.305
1969	0	1.642	0	1.592	3.41	6.644
1970	0	1.358	0.029	1.326	3.47	6.183
1971	0	1.073	0.268	1.044	3.33	5.715
1972	0	0.602	0.232	1.095	4.13	6.059
1973	1537.5	1.724	0.302	1.18	4.63	1545.336
1974	1494.12	3.571	0.302	1.613	5.28	1504.886
1975	345.396	5.722	0.216	1.59	5.78	358.704
1976	68.493	5.429	0.285	1.779	4.86	80.846
1977	356.102	5.443	0.423	1.515	8.68	372.163
1978	589.248	5.144	0.697	3.858	47.65	646.597
1979	639.636	4.01	0.9	7.203	149.69	801.439
1980	1417.96	3.797	0.928	33.143	217.45	1673.278
1981	2649.63	4.448	0.912	73.084	301.92	3029.994
1982	609.178	3.994	0.932	93.323	383.33	1090.757

^aIncludes entire western Gulf of Mexico (area-wide lease sales).

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

TABLE 18
PAYMENTS FOR FEDERAL ONSHORE LEASES IN TEXAS BY CALENDAR YEAR
(million dollars)

<u>Year</u>	<u>Bonus Payments</u>	<u>Rental Payments</u>	<u>Oil Royalties</u>	<u>Gas Royalties</u>	<u>Total</u>
1954	*	*	0.009	0.008	0.018
1955	*	*	0.009	0.008	0.017
1956	*	*	0.093	0.012	0.106
1957	*	*	0.147	0.031	0.179
1958	*	*	0.107	0.024	0.132
1959	*	*	0.089	0.018	0.106
1960	*	*	0.105	0.033	0.138
1961	*	*	0.275	0.156	0.431
1962	*	*	0.203	0.121	0.323
1963	*	*	0.177	0.095	0.270
1964	*	*	0.303	0.104	0.407
1965	*	*	0.283	0.116	0.401
1966	*	*	0.245	0.121	0.365
1967	*	*	0.197	0.13	0.326
1968	*	*	0.168	0.068	0.236
1969	*	*	0.119	0.089	0.207
1970	*	*	0.104	0.086	0.190
1971	*	*	0.125	0.08	0.206
1972	*	*	0.126	0.088	0.213
1973	*	*	0.112	0.137	0.249
1974	*	*	0.132	0.07	0.202
1975	*	*	0.105	0.129	0.234
1976	*	*	0.125	0.057	0.182
1977	*	*	0.173	0.117	0.29
1978	*	*	0.143	0.113	0.255
1979	*	*	0.190	0.126	0.315
1980	1.261	*	0.389	0.158	0.549
1981	*	*	0.685	0.185	0.870
1982	1.251	*	0.590	0.359	0.949

*Not available.

SOURCE: U.S. Department of the Interior, Minerals Management Service, and Bureau of Land Management.

Remaining state lands are managed by the Texas General Land Office (GLO). Although the GLO manages less than one million acres of fee title lands, the agency controls about 13.5 million acres of subsurface estate. In addition to small amounts of miscellaneous categories, the state subsurface domain includes 5 million acres of submerged lands (including beneath the Gulf of Mexico out to three leagues from the coastline) and 6 million acres of upland subsurface rights of "Relinquishment Act" lands. Lands in the latter category were state lands for which the GLO retained subsurface rights when disposing of the surface estate.

Although the GLO aggressively manages its offshore and upland fee properties, the agency purposefully takes a passive role with Relinquishment Act leases. The surface owner, not the GLO, takes the initiative to lease the mineral rights. Although the GLO requires the lease payments to be some combination of bonus payments, rental payments, and royalties, the surface owner is free to negotiate the specific terms. In exchange for performing the service of agent for the state (and for retaining political support for the GLO and its elected commissioner), the surface owner retains a 50 percent share of all lease payments. Thus, for every dollar of bonus, rental, and royalty paid to the GLO from Relinquishment Act leases, private owners received an equal share. In 1982, the state's share of Relinquishment Act royalties was around \$100 million.

Although all Texas state lease terms specify a combination of bonuses, rentals, and royalties, royalty rates may differ widely from lease to lease even in the same producing area. Around 20 years ago, the GLO raised the standard royalty share from one-eighth to one-sixth. The share increased to one-fifth for new leases in 1974 and to one-fourth for leases sold since 1979. Royalty shares on University lands followed the same upward trend, lagging a year or so behind the GLO. In addition, the GLO has held a number of royalty bid sales in recent years on submerged lands.

Table 19 shows bonus receipts for Texas state lease sales since 1959 by the major categories of state land. All lease revenues from over 99 percent of all subsurface acreage managed by the GLO, including submerged lands, are dedicated to the Permanent School Fund. This fund is an endowment for public primary and secondary education whose annual earnings are distributed to local school districts on the basis of school-age population. Lease bonuses have averaged around \$80 million per year since 1974. The GLO collected around \$10 million per year prior to 1974, although the yearly total fluctuates considerably depending on exploration trends.

Rental payments for Texas state leases are shown in Table 20. Although data are not available for the special funds category, one should recall that this category comprises less than 1 percent of GLO lands. Not counting the negligible amount from the special

TABLE 19
BONUS PAYMENTS FOR TEXAS STATE LEASES BY FISCAL YEAR
(million dollars)

<u>General Land Office</u>						
<u>Year</u>	<u>Offshore</u>	<u>Other School Lands</u>	<u>Special Funds</u>	<u>Total GLO</u>	<u>University of Texas</u>	<u>State Total</u>
1959	0	5.436	0.208	5.644	*	*
1960	0.258	7.413	0.207	7.878	*	*
1961	3.229	11.21	0.233	14.672	*	*
1962	0.297	5.486	0	5.783	*	*
1963	2.617	6.974	0	9.591	*	*
1964	2.435	8.29	0.724	11.449	*	*
1965	53.115	9.64	0.03	62.785	*	*
1966	18.223	12.39	0.105	30.718	*	*
1967	3.641	4.168	0.006	7.815	*	*
1968	1.252	7.43	0.094	8.776	*	*
1969	1.838	6.183	0	8.021	*	*
1970	5.995	5.688	0.102	11.785	*	*
1971	4.326	5.631	0.046	10.003	*	*
1972	1.36	3.967	0.013	5.34	*	*
1973	3.701	10.441	0.14	14.282	*	*
1974	32.982	18.503	0.463	51.948	11.398	63.346
1975	5.32	11.612	0.655	17.587	8.043	25.63
1976	6.198	12.883	0.023	19.104	15.403	34.507
1977	41.343	19.871	0.363	61.577	13.582	75.159
1978	49.808	25.252	0.64	75.7	18.423	94.123
1979	34.578	16.889	0.009	51.476	10.723	62.199
1980	34.733	33.122	1.905	69.76	0.253	70.013
1981	37.467	58.333	6.628	102.428	98.132	200.56
1982	*	*	0.946	71.4	19.371	90.771

*Not available.

SOURCE: State of Texas, General Land Office, Energy Resources, and University of Texas System Administration.

TABLE 20
RENTAL PAYMENTS FOR TEXAS STATE LEASES BY FISCAL YEAR
(million dollars)

<u>General Land Office</u>						
<u>Year</u>	<u>Offshore</u>	<u>Other School Lands</u>	<u>Special Funds</u>	<u>Total GLO¹</u>	<u>University of Texas</u>	<u>State Totals^a</u>
1959	0.144	1.95	*	2.094	*	*
1960	0.098	2.051	*	2.149	*	*
1961	0.069	2.258	*	2.327	*	*
1962	0.127	2.609	*	2.736	*	*
1963	0.177	1.81	*	1.987	*	*
1964	0.525	2.7	*	3.225	*	*
1965	0.755	3.549	*	4.304	*	*
1966	3.163	2.942	*	6.105	*	*
1967	3.711	3.133	*	6.844	*	*
1968	2.684	2.35	*	5.034	*	*
1969	1.492	1.956	*	3.448	*	*
1970	0.618	1.596	*	2.214	*	*
1971	0.726	1.361	*	2.087	*	*
1972	0.963	1.453	*	2.416	*	*
1973	0.92	1.371	*	2.291	*	*
1974	1.066	1.686	*	2.752	0.477	3.229
1975	2.935	2.571	*	5.506	0.698	6.204
1976	3.223	2.574	*	5.797	0.56	6.357
1977	2.405	2.795	*	5.2	1.116	6.316
1978	4.776	2.344	*	7.12	1.403	8.523
1979	7.319	3.477	*	10.796	2.337	13.133
1980	10.293	2.665	*	12.958	2.55	15.508
1981	13.048	3.738	*	16.786	2.954	19.74
1982	*	*	*	19.355	2.558	21.913

*Not available.

^aExcluding special funds.

SOURCE: State of Texas, General Land Office, Resource Management,
and University of Texas System Administration.

funds lands, state rental payments have climbed from \$3 million per year in 1974 to over \$20 million per year. About 15 percent of the total comes from University lands, reflecting the share of these lands in the total state acreage.

Table 21 shows oil and gas royalty payments from the University lands and from the same three categories of GLO lands. The relative shares in the total for the GLO lands and University lands of oil royalties and gas royalties are shown as well in Tables 15 and 16, respectively.

Total oil and gas royalties for GLO lands have grown more than tenfold during the past ten years while University lands royalties have increased by a factor of five. Total state royalties reached one-half billion by 1981. The relative share of the University lands in the total has declined from around 40 percent to around 30 percent over the past ten years. Tables 15 and 16 show clearly that the shift is due to the increasing role of state gas production, mostly from submerged lands with a relatively high royalty share, in total royalty collections.

Taxes on Oil and Gas Production in Texas

State Taxes: The state of Texas levies production taxes on oil and gas which are analogous to the Alaska oil and gas severance taxes. The state also collects a regulation tax of 3/16 cent per barrel of oil produced to finance the oil and gas activities of the Railroad Commission, the state regulatory agency in Texas whose portfolio includes oil and gas conservation. The regulation tax is similar to Alaska's 1/8 cent-per-barrel conservation tax, and yields between 1.8 and 2 million dollars per year in revenues. Texas has no state income tax.

The sales tax provides a major source of revenue in Texas. However, since all industries pay this tax, we shall not consider it here as a tax on oil and gas development.¹¹ The Texas severance tax is assessed at 4.6 percent of wellhead value for oil (or 4.6 cents per barrel, whichever is greater) and 7.5 percent of wellhead value for gas. Condensate is taxed at the lower oil tax rate. Royalty shares accruing to public landowners are exempt from taxation, as is the case in Alaska.

Table 22 shows oil and gas production taxes for oil and for natural gas since 1960. By 1981, the annual revenue stream surpassed the \$2 billion mark, with gas revenues accounting for around 40 percent of the total. As one would expect from the ad valorem rates, this amounts to around 5 percent of total oil and gas production value excluding public royalty shares.

TABLE 21
TOTAL OIL AND GAS ROYALTY PAYMENTS FROM
TEXAS STATE LEASES BY FISCAL YEAR
(million dollars)

<u>General Land Office</u>						
<u>Year</u>	<u>Offshore</u>	<u>Other School Lands</u>	<u>Special Funds</u>	<u>Total GLO</u>	<u>University of Texas</u>	<u>State Total</u>
1971	4.917	24.306	*	30.877	*	*
1972	5.235	23.452	*	*	*	*
1973	4.646	23.844	0.205	28.695	*	*
1974	7.67	35.138	0.659	43.467	32.562	76.029
1975	19.066	50.053	0.71	69.829	57.492	127.321
1976	29.327	75.738	0.789	105.854	69.684	175.538
1977	40.448	111.552	0.92	152.92	75.284	228.204
1978	63.684	120.27	0.736	184.69	76.251	260.941
1979	58.576	123.769	0.705	183.05	73.906	256.956
1980	155.28	154.341	1.108	310.729	115.381	426.11
1981	168.559	210.518	1.584	380.661	154.546	535.207
1982	*	*	0.003	404.661	172.991	577.652

*Not available.

SOURCE: State of Texas, General Land Office, Energy Resources, and University of Texas System, University Lands Accounting Office.

TABLE 22
TEXAS STATE TAXES ON OIL AND GAS RECEIVED BY FISCAL YEAR
(million dollars)

<u>Year</u>	<u>Oil & Condensate^a Production Tax</u>	<u>Natural Gas Production Tax</u>	<u>Total</u>
1960	124.538	52.233	176.771
1961	122.389	57.895	180.284
1962	122.586	60.199	182.785
1963	123.794	64.051	187.845
1964	126.723	66.476	193.199
1965	126.596	72.495	199.091
1966	133.027	74.185	207.212
1967	142.516	78.323	220.839
1968	158.044	81.868	239.912
1969	156.245	84.408	240.653
1970	172.601	96.377	268.978
1971	194.824	108.809	303.633
1972	192.988	114.38	307.368
1972	209.895	124.902	334.797
1974	347.161	171.068	518.229
1975	404.764	259.57	664.334
1976	431.315	364.588	795.903
1977	428.484	474.318	902.802
1978	437.206	517.844	995.05
1979	466.663	554.354	1021.017
1980	785.691	734.247	1519.938
1981	1290.95	901.931	2192.881
1982	1316.79	1057.06	2373.85

^aIncludes regulation tax of 3/16 of a cent per barrel of oil produced.

SOURCE: State of Texas, Comptroller of Public Accounts, Revenue Estimation.

Table 23 shows that Texas state revenues from oil and gas leases and production taxes totaled \$3 billion in 1981. Although the share of royalties in the total revenue stream has been increasing steadily, mainly from offshore gas, production taxes still account for 70 percent of the total.

Federal Taxes: Since its inception in 1980, the federal Windfall Profits Tax has provided the largest flow of public revenue from Texas oil and gas production. Data are not directly available for Windfall Profits taxes collected from production in each state. We provide, in Table 24, estimates for the federal Windfall Profits Tax and the federal corporate income taxes calculated as described below in Chapter III. The two taxes combined collected over \$9 billion in 1981 according to these estimates.¹²

Local Taxes: Local governments in Texas collect taxes on oil and gas production and exploration property, along with other kinds of real property. Texas also permits ad valorem taxation of oil and gas reserves at "fair market value." The reserves tax base is actually the estimated present value of revenue net of excise taxes and extraction costs.¹³ Table 24 shows our estimates of the sum of property and reserves taxes received by Texas local governments. Local government taxes on oil and gas production rose from around two-thirds of a billion dollars in 1974 to \$2 billion in 1981, approximately the same as state oil and gas taxes.¹⁴

Distribution of Texas Oil and Gas Revenues

Table 24 shows the complete distribution of Texas oil and gas revenues to federal, state, and local governments. Federal lease revenues have fluctuated between one and three billion dollars recently as a result of some enormous bonus bids for leases in the Gulf of Mexico on top of royalty payments now exceeding \$400 million per year. This represents a change of several orders of magnitude from as recently as the early 1970s, when the total federal lease payments were only \$6 million per year.

The federal government shares virtually none of all these billions of lease revenues with Texas state and local governments. The state receives no shared federal revenues, and counties share between \$50,000 and \$500,000 total per year from onshore federal leases in Texas national grasslands. According to Table 24, the federal government collected a total of \$15.7 billion in Windfall Profits taxes between 1980 and 1982 from oil production in Texas. Thus, the federal government consistently received a larger share of revenue from Texas oil than the combined total shares of the state and local governments. The figures in Table 24 would show an even larger federal share in recent years except for the large income tax deductions and investment credits estimated for recent exploration and development, especially on the federal OCS.

TABLE 23
TOTAL TEXAS STATE OIL AND GAS REVENUES,
BY FISCAL YEAR
(million dollars)

<u>Year</u>	<u>Production Taxes</u>	<u>Royalty Payments</u>	<u>Bonus and Rental Payments</u>	<u>Total</u>
1971	303.633	30.877 ^a	12.09 ^a	346.6 ^a
1972	307.368	*	7.756 ^a	*
1973	334.797	28.695 ^a	16.573 ^a	380.065 ^a
1974	518.229	76.029	66.575	660.833
1975	664.334	127.321	31.834	823.489
1976	795.903	175.538	40.864	1012.305
1977	902.802	228.204	81.475	1212.481
1978	995.05	260.941	102.646	1358.637
1979	1021.017	256.956	75.332	1353.305
1980	1519.938	426.11	85.521	2031.569
1981	2192.881	535.207	220.3	2948.388
1982	2373.85	577.652	112.684	3064.186

^aExclude: University of Texas.

SOURCE: See Tables 19, 20, 21, and 22.

TABLE 24
DISTRIBUTION OF TEXAS PUBLIC OIL AND GAS REVENUES, 1974-1982
(million dollars)

	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1982</u>
<u>Federal Government</u>									
Onshore Lease Payments ^a	0.2	0.2	0.1	0.2	0.2	0.2	1.3	0.5	1.6
OCS Lease Payments ^b	1,504.9	358.7	80.8	372.2	646.6	801.4	1,673.3	3,030.0	1,090.8
Windfall Profits Tax ^c	0	0	0	0	0	0	2,514.6	7,752.5	5,459.8
Corporate Income Tax	<u>2,389.7</u>	<u>2,613.1</u>	<u>2,825.1</u>	<u>2,928.9</u>	<u>2,501.0</u>	<u>3,921.7</u>	<u>1,629.9</u>	<u>1,453.0</u>	<u>1,320.0</u>
Total, Federal Government	3,894.8	2,972.0	2,906.0	3,301.3	3,147.8	4,723.3	5,819.1	12,236.0	7,872.2
 <u>State Government^d</u>	 660.8	 823.5	 1,012.3	 1,212.5	 1,358.6	 1,353.3	 2,031.6	 2,948.4	 3,064.2
 <u>Local Government</u>									
Federal Lease Payments ^a	0.1	0.1	-	0.1	0.1	0.1	0.4	0.2	0.5
Property and Reserves Taxes ^c	<u>669.3</u>	<u>795.7</u>	<u>873.1</u>	<u>916.1</u>	<u>865.7</u>	<u>1,169.3</u>	<u>1,681.6</u>	<u>2,060.0</u>	<u>1,835.5</u>
Total, Local Government	669.4	795.8	873.1	916.2	865.8	1,169.4	1,682.0	2,060.2	1,836.0

-negligible, less than \$0.5 million.

^aTable 19, assuming 25 percent of federal acquired lands leases shared with local government.

^bTable 18.

^cISER estimates described in Chapter III, sum of onshore and offshore, Appendix E, Tables E.4 and E.5.

^dTable 23.

Summary and Conclusions

In 1981, Alaska and Texas collected approximately the same amount of revenue from oil and gas production. Although Texas produced 50 percent more oil and 30 times more gas, Alaska was fortunate to have nearly all of its production occur on state-leased lands or from federal onshore leases sharing 90 percent of the revenues with the state. While lease payments were three times higher in Alaska than in Texas, Texas received much larger oil and gas production tax revenues. Even though the effective Alaska severance tax rate for oil is three times the Texas rate, the higher wellhead prices and the much larger quantity of taxable production make up the difference. In addition, Texas annually collects a billion dollars in gas production taxes, and its local governments collect at least this amount in property and reserves taxes.

Oil and gas revenues have risen much faster than the rate of inflation in both states, but for different reasons. In Alaska, production from the Prudhoe Bay was primarily responsible for the tremendous leap in state revenues in the late 1970s, but rising prices and tax rates also contributed. In Texas, on the other hand, production of both oil and gas was declining during the 1970s. The nearly tenfold revenue gain resulted completely from rising prices accompanying world market fluctuations and loosening federal price controls.

Although Texas gained a windfall with oil deregulation in 1979-80, the state windfall was small relative to that of the federal government. The federal government was in an excellent position to collect the economic rent generated in Texas by the sudden increase in U.S. oil and gas prices. It collected over \$25 billion between 1980 and 1982 from the Windfall Profits Tax, the corporate income tax, and from bonus bids from recent leasing of massive areas of the Outer Continental Shelf. The federal OCS appears to be the likely source for most discoveries of large oil and gas fields in both states. This comparative examination of the historical pattern of production and revenues suggests that it is the federal government, not the states, that has recently recovered its historically dominant position in collecting resource revenues from oil and gas.

ENDNOTES

¹Alaska Oil and Gas Conservation Commission, Statistical Report, 1983.

²Ibid.

³Although all offshore property was federal prior to Alaska statehood, submerged lands within three miles of shore became state property in 1959. Since there was no offshore leasing in Alaska prior to statehood, one may speak of the federal Outer Continental Shelf as offshore submerged lands beyond the three-mile limit.

⁵The tax was initially enacted in 1955 by the territory at a rate of 1 percent of value. See AS43.55.01.

⁶The economic limit factor for oil production equals:

$$(1 - [PEL/TP]) \exp (460 \times WD/PEL)$$

where: PEL = monthly production rate at the economic limit;

TP = total production during the month for which the tax is to be paid;

WD = Total number of well days for which the tax is to be paid; and

"exp" indicates that the expression following is an exponent.

The economic limit factor (ELF) for gas production equals:

$$1 - PEL/TP.$$

⁷See Appendix D for more detail regarding the rate structure of the federal windfall profits tax.

⁸O.S. Goldsmith and J.P. Rowe, Federal Revenues and Spending in Alaska, ISER, April 1982, estimate for federal fiscal year 1981 for Prudhoe Bay only a windfall profit tax of \$2.6 billion and a corporate income tax of \$2.96 billion. Our corporate income tax estimates include large deductions for exploration and development work on the North Slope in addition to Prudhoe Bay.

⁹Texas state production of 247 billion cubic feet in 1982, from Texas Railroad Commission.

¹⁰Personal communication with Director of University Lands Accounting Office, University of Texas System. Note: This is the reverse of the case of Alaska, in which field costs may be deducted from royalties but not severance taxes.

¹¹Sales taxes paid directly by the oil and gas production and exploration industry were estimated at \$106.2 million in 1982, approximately 5 percent of severance tax revenue collected that year. See "The Petroleum Industry and the Texas Sales Tax," Texas Comptroller of Public Accounts, Revenue Estimating, April 1983.

¹²This compares with an estimate of \$10 billion for the windfall profits tax in 1981 and an increase of \$4 billion in corporate income tax payments between 1979 and 1981 in Peter Mieszkowski and Eric Toder, "Taxation of Energy Resources" Chapter 2 in C. McLure and P. Mieszkowski, ed., Fiscal Federalism and the Taxation of Natural Resources, Lexington Books, 1983, p. 65-92. Mieszkowski overestimates the windfall profits tax by assuming all 1981 oil is Tier I and Tier II and does not include increased exploration and development deductions from corporate taxable income.

¹³See Mieszkowski and Toder, op cit., page 73-74.

¹⁴The estimate includes \$1.355 billion in reserves taxes for 1982, or just over 3 percent of gross production value. This is between the two estimates reported in Mieszkowski and Toder, p. 82.

CHAPTER III

ECONOMIC RENT FROM PETROLEUM DEVELOPMENT AND ITS DISTRIBUTION IN ALASKA AND TEXAS, 1963-1982

Introduction

The preceding chapter discussed the size and historical distribution of petroleum lease and tax revenues in Alaska and Texas among federal, state, and local governments. In this chapter, we go one step further to examine the generation and distribution of petroleum economic rent. As discussed in Chapter I, economic rent is defined as the excess of the value of a commodity above its cost of production.

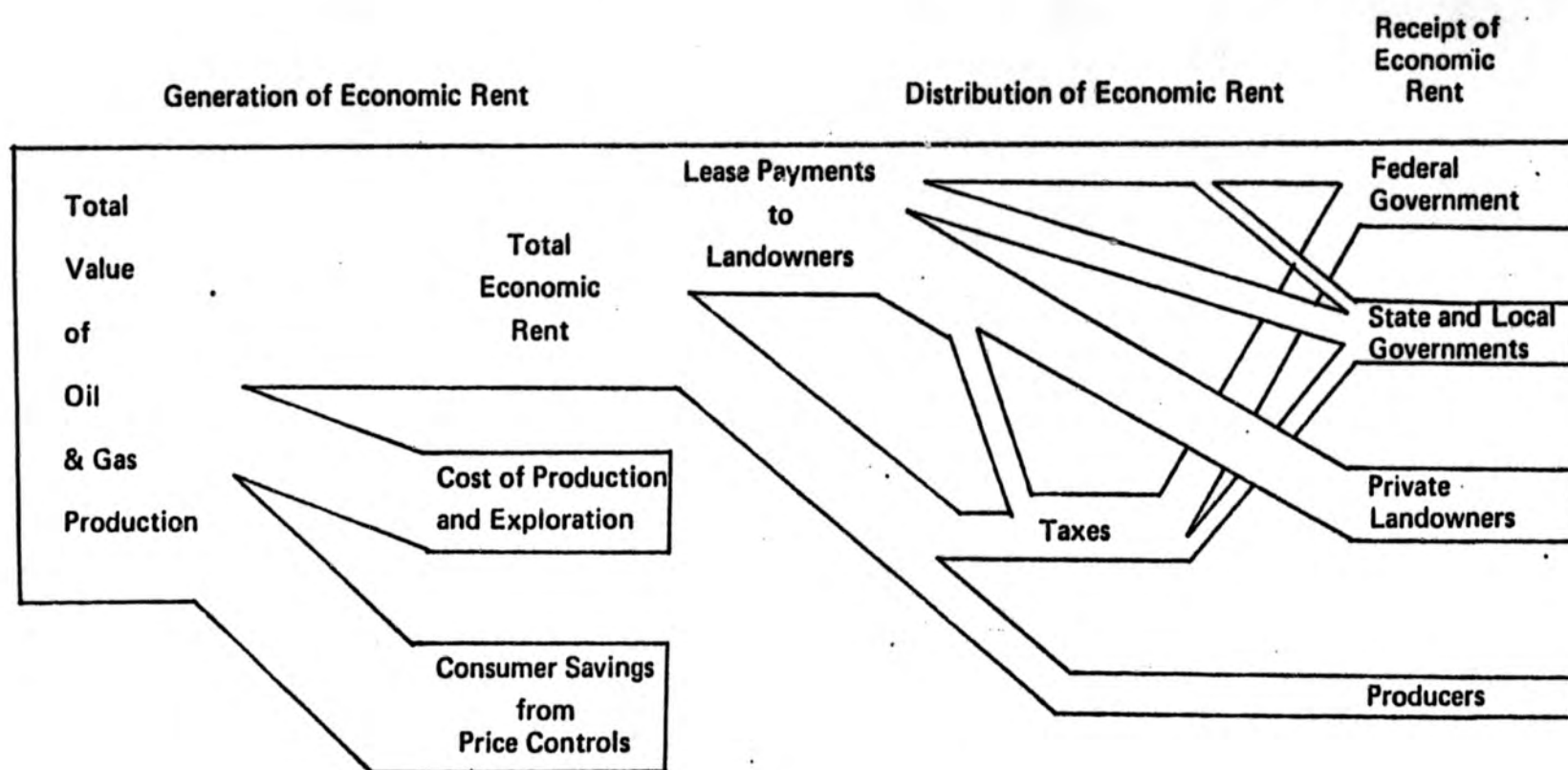
Historical accounting of economic rent generated from oil and gas production requires analysis of several additional factors beyond the accounting of public revenues. Economic rent, like sales or income, is a flow of value from one place to another. The relationship between economic rent and government revenues is most easily illustrated with reference to the flowchart, Figure 1. The total value of oil and gas production derives from the equilibrium of supply and demand in the markets for energy resources.

Moving from left to right along the flowchart, the total value may be divided into two portions--production costs and the residual, economic rent. Figure 1 shows, as well, the potential reduction in total value and in economic rent caused if direct controls are in effect on oil or gas prices. The cost of production in the accounting framework of the flowchart includes capital and operating costs for exploration, development, and operation of oil and gas fields. It does not include lease payments to landowners and taxes on production or economic rent.

Figure 1 shows how lease payments and taxes redistribute the total economic rent among landowners and governments. Some federal lease payments are shared with state and local governments, as discussed in Chapter II. In addition, private landowners typically pay taxes to state and local governments from payments they receive for oil and gas leases on their lands. After the complex pattern of distribution of economic rent has run its course, the residual not allocated to landowners and governments remains with the producing firms and their stockholders.

In Chapter II, we presented historical accounts of all public lease payments and major taxes paid on oil and gas production and exploration. Our task in this chapter is to examine distribution of economic rent, so we wish to include only those taxes that we consider to be paid out of economic rent. Other taxes would be considered part of the cost of production.

Figure 1. Generation and Distribution of Economic Rent from Oil and Gas Production



One can decide whether or not a particular tax is usually paid out of economic rent by hypothesizing a private owner operating a producing oil or gas field, earning no more than the competitive return on exploration and development costs, and paying the same taxes paid on average by nonpetroleum activities. Since all investments must pay these taxes and in the long run earn at least this competitive rate of return, there are no economic rents. Total taxes from this hypothetical oil field should be considered part of the cost of production, and are not paid from economic rent. General sales taxes, real property taxes, and income taxes are in this category.

Income taxes are also paid out of economic rent when profits exceed the competitive cost of capital. As a practical matter, it is difficult to distinguish which portion of income taxes would be paid if there were no economic rents. We have chosen to include as a portion of economic rent the entire amount of income taxes. This somewhat overstates both the total economic rent and the federal government share. However, the federal tax advantages historically received by the oil and gas industry, including the depletion allowance and the ability to expense intangible drilling costs and other exploration costs, means that firms have paid lower income taxes on their oil and gas operations than on other activities at the competitive rate of return.

Approach

The intent of this chapter is not to replicate the historical accounting of revenues analyzed in Chapter II, but rather to understand how economic rent is generated and distributed under a variety of economic conditions in two different states, Alaska and Texas. For historical comparative purposes, we divide Alaska into three regions. These are the two producing regions, Cook Inlet and the North Slope, and a third region containing the rest of the state, including the federal OCS. We split Texas into two large divisions, onshore and offshore (including the federal OCS).

The purpose of the comparative analysis is to go beyond a simple accounting of the distribution of the economic rents estimated to have been received over approximately the past twenty years. We seek to understand what factors have principally been responsible for the observed pattern of size and distribution. To the extent possible, we would like to have quantitative estimates of their importance in explaining differences observed over time and among the regions.

We propose to analyze the contribution of the following five factors to the regional pattern of distribution. While these factors do not exhaust all influences on the generation and distribution of economic rent, we believe these are likely to

dominate all other factors. Foremost among these factors is geologic luck. Simply stated, accumulations of oil and gas are found in some regions and not in others. Even among producing regions, there is a wide variation in average productivity at any given point in time.

Another important factor is landowner luck. The state of Alaska was able to select the Prudhoe Bay area under its Statehood Act entitlement. In Texas, however, most production occurs on privately-owned lands. A third and fourth factor strongly affecting the size of regional economic rent are the prices of oil and gas and the extraction cost environment of the regions. Finally, lease terms and taxation, or more broadly, government policy toward the industry, may play a significant part. Regulation may increase costs as well, but we consider this as part of the cost environment for the purpose of the regional comparative analyses.

An important aspect of our approach is the use of a number of "counterfactual hypotheses" to help us analyze the historical picture. A test of a counterfactual hypothesis employs one or more assumptions known to be factually inaccurate in order to analyze how the outcome of a history might have depended upon that particular factor. It asks the question, "How might the actual historical pattern have differed if everything had been the same except for one or maybe two factors?"

Methodology

The methodology consists of a model, a set of data and base case assumptions to run the model, and a number of counterfactual hypotheses. We have developed a historical accounting model, HISTOIL, in order to define and tabulate the regional distribution of economic rent.

The accounting structure of the model follows exactly the flowchart of Figure 1. The model includes a cost, lease payment, and tax structure, and adds up discounted real cash flows from the beginning to the end year of simulation. Costs included in the accounting framework include all capital and operating costs for exploration and development of oil and gas fields. They do not include overhead costs for a central management headquarters. One should interpret financial results accordingly as the effects of an incremental investment in oil and gas exploration and development. Appendix D contains a complete description and documentation of the model HISTOIL.

As is the case with any accounting model, results using the model are a reflection of the data and assumptions put in to the model. We have analyzed available historical data on oil and gas exploration, development and operating costs from a large number of sources, including federal and state publications, special studies,

and private industry. Appendix B compiles and analyzes historical industry costs in Alaska. Appendix C examines the historical timing in Alaska between the beginning of exploration of an area, discovery of oil or gas, and commencement of commercial production. Specific assumptions regarding the actual values assumed for cost and timing parameters for the historical accounting analysis are included in Appendix D.

The counterfactual hypotheses we test examine directly address the five important factors enumerated above which determine regional size and distribution of petroleum economic rent. Once again, these are (1) geologic good fortune, (2) landownership boundaries, (3) price of oil and gas, (4) cost environment for industry operations, and (5) government policy. We are particularly concerned in this study with the fifth factor. How important have state tax structures and federal policy decisions been in explaining the size and distribution of economic rent as compared to geologic factors, landownership boundaries, and the price of oil? We address the relative contribution of these factors by estimating how the historical pattern observed for Alaska and Texas would have differed if one or more factors had not been the same.

In order to estimate what we consider to be the sensitivity of the historical pattern to the history of a particular factor, we make the assumption that the historical oil and gas production would not have changed in response to the new factors unless the scenario was obviously infeasible. Such an assumption is surely inaccurate, as changing conditions raising the profitability of oil and gas production would have stimulated production, and vice versa. But with this reasoning, we can say that our estimates of how the size of economic rent might have differed represent a lower bound estimate since they do not include the effect (which would be in the same direction) upon production.

Another problem with developing counterfactual assumptions comes with the treatment of bonus bids. These are fixed costs once acreage has been leased. However, firms would have altered their bids had they expected the altered historical pattern. There is no feasible way to re-estimate the total regional pattern of bonus bids under each new scenario, so we assume no change in bonus payments. In essence, this assumption means that the altered course of events, had it actually occurred, would have been unanticipated by industry. We display bonus bids and rental payments separately in our results so that the reader may view directly how this assumption might have affected the reported results.

We examine the hypothetical effects on the regional size and distribution of petroleum economic rent of seven separate counterfactual assumptions.

Public landownership: Unlike the Texas offshore region and the Alaska regions, in which essentially all production occurs on public lands, over 90 percent of onshore Texas production comes from private lands. We examine how distribution of economic rent might have differed in Texas if all oil and gas had been found on public lands. We assume a one-eighth royalty share on oil and gas and the same ratio of bonus and rental payments to total royalties each year as occurred on public lands. The hypothetical public lease payments calculated in this scenario also provide benchmark estimates for lease payments received historically from private landowners in Texas.¹

Price deregulation: This scenario assesses the effects of federal controls on oil and gas production. We assume removal by 1976 of price controls on natural gas, pricing all Texas production at the decontrolled intrastate market price. Oil wellhead prices for this scenario equal the average cost of imported oil from 1974 to 1980.²

Oil price freeze, 1976 levels: An alternative federal policy to either the early price deregulation scenario or to the actual course of events would be a continuation through 1982 of wellhead price controls, maintaining the average wellhead prices of oil and gas at the real 1976 price levels. For oil, this scenario might also be thought of as a counterfactual market assumption of no real market price increase since 1976.

Oil price freeze, 1971 levels: This scenario maintains real wellhead prices at the levels prevailing in 1971, before the assertion of market power by OPEC. This scenario is better thought of as a counterfactual market price hypothesis, since it would have been almost impossible for federal controls to keep the average price that low given the historical supply-demand relationships.

Regional economic parameters: The regional economic scenario involves replacing the market prices of oil and gas and certain of the cost parameters in one producing region with those which prevailed historically in another region. This provides an opportunity to test the degree to which the size and distribution of economic rent might depend upon the regional costs and distance from centers of market demand. We include only drilling costs and operating costs among the cost variables replaced in this scenario, so results of this case underestimate the total effect of regional cost differences.

Regional tax policy: There are essentially three tax regimes prevailing in the regions analyzed in this study. Petroleum production from lands within state jurisdiction in Alaska and Texas are subject to the respective state tax systems as well as federal Windfall Profits and corporate income taxation. Production from the federal OCS (a large portion of the Texas Offshore region) is

subject only to federal taxation. We examine how application of a tax system prevailing in another region would have affected the distribution of regional economic rent.

Regional tax policy with market and cost parameters: This is simply a combination of the two other scenarios, replacing the price and cost environment of one region and its tax structure with the market parameters and tax structure of another.

Generation and Distribution of Economic Rent--Base Case Results

Tables 25 and 26 show the tabulation of total petroleum economic rent and its distribution for Alaska's Cook Inlet and North Slope regions over approximately the past twenty years. Table 27 shows the summary for other Alaska, essentially a tabulation of industry expenditures for exploration which has so far been unsuccessful. Tables 28 and 29 present the analogous tabulation of economic rent and its distribution for offshore and onshore Texas, respectively. More detailed results of the base case simulation of the model HISTOIL for each of the five regions are contained in Appendix E, Tables E.1 through E.5.

Cook Inlet, Alaska: Table 25 shows that the cumulative economic rent from oil and gas development in Alaska's Cook Inlet region, discounted to 1982 and expressed in 1982 dollars, was around 12 billion dollars.³ This constitutes 56 percent of the total revenue over this period. During the 1970s, regional economic rent averaged \$200 million to \$300 million per year. After decontrol of domestic oil prices, the total economic rent shot upward to \$900 million in 1981, despite declining production.

Royalties and excise taxes took roughly 22 to 25 percent of the economic rent in the 1970s, but with the advent of the federal Windfall Profits tax this share rose to over 60 percent. Bonus and rental payments constituted a relatively small portion of the rent and were not significant at all after 1973, accounting for 7 percent of the cumulative discounted economic rent for the twenty-year period.

Partly because of low effective excise tax rates, Cook Inlet production has been highly profitable according to the figures in Table 25. Roughly equal flows of income taxes and the producers' (after-tax) share consistently averaged around \$100 million per year, or nearly 40 percent each of total economic rent. This pattern is not altered by using after-tax profits instead of after-tax economic rents. Economic rents in the accounting framework of Tables 25 through 29 treat investment expenditures as cash flows, while they are depreciated in nominal dollars for the profits definition. Using a 10 percent real discount rate, producers have received a cumulative value of \$4 billion in 1982 dollars, or 12.4 percent of total capital invested (including bonus and rental payments) in oil and gas exploration and development in the Cook Inlet region.

TABLE 25
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
COOK INLET 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
<u>CUMULATIVE, 1963-1971</u>	1730.7	561.6	261.1	112.4	69.1	119.0	143.1	0.116
1972.....	253.9	196.8	50.3	4.0	69.1	75.4	63.4	0.119
1973.....	281.3	214.2	51.8	27.1	74.1	61.2	91.4	0.122
1974.....	369.3	296.7	76.8	2.3	101.5	116.2	122.9	0.125
1975.....	412.9	324.3	79.8	1.2	113.5	129.8	139.1	0.127
1976.....	383.5	287.7	76.1	1.0	97.7	112.9	115.6	0.127
1977.....	357.0	273.3	73.2	0.7	94.8	104.6	93.2	0.127
1978.....	362.3	258.8	59.9	0.6	99.4	98.9	96.0	0.126
1979.....	371.3	261.7	56.7	0.5	103.4	101.1	94.3	0.126
1980.....	452.3	342.5	123.7	1.7	108.4	108.8	102.6	0.125
1981.....	1062.0	924.7	594.6	7.5	156.2	166.4	167.3	0.125
1982.....	885.0	723.4	467.4	4.6	113.8	137.5	146.6	0.124
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	22073.6	12382.3	4601.4	871.9	3211.4	3697.6	3940.4	0.124
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		12562.1		1392.4		3356.9		

SOURCE: OUTPUT FILE HISTOIL COOK BASECASE

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.L.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 0.1 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.

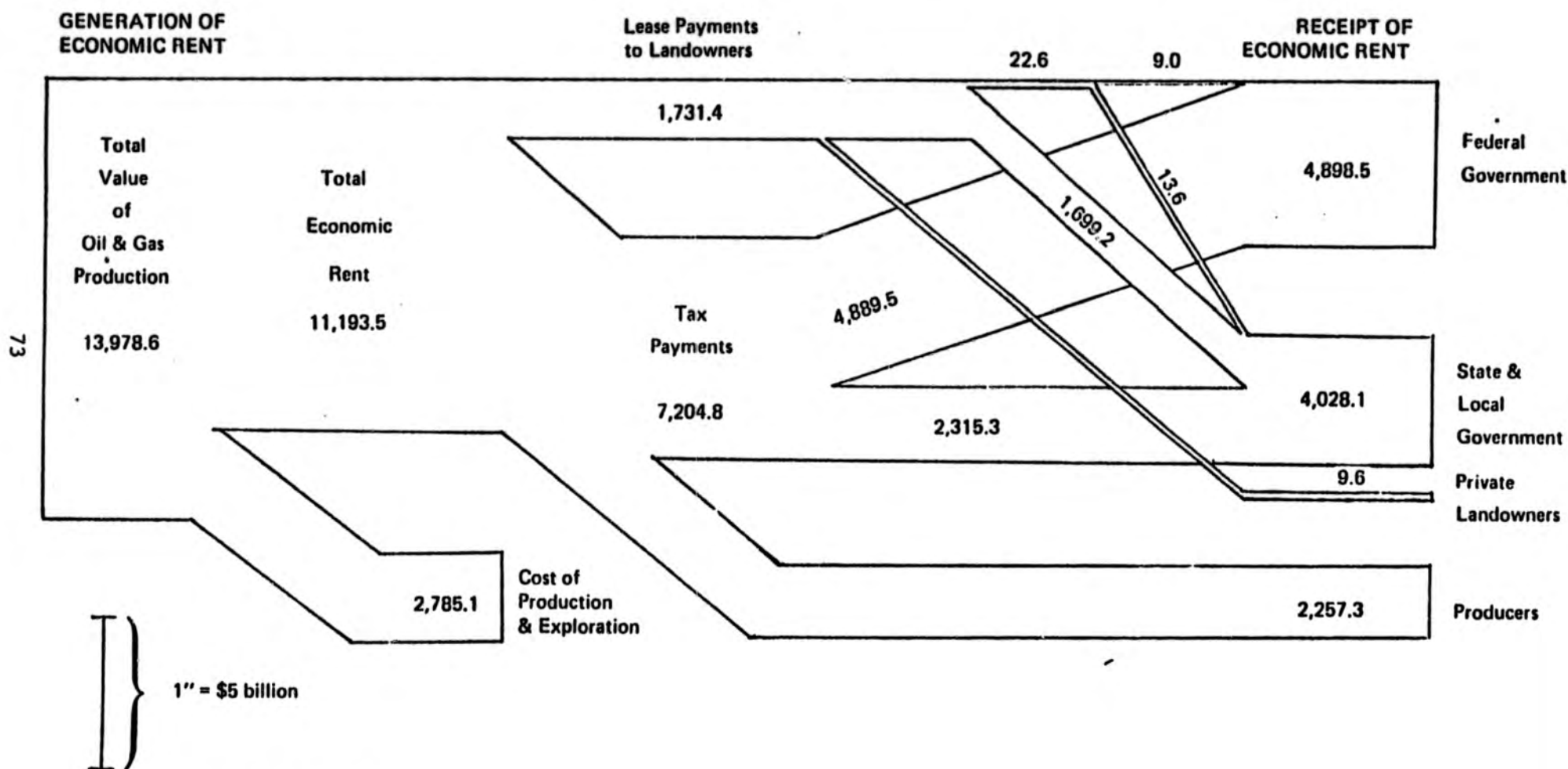
The Figure 2 flowchart illustrates the size and distribution of economic rent from petroleum development in all three regions of Alaska combined in 1981. Figure 3 summarizes the size and distribution of economic rent in the same year for the two Texas regions combined. This was the peak year for oil 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)

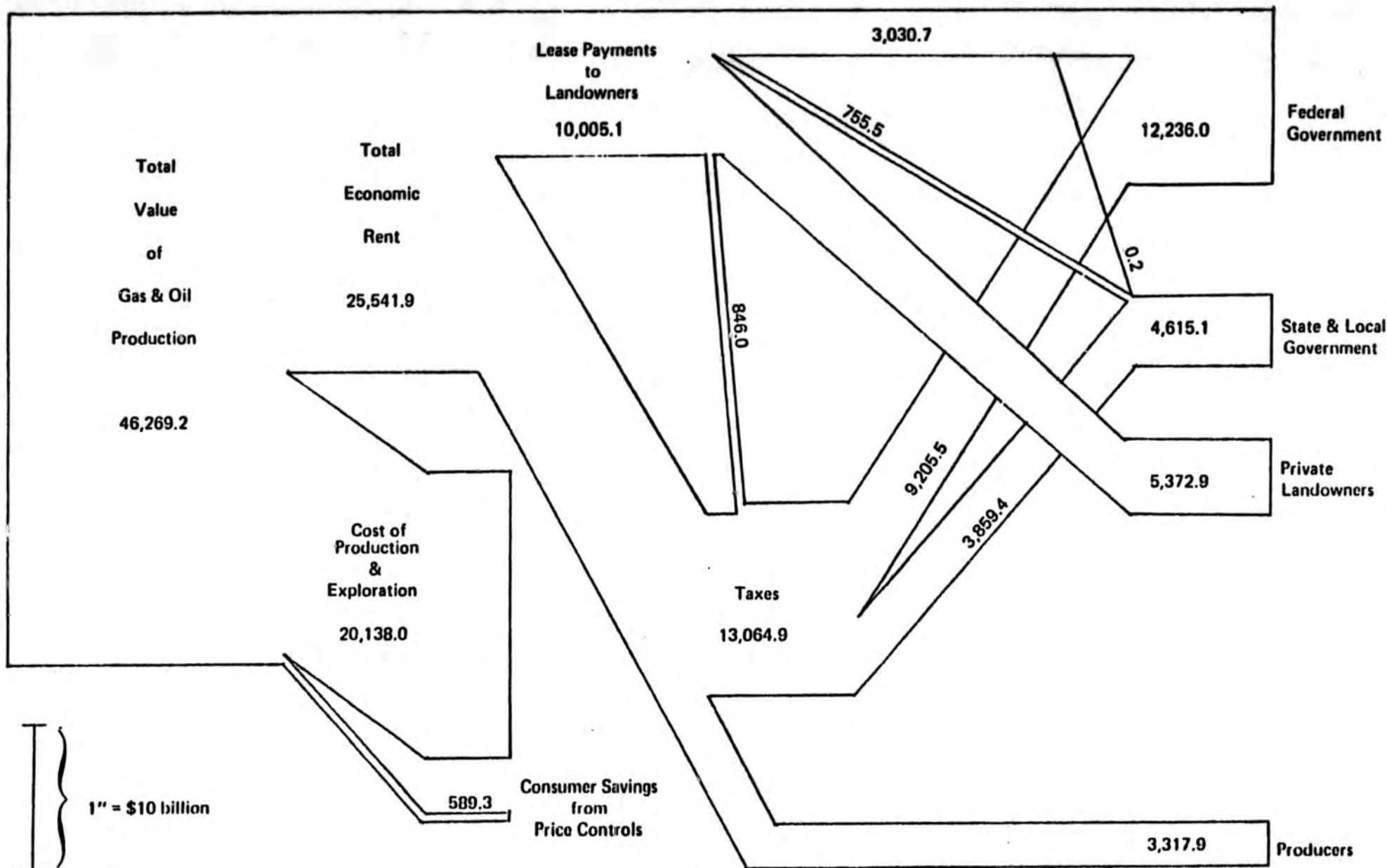


Source: Tables 11, 12, E.1, E.2, E.3.

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.

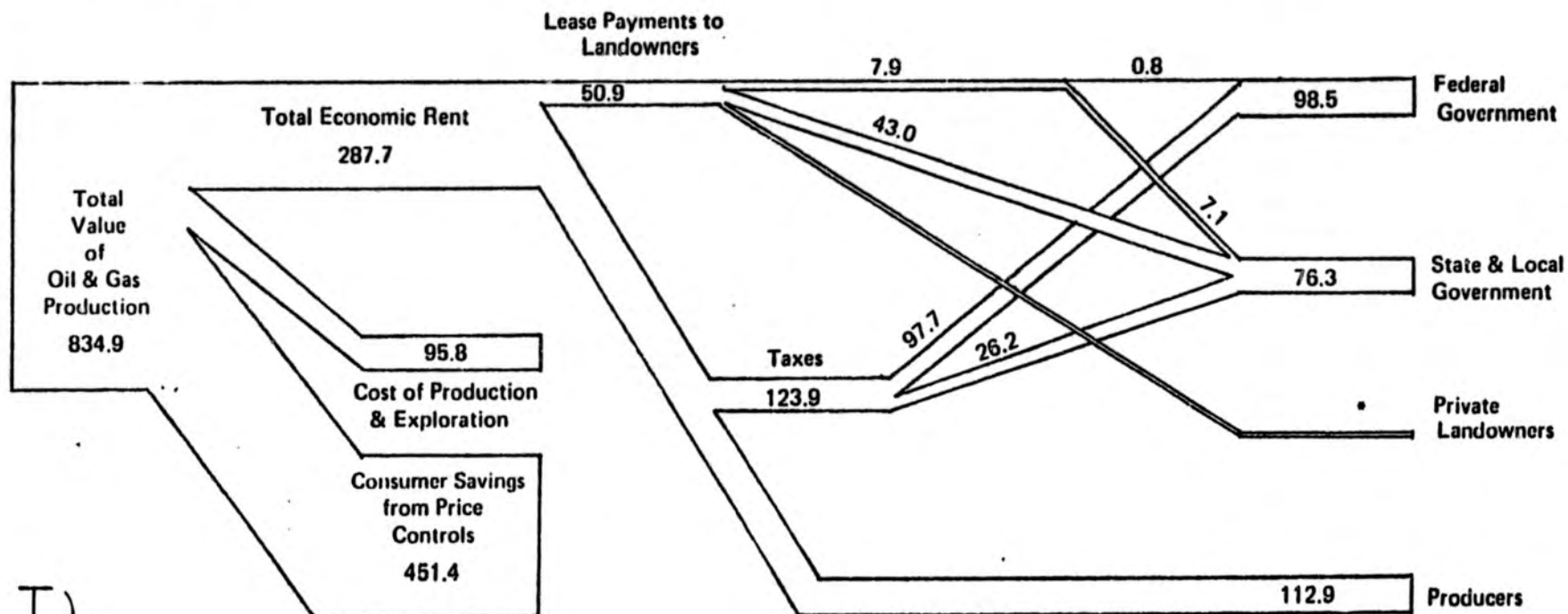
We may draw several conclusions from the comparative analysis of the size and distribution of petroleum economic rent in Alaska and Texas. The counterfactual scenarios provide the opportunity to examine quantitatively how important various factors are in explaining the pattern observed over time and 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



1" = \$500 million

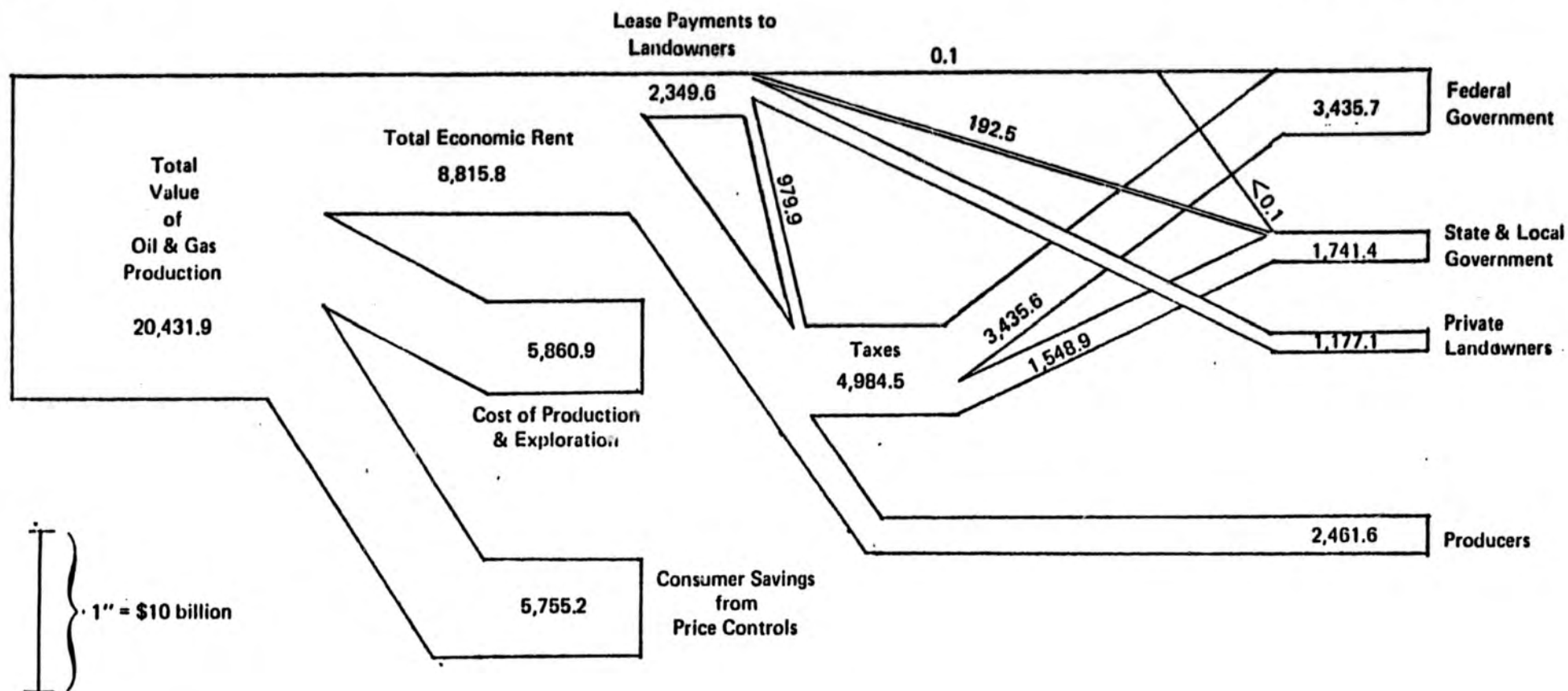
* = Negligible

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

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.

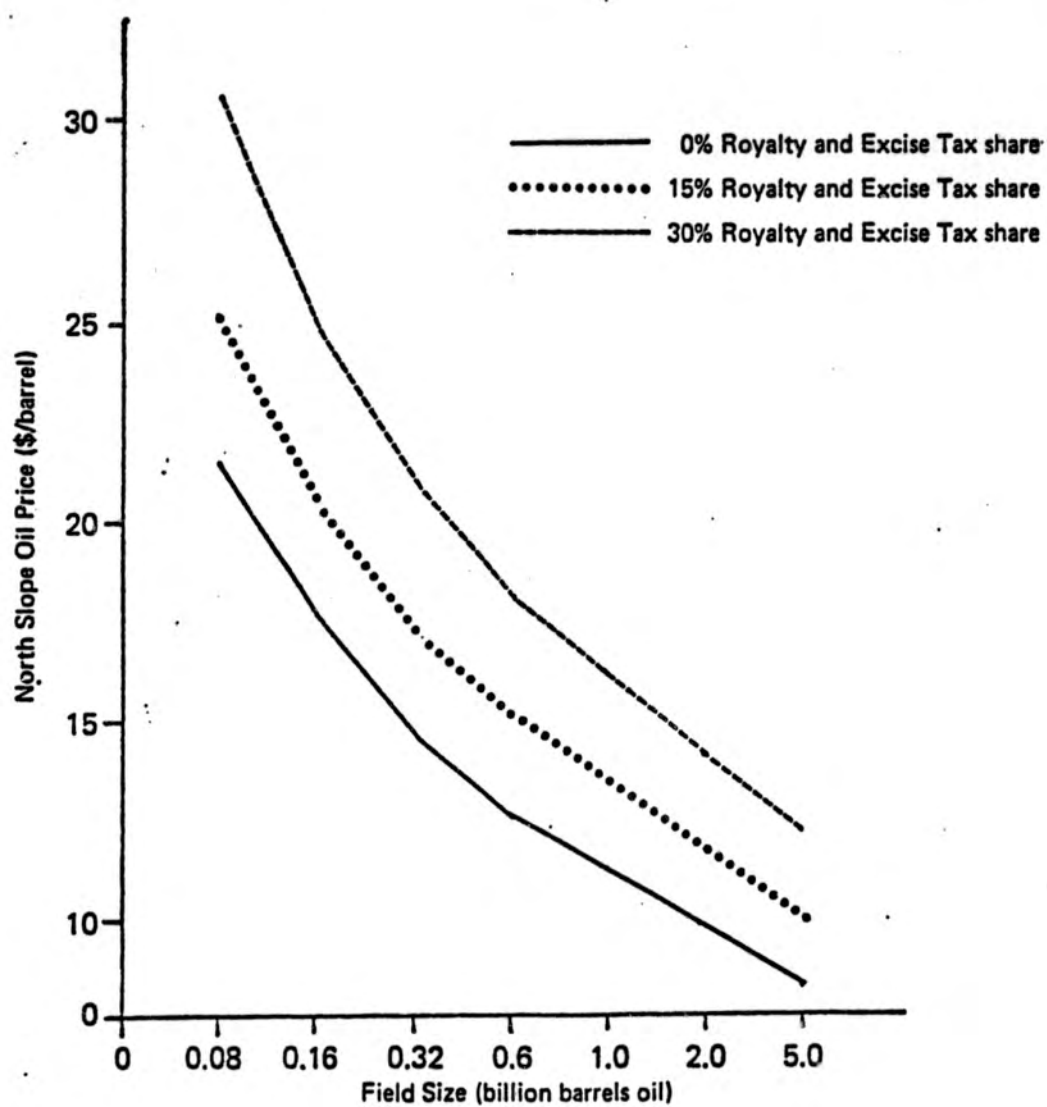
Figure 6 illustrates the effect of three alternative rates of royalty and excise taxation (excise shares) on the margin of development, applying the mid-range cost scenario to the simple model discussed here. The figure shows the margin as a tradeoff between the minimum size field that can be developed 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.

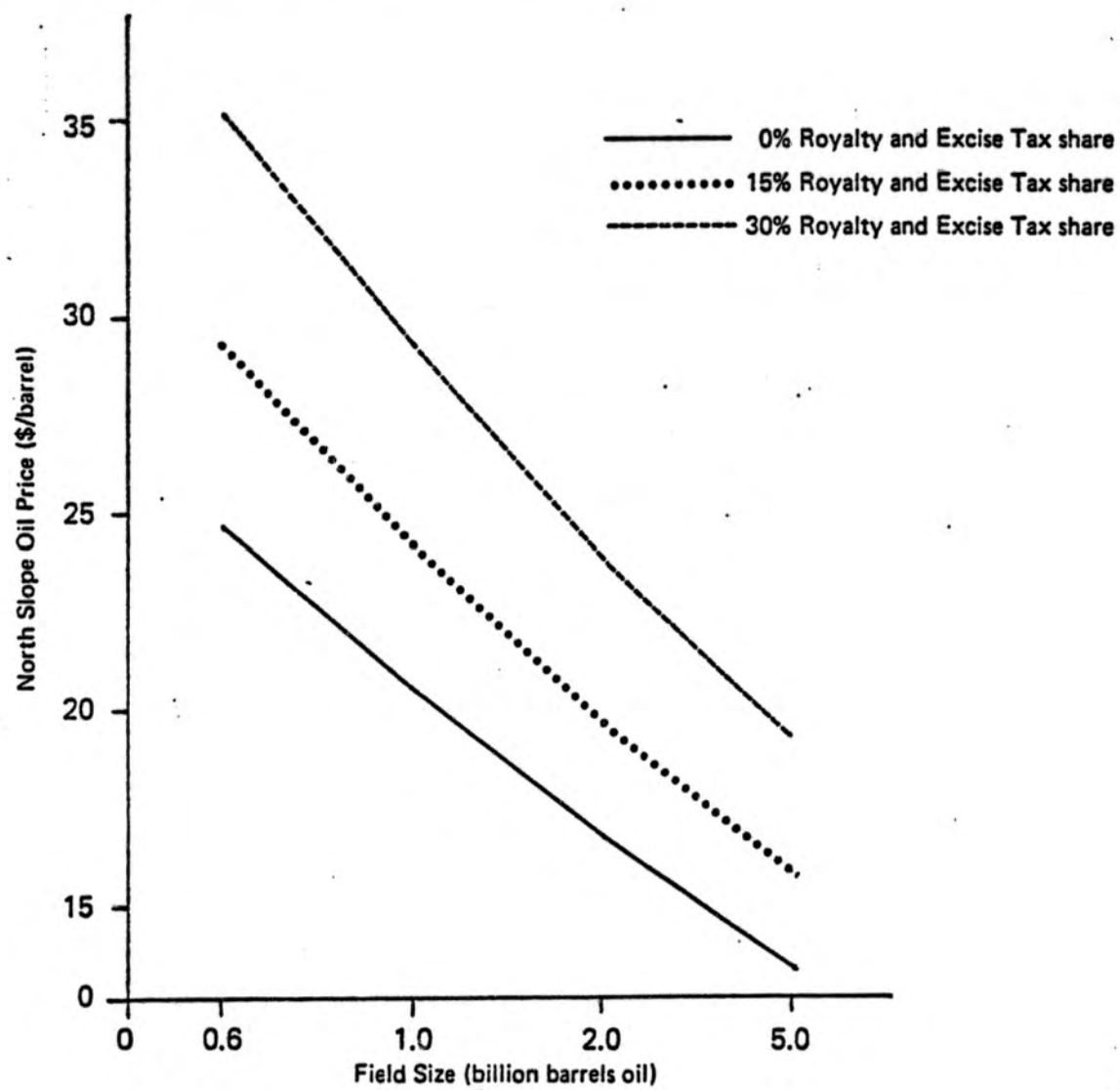
We do not show the comparable margin of production computed from the low cost scenario. Even for fields of less than ten million barrels, a 30 percent excise share allows profitable development at \$20 per barrel, and a \$25 price per barrel allows development with a 45 percent excise share. It is significant 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

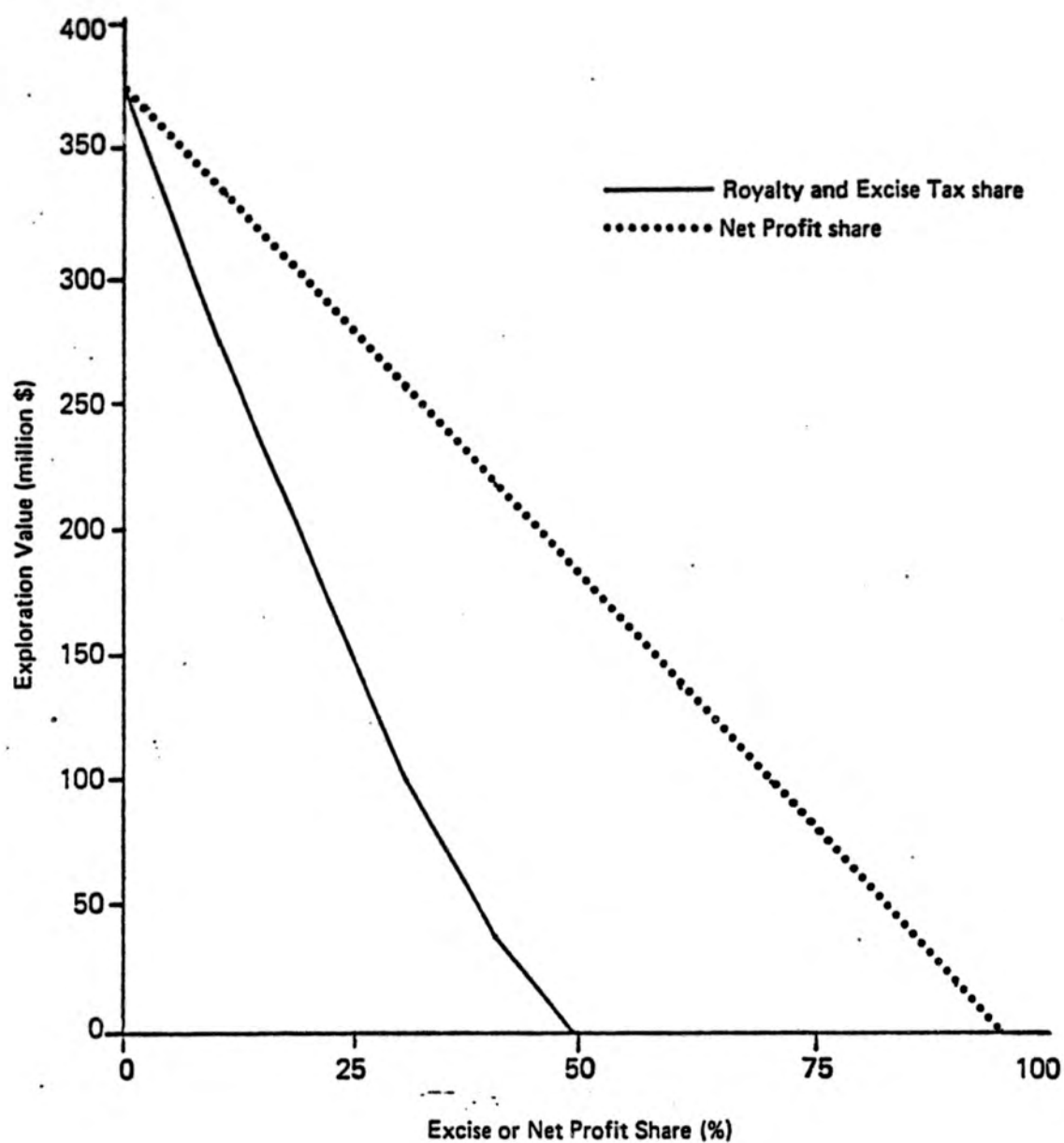
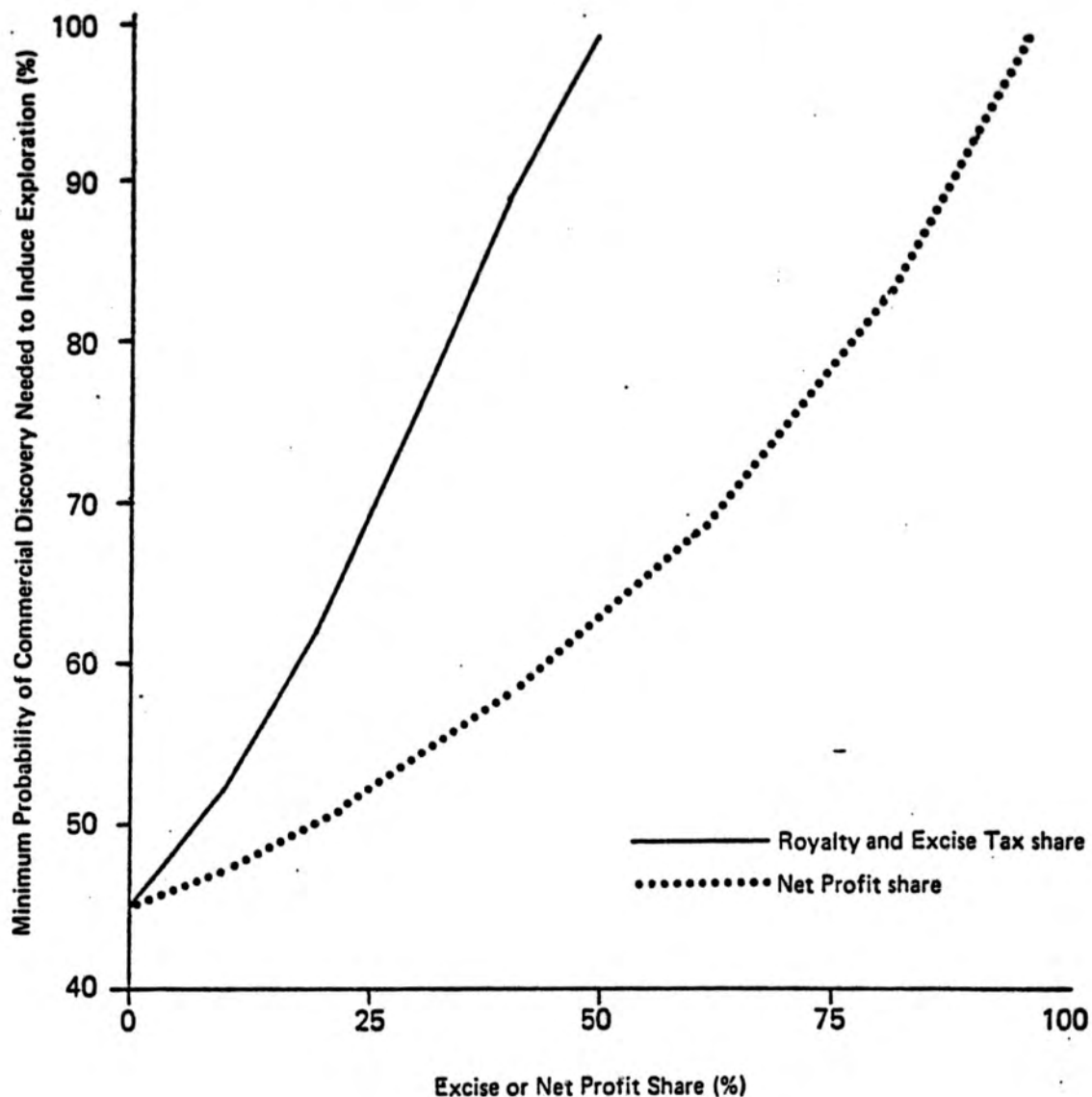


Figure 9. Effect of Royalty and Net Profit Shares on Margin of Exploration, Hypothetical Frontier Alaska Region



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

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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

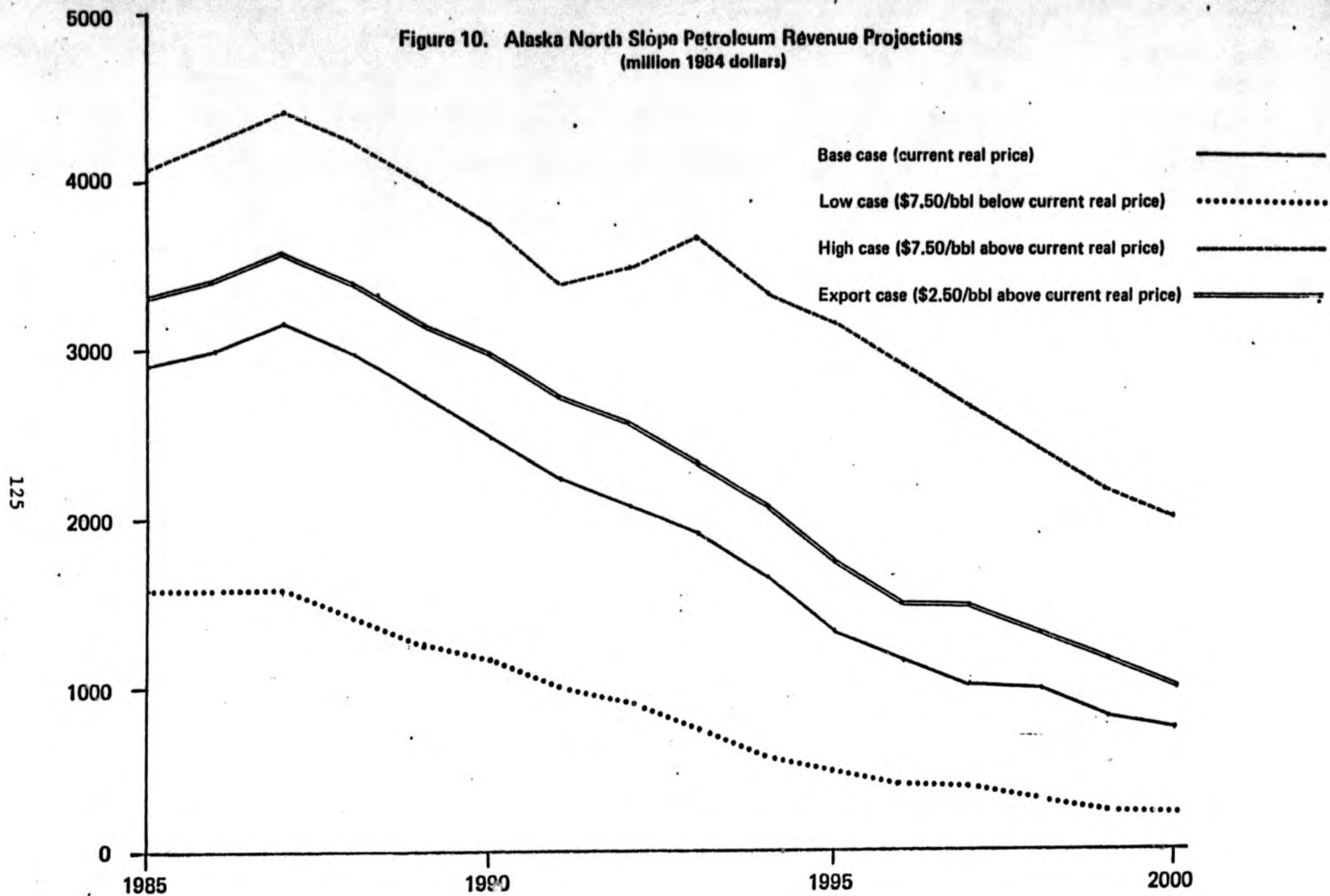
Summary and Discussion

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



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

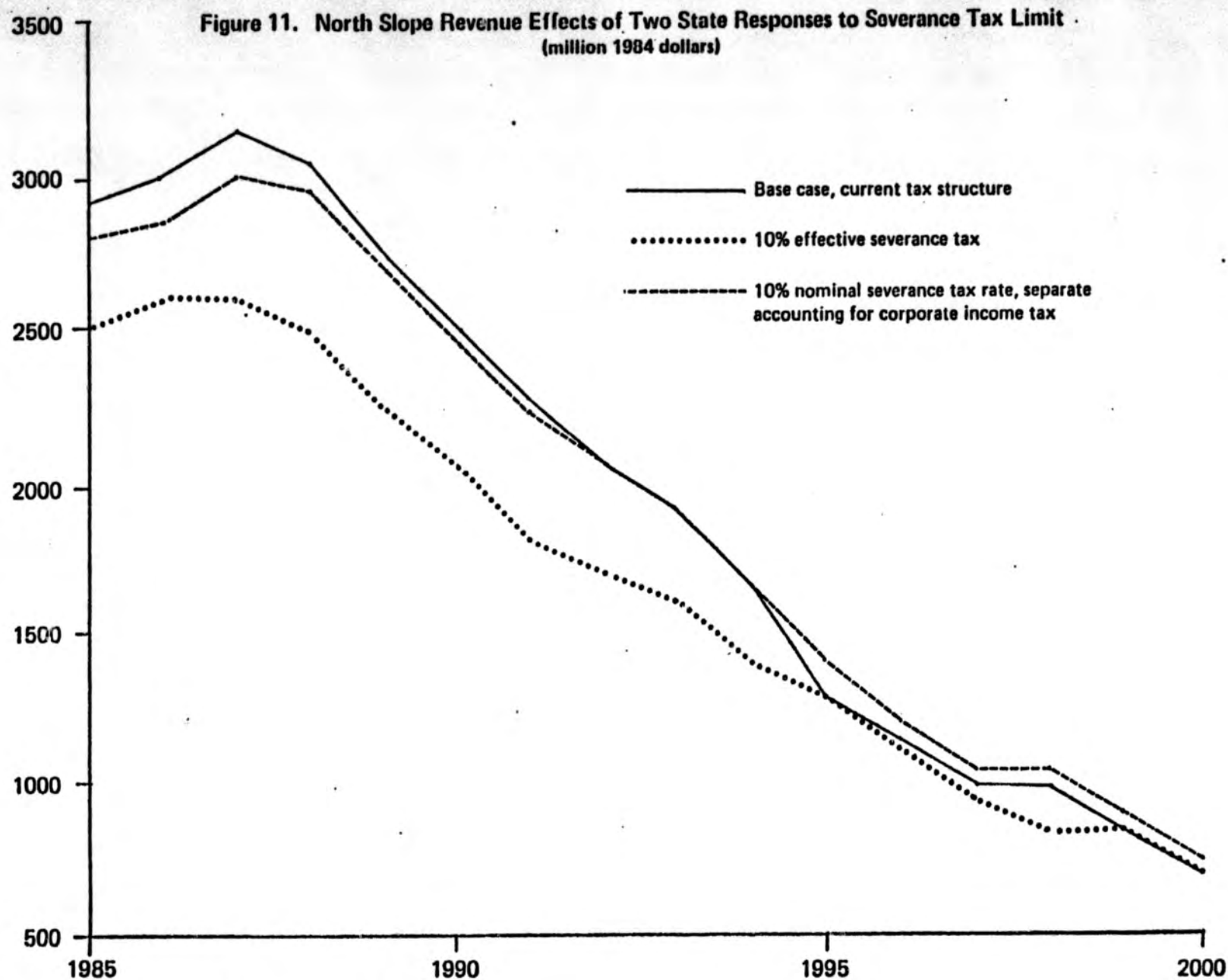
The results of the cumulative present values of oil development shown in Table 35 suggest a related observation about the structure of Alaska petroleum revenues. We have noted that known deposits of heavy oil on the North Slope near the Kuparuk field contain possibly over 40 billion barrels of oil in 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.

★

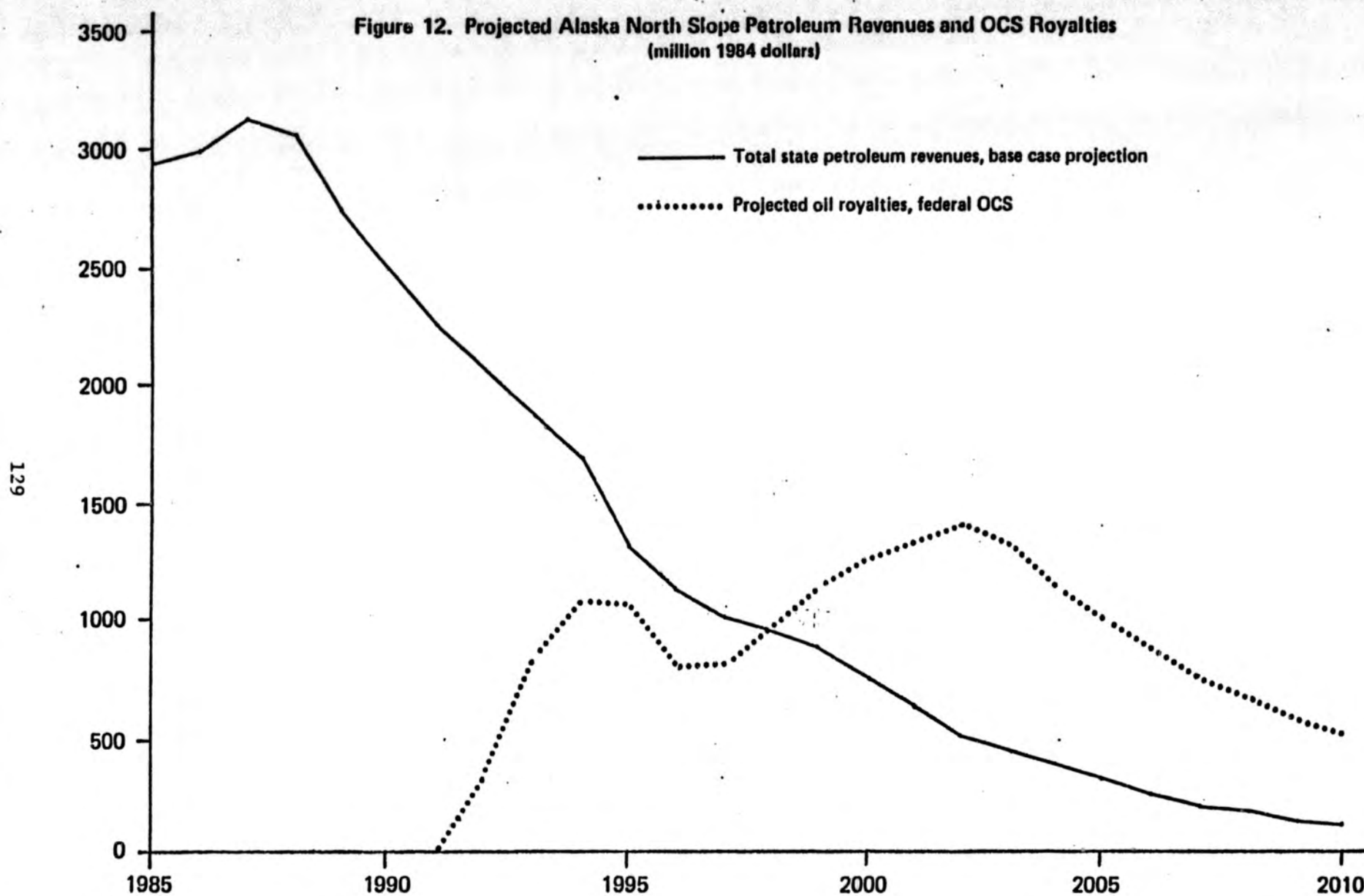
In all the scenarios we examined in this chapter, North Slope oil production declined steadily in the 1990s despite the addition of a number of large new fields. This mainly results from the huge size of current production from Prudhoe Bay, but also because new production added over the next eight years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



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

The base for calculating a state's share of timber receipts, the largest portion of national forest receipts, was gross receipts less deductions for reforestation fees and the costs of access roads constructed by timber purchasers. In 1976, Congress amended the National Forest Revenue Act to base the state's share on the gross sales value alone, thus increasing the amount states receive by 25 percent of the road and reforestation costs.²¹

Mineral Leasing Act of 1920. When the withdrawal of the national forest system from the public domain was largely complete, the focus of the conservation movement extended to mineral-bearing public lands, especially those containing coal and oil. Again, largely eastern conservation interests supported withdrawing these lands from entry and disposal, and extractive industries and other development interests in western states opposed them.

The Mineral Leasing Act of 1920²² was a compromise between these interests. While the law provided that mineral-bearing public domain lands would remain in federal ownership, private interests could lease development rights to these lands. The states containing leased federal mineral lands would receive a share of the mineral lease receipts, including bonus payments, rents, and royalties on production. That is, the Mineral Leasing Act, like the National Forest Revenue Act, shared the value of the federal proprietary interest with the states.²³

The public debate about mineral resource revenue sharing, like that for national forest revenues, was phrased in terms of compensation for state property tax revenue losses. As put by Representative Mondell in 1919:

. . . There should be no difference of opinion as to the rights of the States and their communities to be compensated for the great losses in taxing value which they will suffer by reason of holding perpetually in Federal ownership untaxed very great areas of land that will in time support large populations and require great outlay for the support of the institution of government. The only question that ever ought to be raised in this connection is as to what portion of the rents and royalties that will be received by the Government are necessary to compensate the States and their communities for their loss in taxing value.²⁴

However, the sharing of the proprietary values of public lands is compensation to the states as well for the continued imposition of federal ownership and management of lands affecting the state and local governments and their constituents. Indeed, it is no accident that federal legislation sharing resource receipts from public lands coincide with federal initiatives to retain valuable resources in federal ownership and control.

When enacted, the Mineral Leasing Act of 1920 provided that states would receive 37-1/2 percent of lease revenues from leased lands within their boundaries. This figure was arbitrary in that it was not based on any empirical evidence of the amount of local tax losses. Rather, it was a compromise between the 30 percent share of lease revenues in the House version and 45 percent share in the Senate bill. Both versions started with the 25 percent share states receive under the National Forest Revenue Act, increasing it to account for the additional benefits the states received from federal funds appropriated for building national forest roads.²⁵

Of the remaining lease revenues, the act provided that 52-1/2 percent be deposited in the Reclamation Fund for irrigation development in certain western states, a similar compromise between 60 percent and 45 percent proposed in the bills as introduced in the House and Senate, respectively. Although Congress continued in this act to restrict the use of shared resource revenues to roads and schools, states did not have to distribute the funds to county governments containing the leased lands, a departure from provisions in the National Forest Revenue Act.

Congress did not extend the provisions of the Mineral Leasing Act of 1920 to public domain lands in the Alaska Territory until 1947.²⁶ In 1957, however, the act was amended to provide that Alaska, still a territory, receive an additional 52-1/2 percent of mineral lease revenues, for a total share of 90 percent. The initial purpose stated for giving Alaska a larger share was to equalize its treatment with respect to other western states that received additional benefits from the Reclamation Fund, which Congress declined to extend to Alaska. Instead, Congress gave the funds directly to the territorial government to encourage it to accept more responsibility for conducting internal improvements and programs.²⁷ The legislature was permitted to use the additional 52-1/2 percent share of mineral lease receipts as the legislature directed, although the standard 37-1/2 percent still had to be used to support public schools and roads.

In 1975, Congress amended the Mineral Leasing Act to increase the share of lease revenues that all states (except Alaska) receive from 37-1/2 percent to 50 percent.²⁸ In addition to schools and roads, permissible uses of the additional 12-1/2 percent included planning, building and maintaining public utilities, and providing public services. In spending the additional shared resource revenues, Congress required states to give priority to localities experiencing social or economic impacts from development of leased lands.

A year later, Congress dropped the use restrictions for all shared receipts under the Mineral Leasing Act of 1920.²⁹ States are now required only to give priority in spending these funds to areas affected by the development of minerals leased under the act.

The Mineral Leasing Act of 1920 does not apply to all federal mineral bearing lands, but only to public domain lands, including any in the national forests. It does not apply to acquired lands or to national parks and monuments; naval petroleum and oil shale reserves; or federal lands within incorporated cities, towns, and villages.

Federal Water Power Act. The Federal Water Power Act³⁰ was enacted in 1920 to provide for orderly development of the nation's waterways, both for hydroelectric power and for navigation. It was the outcome of a decade of controversy over the use and development of waterways which, prior to this law's enactment, were undertaken in an uncoordinated and chaotic manner.³¹ There was also some concern that a few large corporations might gain control of hydroelectric power development.

The Federal Water Power Act authorized the Federal Power Commission to issue licenses for navigational improvements and hydroelectric power generation and transmission on public lands and in national forests. It also provides that states in which the development is located receive 37-1/2 percent of the license receipts after certain administrative costs are deducted. The rationale for this provision is not explained in the legislative reports on it, but it is consistent with the resource revenue sharing provisions of the Mineral Leasing Act, passed in the same year, except that no restrictions were placed on use of the funds.

Taylor Grazing Act. The public lands of the western states were historically considered free and open. This notion received judicial sanction in 1896 by the U.S. Supreme Court, which said that the right to graze cattle on the public lands resulted from "implied license, growing out of custom of nearly a hundred years."³² The Court at that time indicated, however, that legislation closing these lands would, in effect, revoke this implied right. Passage of legislation to protect the arid public grasslands of the western states proved a difficult task; the federal government did not attempt to exercise widespread control over grazing on the public domain until Congress passed the Taylor Grazing Act in 1934.³³

The Taylor Grazing Act authorized the Secretary of the Interior to establish grazing districts on the public domain and to charge a reasonable fee for the use of forage. It also authorized the Secretary to lease isolated and disconnected tracts outside grazing districts. Half of the grazing fee receipts from both types of land were to be distributed to the states to use for the benefit of the counties containing the land, subject to Congressional appropriation.³⁴ The exception to this rule was that 25 percent of fees collected from grazing districts on Indian lands that had been ceded to the United States was to be shared with the states. These funds had to be used for public schools and roads in the counties in which these lands were situated.

The basis for the 50 percent figure is not entirely explained in the record. A predecessor to the Taylor Act contained a provision for distributing 25 percent of grazing fee receipts to the states, based on the national forest precedent. No explanation for the added 25 percent is given, other than assertions that 25 percent was not enough.³⁵

Major changes in the Taylor Act resource revenue sharing provisions were made in 1947.³⁶ Grazing fees were divided into two components: a range improvement fee and a grazing fee proper, the latter of which only was to be shared with the states. In addition, the percentage shared from grazing districts and districts on ceded Indian lands was changed. States now receive 12-1/2 percent of fees from grazing districts (down from 50 percent) and 33-1/3 percent from fees from districts on ceded Indian lands (up from 25 percent). No change was made in the percentage of fees shared from land outside the districts; states continue to receive 50 percent.

The 1947 amendments were intended to bring into the federal treasury sufficient funds to pay for the costs of range administration, which were not met under the original system of distributing the grazing receipts. Peffer indicates that the changes were made as a tradeoff against increased grazing fees.³⁷ Congress provided that the states give up a portion of the funds so that ranchers would not pay higher fees for forage on public domain lands.

The Taylor Grazing Act applies to the unreserved and unappropriated public domain; therefore, it does not apply to national forests, national parks and monuments, Indian reservations, and certain other lands, including all acquired lands. The resource revenue sharing provisions apply only to grazing fee receipts; other sources of revenue from these lands may not be subject to sharing provisions at all, such as special-use permit fees, or may be shared under different laws, such as mineral lease bonuses, rents, and royalties.³⁸

The Taylor Grazing Act never applied to the public domain in Alaska. Seven years before it was passed, Congress enacted the Alaska Grazing Act,³⁹ which established grazing districts and fees and which provides for Alaska to receive that portion of grazing fees that exceeds the cost of administration. It is doubtful that Alaska ever received any payments from grazing lands; if it did, the state would be required to use the funds for public education and roads.

National Petroleum Reserve in Alaska. The Naval Petroleum Reserves Production Act of 1976 redesignated the Naval Petroleum Reserve Numbered 4, Alaska, as the "National Petroleum Reserve in Alaska," transferring its administration to the Interior

Department.⁴⁰ This act contained a provision authorizing the Secretary of the Interior to assist local governments in meeting the costs of increased municipal services and facilities if the Secretary determined that communities located on or near the reserve experienced substantial increases in the need for municipal services as a direct result of mineral exploration on the reserve and if the communities would be unfairly and excessively burdened in meeting those needs.⁴¹

Congress replaced this provision four years later in an appropriations act for the Department of the Interior.⁴² Currently, Alaska receives 50 percent of all receipts from oil and gas lease sales, rentals, bonuses, and royalties on the National Petroleum Reserve in Alaska (NPR-A). The state may use these funds for planning; for building, maintaining, and operating essential public facilities; and for other necessary public services, giving priority to those areas most affected by the oil and gas development activities on NPR-A.⁴³ The statute does not require the state to distribute any NPR-A funds to local governments.

Resource Revenues from Federal Acquired Lands

In 1941, the U.S. Attorney General issued an opinion that the Mineral Leasing Act of 1920 did not apply to all federal lands, but only to the public domain. Congress had granted authority for federal agencies to lease mineral rights on certain acquired lands even before passage of the Mineral Leasing Act of 1920, including authority for the Forest Service to lease national forest lands acquired under the 1911 Weeks Act. In 1946, the Truman administration transferred mineral leasing programs on national forest lands to the Secretary of the Interior, who moved to consolidate the authority for granting leases on acquired lands under one law, with specific exceptions.⁴⁴

Mineral Leasing Act for Acquired Lands. The 1947 acquired lands leasing law provides that all receipts from mineral leases on acquired lands be distributed in the same manner as prescribed for other receipts from the same lands.⁴⁵ Twenty-five percent of mineral lease revenues on acquired national forest lands, for example, are shared with states containing the lands that generate the funds and are subject to the same use restrictions as other forest-generated resource revenues. (Mineral lease revenues on public domain national forest lands, on the other hand, are governed by the Mineral Leasing Act of 1920.) The Congressional reports on this legislation do not explain the rationale for the revenue-sharing provision; presumably it derives from an attempt not to upset the political compromise achieved with the previous laws. The Mineral Leasing Act for Acquired Lands does not apply to lands acquired for national parks and monuments, which are not intended to be revenue-producing, nor to acquired tidelands and submerged lands.⁴⁶

Bankhead-Jones Farm Tenant Act. In 1937, during the Great Depression, Congress authorized the purchase of what were termed submarginal agricultural lands. These lands, located primarily in western states, produced good crops in years with unusually high rainfall, but no crops in even a slight drought. Congress hoped that federal management of these lands would correct maladjustments in land use and control soil erosion as well as aid the families that could not make a reasonable living on them.⁴⁷ These lands eventually became the National Grasslands, part of the National Forest System. Some 2.3 million acres were acquired under the Bankhead-Jones Act, constituting the largest category of acquired lands.⁴⁸

Counties containing Bankhead-Jones lands receive 25 percent of net resource revenues the federal government receives from them and must use the funds to support schools or roads.⁴⁹ The shared revenues include grazing fees and mineral leases, for example, but do not include any receipts from sale of these lands, for which states receive the portion specified in their statehood acts. The 1937 Bankhead-Jones Act succeeded legislation enacted in 1933 to accomplish the same purpose but which did not include provisions to share resource revenues with state and local governments. Congress used the National Forest Revenue Act as a model, with the difference that the compensating payments are made directly to counties, not to states.⁵⁰ Since Bankhead-Jones program focused on resource-poor, marginal lands, the total property values available to share with local governments have been small.

Army Corps of Engineers Flood Control Lands. In 1941, Congress authorized the acquisition of lands for a number of river and flood control projects, to be managed by the Army Corps of Engineers.⁵¹ The statute also authorized payments to states of 25 percent of the revenues from leases of the land acquired for flood control purposes. States must spend the payments on schools and roads in the counties containing the leased lands and for other county government expenses. In 1946, Congress decided that the 25 percent share did not adequately compensate communities for taxes lost through federal land acquisition, and increased the states' share threefold, to 75 percent.⁵²

Administering Resource Revenue Sharing

Some programs specify that administrative costs are subtracted from gross revenues before the sharing percentage is applied. Statutes that explicitly provide for basing state or local payments on net receipts include the Bankhead-Jones Act, the Migratory Bird Conservation Act, the Alaska Grazing Act, the Geothermal Steam Act, and the Federal Water Power Act. Administrative or other costs may be deducted from other receipts even if the statute is silent on the subject. The Forest Service, for example, deducted reforestation

and access road costs from gross receipts before calculating the state share under the National Forest Revenue Act until 1976, when Congress prohibited this practice.

Administrative costs are not deducted from gross receipts in sharing revenues from mineral leases on federal lands. The 1980 legislation creating the Windfall Profit Tax on Crude Oil, however, specifies that the tax is subtracted from federal royalty payments before states' shares are calculated. This significantly reduces the state share of revenues from federal oil leases. In Alaska, the Windfall Profit Tax deduction affects the state share of royalties from the Swanson River and Beaver Creek oil fields on the Kenai Peninsula.

Congress has recently moved to eliminate restrictions on the use of shared resource revenues; however, almost all of the statutes contained such restrictions at one time. During the early days of the new nation and in settling the western states, it made sense to foster construction of schools and roads for the expanding population. Restricted use predominated until 1981, after the use restrictions were removed for payments under the Mineral Leasing Act of 1920.

Alaska has occasionally been singled out for special treatment under these laws. Probably the most significant example is its 90 percent share of mineral lease revenues on most public domain lands. In this case, the state government has received a larger portion of lease receipts than that received by other states because it does not benefit from certain federal programs that are financed, in part, by federal mineral lease revenues. The state receives 50 percent of oil and gas lease receipts on the National Petroleum Reserve Alaska, the same share in this case as other states receive from oil and gas revenues under the Mineral Leasing Act of 1920.

Problems with Resource Revenue Sharing

Public lands that do not produce resource development revenues or user fees do not provide states and localities with any revenues. Lands may generate little or no receipts for several reasons. They may merely be resource-poor lands, for instance, or they may produce little revenue due to federal management policies or economic conditions. For whatever reason they exist, the differences in the levels of resource receipts shared with state and local governments have given rise to numerous complaints.

The fact that certain lands produce little or no revenues does not necessarily indicate that their presence imposes few burdens on localities. Certain public lands--national parks and wilderness areas, for example--are prohibited by law from supporting most revenue-generating activities. These areas may attract many visitors to an area, generating revenues primarily for the state,

not local, governments through income and sales taxes. It is the local government, however, that must provide for law enforcement, road maintenance, hospitals, and other services related directly and indirectly to the activities on these lands.

In general, it is likely that the total of payments made to local governments under resource revenue sharing provisions seldom equals either (1) the level of property tax revenues they would collect were the lands privately owned, or (2) the level of expenditures they make to support the activities on both federal and private lands which have been generated by federal land management.

Another problem for local governments lies in the ad hoc nature of the revenue sharing laws that have been enacted since 1906. The share allocated to states and localities varies widely, from 5 to 90 percent, based on whatever was the necessary political compromise of the day. As a result, the same type of activity may provide very different levels of state and local receipts on adjacent lands. Mineral leasing on public domain and acquired lands in national forests is a case in point; in the former circumstance, the state/local share is generally 50 percent while in the latter, it is one-half as much.

Several additional problems with resource revenue sharing statutes exist. One problem is that state and local governments have been unable to budget these funds with any degree of certainty. Management decisions over which they have no control may quite suddenly reduce or eliminate revenue-generating activities, or economic conditions may cause resource revenues to vary inversely with revenue needs. Statutory restrictions on the use of shared revenues may pose problems in some cases, while insufficient requirements for distributing the shared funds to localities affected by federal land management may cause hardship in others.

Finally, resource revenue sharing suffers from an inherent defect as a mechanism of obtaining local support for federal conservation or preservation efforts. Tying payments to revenue generation almost requires local governments to oppose major federal land purchases for national parks, wildlife refuges, and wilderness areas due to the inevitable fiscal pressures of a diminished property tax base.

Payments in Lieu of Taxes for Public Lands

Payments in lieu of taxes (PILOT) and resource revenue sharing payments constitute different approaches to solving the same problem, that of obtaining local support for national land and resource management objectives. The general approach of PILOT programs is to reimburse local governments for the amount of tax revenues foregone due to the presence of tax-exempt federal property. This ideal is approximated with varying success in

practice, however. Many specific PILOT programs apply to lands originally subject to taxation which were subsequently purchased by the federal government for conservation or preservation uses, causing measurable tax losses.

Historical Precedents for Payments in Lieu of Taxes

Until recently, PILOT laws have all applied to comparatively limited acreage, usually in connection with a specific federal development project. These payments are usually made directly to affected local governments, not to states, and are less often restricted to specified uses than resource revenue sharing payments. Some PILOT provisions, in fact, began as revenue sharing measures that were changed to provide more revenues for local governments. Some combine elements of both types of payments. This section describes the payments in lieu of taxes on public lands enacted since 1916, eight years after the first revenue sharing program was instituted.

Oregon and California Railroad and Coos Bay Wagon Road Grant Lands. The first payment in lieu of tax statutes applied to two transportation system land grants of heavily-timbered lands in western Oregon. The federal government repossessed the Oregon and California Railroad (O&C) and Coos Bay Wagon Road (CBWR) Grant Lands in 1916 and 1919, respectively, when the private grantees failed to follow the grant stipulations. Since portions of these lands had yielded local property tax revenues, the federal government agreed to reimburse the counties containing them for the tax losses. Congress required, however, that these payments must come from revenues actually generated by these lands.

The original intention was to sell the repossessed O&C lands to private parties, with a portion of the proceeds distributed to the counties and states. The sales proceeded slowly, however, and in 1926 Congress adopted a scheme for annual payments in lieu of taxes, appropriating a lump sum to pay back taxes to the counties.⁵³ The counties received very little under the PILOT provision, however, due to a 1928 decision of the Comptroller General that these payments also had to come from proceeds from sale of the lands. As a result, Congress occasionally had to appropriate funds to make the payments in lieu of taxes. This led Congress in 1937 to replace the PILOT program with a resource revenue sharing one, giving the counties 50 percent of all receipts realized from the O&C lands.⁵⁴ Under the 1937 amendment, timber sales on the lands replaced sales of the lands themselves as the main source of the shared receipts. Clawson and Held report that Congress favored the change from payments in lieu of taxes to sharing of receipts because it was expected to yield less revenue for the counties.⁵⁵ No use restrictions exist for these payments.

The Coos Bay Wagon Road lands have a different history. Congress originally adopted revenue sharing as the manner of making payments to the counties for the repossessed lands, but changed this to a payment in lieu of taxes in 1939.⁵⁶ Under the PILOT scheme, the counties receive payments computed "by applying the same rates of taxation as are applied to privately owned property of similar character in such counties" to the assessed value of the land and the timber upon it.⁵⁷ An upper limit is placed upon these payments; they may not exceed 75 percent of the receipts generated by these lands. The law provides for periodic reappraisals of the property so that the federal payments reflect trends in the value of, and taxes paid on, similar private holdings.⁵⁸

Boulder Canyon Project. The 1928 Boulder Canyon Project Act authorized construction of the Hoover Dam and other related works on the Colorado River. This project provides another case, like the Coos Bay Wagon Road lands, of a revenue sharing measure being changed to a payment in lieu of taxes. The legislation originally provided that Arizona and Nevada each receive 18.75 percent of "excess revenues" from the project for a total distributed share equal to 37.5 percent.⁵⁹ The 37.5 percent figure is the same as in the Federal Water Power Act of 1920, and was intended to compensate the states for the revenues they would have collected had the dam and related works been privately built and operated.⁶⁰

The "excess revenues" this percentage applied to were those receipts from charges to power purchasers over and above the amortization payments for the dam. In 1929, however, the U.S. Attorney General ruled that the project was not required to produce excess revenues. Taking this ruling into account and the possibility of downward adjustments in power rates, the states agreed to accept annual flat sum payments. Congress amended the payment schedule in 1940 to a flat sum of \$300,000 (net of any taxes collected from the project by either state or its political subdivisions), paid to each of these states annually until 1987.⁶¹ The statute identifies these payments as "contractual obligations of the United States, requiring that the rates charged for power be high enough to ensure the \$300,000 annual payment to each state."⁶² There are no restrictions on the use of these funds.

Tennessee Valley Authority. The 1933 legislation establishing the Tennessee Valley Authority (TVA) included a revenue sharing provision granting 5 percent of gross proceeds from the sale of power (excluding that used by federal agencies) to the states in which TVA hydroelectric plants were situated.⁶³ At the time, the statute applied only to Alabama and Tennessee. In the late 1930s, however, TVA acquired a number of private rural utility companies with which it competed.⁶⁴ Counties in the vicinity had derived a substantial portion of their revenues from property taxes on these utilities. Without this income, they faced the prospect of

defaulting on bonds and the inability to operate county schools. The constitution for the state of Tennessee did not permit the state to distribute its TVA shared revenue payments to affected counties.

In 1940, Congress adopted a new system for calculating and distributing tax-loss compensatory payments. This system includes two sets of payments and is somewhat complicated. First, TVA pays the counties a sum equal to the two-year average of property taxes last levied on the utilities before TVA purchased them. These payments are subtracted from a second payment made to the states, which is based on two factors. The first factor is the proportion of the value of all TVA property that is located in each state; the second factor is the proportion of gross proceeds from all TVA power sales that are made in each state, excluding sales to the federal government. The statute sets a maximum limit of 5 percent of gross proceeds on total payments to both states and counties. It also sets a minimum payment of \$10,000 annually to each state, including payments to its counties.⁶⁵

Columbia River Basin Project. The 1935 Columbia River Basin Project is a multipurpose water development project in Washington State.⁶⁶ In developing the project, the Department of the Interior temporarily acquired large tracts of privately owned land to reduce speculation. Until the lands were resold to settlers, Congress authorized the Secretary of the Interior to enter into agreements for payments in lieu of taxes with the state and local governments containing the acquired lands. The statute requires that these payments be made from funds derived from leasing of these lands prior to their sale, and the payments may not exceed the amount of taxes that would be paid if the lands continued to be privately held.⁶⁷

The 1944 Rivers and Harbors Act. In 1944, Congress authorized the Secretary of Agriculture to undertake eleven watershed improvement projects scattered across the country.⁶⁸ The Secretary had authority to acquire lands as needed to carry out these projects and to make annual payments in lieu of taxes to the relevant county. Although the statute remained in force for many years, the Department of Agriculture never acquired any lands for these projects or made any payments under this statute.

The PILOT provision spelled out in the law was fairly standard. It set the payment level at 1 percent of the purchase price of the lands acquired, or 1 percent of their value if they were not purchased. The Department of Agriculture could not make acquisitions without state consent. No use restrictions were imposed in the statute.

Migratory Bird Conservation Act. In 1935, counties containing federal wildlife refuges began receiving 25 percent of net revenues generated from the sale of animals, minerals, and other materials

from refuge lands and from leases for public accommodations, concessions, or facilities on them.⁶⁹ The statute required counties to use the revenues for public schools and roads.

This system of sharing receipts proved detrimental to the federal wildlife conservation program, however. Differences in federal management of individual wildlife refuges as well as differing revenue potential led to great disparities in the level of shared local revenues. Counties containing lands that the Department of the Interior wanted to acquire for refuges frequently resisted acquisition since there was no guarantee that they would receive any shared revenues to compensate for losing a portion of their tax base. This resistance effectively blocked fulfilling the purpose of the wildlife conservation program because state permission was required before land could be acquired, and states were often unwilling to go against the counties' wishes.

In 1964, Congress amended the law to address the fiscal inequities and impediments to acquisition.⁷⁰ There was no change in treatment of revenues from public domain lands in wildlife refuges, but the amendments contained new provisions for acquired lands that combined the payment in lieu of tax approach with the revenue sharing approach. Each year, counties containing these lands received the greater of 25 percent of net revenues, or .75 percent of the value of the lands, excluding the value of improvements made after federal acquisition.⁷¹ The basis for determining payment levels under the second method, the value of the lands acquired, was to be adjusted every five years. Congress imposed an upper limit on payments to counties, stipulating that total payments for a year could not exceed net receipts.

In 1978, Congress amended the law again in several significant ways. First, it added a third method for calculating payments for acquired lands. Counties now receive the larger of (1) 75¢ per acre, (2) .75 percent of fair market value, or (3) 25 percent of net revenues. Second, Congress removed the upper limit for total annual payments. If net receipts from refuges are not sufficient to cover the payments to counties, Congress may appropriate the difference.⁷² Third, the 1978 amendments eliminated the requirement that counties use these payments for schools and roads. Counties must, however, distribute the payments to other units of local government which have incurred property tax losses due to the existence of a refuge.

The Boundary Waters Canoe Area. In 1948, Congress authorized the Secretary of Agriculture to make payments in lieu of taxes in order to expedite acquisition of lands for the Boundary Waters Canoe area, a wilderness area designated in the Superior National Forest in Minnesota.⁷³ The justification for this special treatment was that the state would receive little or no revenues from wilderness management under the provisions of the National Forest Revenue Act.

Because some of the lands for the new unit were to be acquired from private owners, local governments would be likely to sustain a real tax loss.⁷⁴

The State of Minnesota receives the PILOT and must distribute the funds to the three counties containing the Boundary Waters Canoe Area lands. The payment is calculated as three-fourths of one percent of the appraised value of the lands. The land must be reappraised every ten years. The statute places no restrictions on the use of these funds.⁷⁵

Grand Teton National Park. In the 1920s, John D. Rockefeller, Jr., bought 33,000 acres in Teton County with the intent of donating the land to the federal government for a public park. The county objected strongly to this plan since 95 percent of the land in the county was already federally owned, and local property taxes were double the state average. The county insisted that the creation of a tax-exempt park would burden it unfairly.⁷⁶

The Rockefeller family finally conveyed the lands to the federal government in 1949, and Congress included a PILOT provision in the legislation creating the park in the following year.⁷⁷ For the first ten years, the state of Wyoming would receive an amount equal to the taxes last assessed on the donated land and any improvements on it. For the next ten years, the PILOT would decline by 5 percent each year, and payments would stop after twenty years. Congress stipulated that the state pass these payments directly to the county but placed no use restrictions on them. The PILOT could not exceed 25 percent of visitor fees collected from both the Teton park and from Yellowstone National Park.

St. Lawrence Seaway Act. In the 1954 St. Lawrence Seaway Act, Congress established the St. Lawrence Seaway Development Corporation, authorizing it to enter into agreements with Canada for joint construction, operation, and maintenance of the St. Lawrence Seaway and Power Project.⁷⁸ The development corporation could acquire land for the project and to make payments in lieu of taxes to state and local governments with respect to lands that had been subject to taxation prior to their acquisition.⁷⁹

The statute gives the corporation discretion to decide the amount and terms of the PILOT, merely directing it to limit payments to the taxes that would be paid on the property were it privately owned. The corporation also has the authority to make larger payments when its actions impose special burdens upon the state or local government. The legislative history does not explain why this PILOT provision is so loosely structured. The Congressional committee report on the legislation simply states that it follows current policy for making payments in lieu of taxes on federally acquired property previously subject to taxation.⁸⁰

Trinity River Basin Project. Congress authorized construction of the Trinity River Basin Project in 1955 for the purposes of irrigation, power generation, and flood control. The statute contained a PILOT provision applicable to lands acquired for the project and also provided for impact-type payments for road maintenance and repair during the construction phase. Construction appropriations and gross revenues of the project once it was operating would provide the source of funds for payments equal to the taxes previously contributed by the acquired property to Trinity County.⁸¹

The committee report justifies PILOT provisions for this type of project because the federal government already owned 70 percent of lands in the county, and removing additional property from the tax base would impose an unfair burden.⁸²

The statute calculates the PILOT by applying the current tax rate to the assessed valuation of the property at the time of acquisition. The tax rate may vary, unlike most similar programs, but the value of the property remains fixed, whether or not there is a general revaluation of other property in the county.⁸³

Payments in Lieu of Taxes Act of 1976

The 1976 Payments in Lieu of Taxes Act⁸⁴ constitutes a significant departure from the PILOT statutes that preceded it. First, it establishes minimum payments to local governments whose jurisdictions contain certain types of public lands. Second, it applies to several categories and vast acreage of public lands for which resource revenue sharing payments may already be made. Third, it establishes a limited PILOT program for national parks and other areas that by law do not support revenue- or fee-producing activities and which previously provided no compensating payments to state or local governments. And fourth, it specifies that Congress makes general fund appropriations for these payments.

The act establishes two separate payments for public lands. The federal government makes the first and more comprehensive payment for "entitlement lands." This definition includes all lands administered by the Bureau of Land Management, all national forest and national park lands, lands used as reservoirs for U.S. Corps of Engineers and Bureau of Reclamation water projects, dredge disposal areas administered by the Corps of Engineers, and inactive and semiactive Department of Army lands which provide no impact aid.⁸⁵ Acquired lands are included in these categories if they were subject to property taxes before being conveyed to the federal government.

The payments made for entitlement lands supplement eight types of resource revenue sharing payments so as to guarantee that local governments receive a minimum annual payment per acre. Under this

provision, local governments receive the greater of (1) 75¢ per acre, less any payments it receives under the National Forest Revenue Act, the Mineral Leasing Act of 1920 and that for acquired lands, the Taylor Grazing Act, the Bankhead-Jones Farm Tenant Act, the Boundary Water Canoe Area statute, the Federal Water Power Act, and payments from the sale of materials on public lands; or (2) 10¢ per acre, regardless of shared resource revenue payments. The upper limit for this payment varies from \$50 per capita in areas with a population of 5,000 or less to \$20 per capita for areas with a population of 50,000, with a maximum allowable payment of one million dollars.⁸⁶ Units of general local government such as counties, townships, municipalities, and boroughs receive these payments directly, and they may be used for any government function.

The second payment authorized in the 1976 Payment in Lieu of Taxes Act is a payment of limited duration made to counties in lieu of taxes for certain acquired lands. The provision applies to lands acquired after 1970 for addition to the National Parks and Wilderness Preservation Systems, excluding lands that were not subject to real property taxes before the federal government acquired them.⁸⁷ Counties receive a payment of 1 percent of the fair market value of the land as of the date of acquisition, for five years. Any payment under this provision may not exceed the taxes last paid when the land was in private ownership. The counties receiving these payments must share them to other units of local government and school districts that lost tax revenues because of the federal acquisition.

The Senate Committee report on the bill recognizes the need to offset the burden imposed by tax immunity of federal lands by providing minimum payments to local governments containing such lands.⁸⁸ The payments for entitlement lands provide all local governments with at least 10¢ per acre more than they received before, up to the per capita limit. The committee report justifies the additional payments as more equitable than resource revenue sharing for compensating local governments for tax losses, both actual and potential, and for costs imposed by activities on public lands. The new system provides payments for the first time for lands--national parks and wilderness areas--where Congress intends federal management to limit revenue-generating activities. The report points out that tourism to these areas imposes costs on local governments but that the fiscal benefits of tourism--income and sales taxes--usually accrue to state government.

The Senate committee report also justifies the payments for entitlement lands as a means of reducing the disparities in resource revenues due to variations in the productivity of public lands, and for reducing the annual variation of resource revenue sharing receipts. The greater stability in payments facilitates local government budgeting.⁸⁹ Finally, the report recognized that a payment based on acreage rather than resource revenues removes

pressures from local governments for federal land management policies that generate higher revenues but that may not be consistent with conservation, sustained yield, or environmental goals. Although the committee preferred a tax equivalency method in theory as the basis for calculating payments in lieu of taxes, they adopted a flat sum method, citing numerous administrative difficulties with the alternative approach.⁹⁰

The second payment authorized under the 1976 Payments in Lieu of Taxes Act addresses the problem of the loss of local tax revenues due to federal acquisition of private lands for preservation. The committee report states that the five-year payment of 1 percent of the value of the lands will "equalize the fiscal burden caused by the acquisition . . . and to reduce the immediate and direct financial impact on the affected local jurisdiction."⁹¹ The report also suggests that this provision will help overcome local opposition to creation of new parks from private land that is valuable to our national heritage.

In summary, the Payments in Lieu of Taxes Act of 1976 broadened the base for federal compensation for public lands, and established a minimum annual payment. It broke with the usual practice by financing payments in lieu of taxes from general fund appropriations instead of from dedicated revenues generated by development and use of the public lands.

PILOT Formulas

Formulas developed by Congress over the years to allocate payments in lieu of taxes may take several forms, ranging from flat dollar amounts to tax equivalency measures of varying complexity. Table 48 summarizes the method of calculating payments and the recipient unit of government for the programs described above. Six of these methods attempt to approximate tax equivalency directly, two laws provide for negotiated payments, and two provide for fixed payment amounts.

Tax equivalency measures generally apply a rate factor to the value of the property in calculating the payment. Some programs allow periodic revaluation of the property and adjustments of the rate factor while others do not. The Coos Bay Wagon Road law allows both factors to be adjusted while the Department of Agriculture water projects law specifies both factors as constants. The Boundary Waters Canoe Area program allows for periodic reappraisals of the property value, but the Trinity River Basin law holds the property value constant and allows the rate factor to vary with the local tax rate.

Table 48. Federal Payments in Lieu of Tax Programs, by Type and Recipient

Type of Payment	<u>RECIPIENT</u>		
	Counties	States & Counties	States
Tax Equivalency	Reposessed Coos Bay Wagon Road Grant Lands 1919	Tennessee Valley Authority 1933	
	Designated Watersheds under Dept. of Agriculture 1944		
	Boundary Waters Canoe Area 1948		
	Grand Teton National Park 1950		
	Trinity River Basin Project 1955		
	Wildlife Refuges (acquired lands) 1964		
Negotiated	St. Lawrence Seaway Act 1954	Columbia River Basin Project 1937	
Fixed	Payments in Lieu of Taxes Act 1976		Boulder Canyon Project 1940

Source: Adapted from Advisory Commission on Intergovernmental Relations, *The Adequacy of Federal Compensation to Local Governments for Tax Exempt Federal Lands*, Washington, D.C., ACIR, 1978, p. 21.

OCS Revenue Sharing

The Submerged Lands Act of 1953

Coastal states have a long history of activism regarding the oceans off their shores. Most claimed jurisdiction over the submerged lands for a distance of three miles from their shores well before the Second World War. Under this claim, California, Texas, and Louisiana began in the 1920s to grant oil and gas leases on submerged lands and levied taxes on production interests and improvements.⁹² Although the federal government initially tacitly recognized the states' claims, the Truman Administration reversed this position in 1945 to claim the submerged lands outside the inland waters of states for the federal government. The federal government brought suit against the State of California claiming title to these lands and their resources. The Supreme Court agreed in U.S. v. California that the federal government did have jurisdiction over submerged lands due to considerations of national defense and international relations.⁹³

Following this ruling, Representatives from coastal states immediately introduced a number of bills in Congress dealing with submerged lands within states' historic boundaries. Some of these bills left submerged lands in federal ownership but provided for revenue sharing with the states.⁹⁴ In 1953, Congress enacted two laws redefining the federal claim to the continental shelf lands. The Submerged Lands Act⁹⁵ granted states ownership and proprietary use of all lands under their navigable waters in the territorial sea, generally three miles from shore. The Outer Continental Shelf Lands Act (OCSLA) gave the Secretary of the Interior authority to manage submerged lands seaward of the territorial limit.⁹⁶ The OCSLA authorized federal leasing of minerals on the Outer Continental Shelf but provided the Secretary with minimal leasing, development, or other policy guidance.

Representatives of coastal states attempted, but failed, to write a revenue sharing provision into the 1953 legislation. The opinion prevailed that coastal states would reap substantial benefits from OCS development through local corporate and individual property taxes and from corporate and individual expenditures associated with the development. The majority of Congress prevailed in the opinion that these benefits, along with state revenues derived from development of resources on submerged lands within state jurisdiction, adequately satisfied state needs. Further, many members of Congress felt that states had no valid claim to a share of revenues from federal property and activities outside state boundaries.⁹⁷

In the 1950s and 1960s, most federal OCS leasing occurred off the coast of southern California and in the Gulf of Mexico. OCS leasing attracted little national interest during this period of low prices and abundant, stable energy supplies. The 1969 Santa Barbara oil spill ended this lack of concern, however; coastal states and environmental and other groups became instantly aware of the impacts of OCS activity on state and local governments and the coastal environment. Shortly thereafter, falling domestic energy production and the Arab oil embargo of 1973 had an equally dramatic effect, leading to federal plans to pursue rapid OCS energy development.⁹⁸

Federal Impact Assistance for OCS Development Effects

While the federal government has accelerated its OCS leasing activities, environmental and citizen organizations, fishing industry interests, and state and local governments have expressed increasing concern over possible adverse onshore effects of rapid development. In 1976, Congress addressed this issue by establishing the Coastal Energy Impact Program (CEIP) to provide loans and grants to assist states and localities mitigate problems caused by OCS energy activities.⁹⁹

The CEIP, amended in 1978 and 1980,¹⁰⁰ is a complicated program composed of three elements. The first is a formula grant program for providing new or improved public facilities and services, or for preventing or mitigating unavoidable losses of environmental or recreational resources that result from OCS and coastal energy activity. States may receive grants calculated by a three-part formula involving the amount of OCS leasing and production adjacent to the state and the amount of oil and gas first landed in the state. These funds must be spent or committed within two years, or they must be returned to the federal government.

The second part of the CEIP consists of discretionary grants that the Secretary of Commerce may make to a coastal state. States are eligible for grants for the purposes of (1) planning for the effects of energy development in the coastal zone, (2) assistance in fulfilling state responsibilities under the OCSLA, or (3) preventing or reducing environmental or recreational resource losses due to coastal energy activities or the transportation or storage of coal.

Under the third part of the CEIP, states receive loans, bond guarantees, and a third category of grants. The loans and bond guarantees may be used to provide new or improved public facilities and services that are necessary due to coastal energy activity. The grants are made to assist states in meeting loan and bond obligations where the energy activity fails to provide adequate revenues to offset new indebtedness. States may also receive grants to compensate for environmental or recreational resource losses that cannot be assessed against any identifiable source, and grants to study and plan for the economic and environmental impacts of energy facilities located in the coastal zone.

Sponsors of the CEIP hoped that it would moderate state concern over social, economic, and environmental disruption from OCS resource development. They also hoped to encourage rapid OCS development by relating the amount of aid available to each state from the first type of grant to the volume of oil and gas produced off its shores and to the level of new energy activity that occurs in it.

As the final vote approached on the CEIP bill, a proposed amendment to the bill made receipt of the formula grants contingent upon a finding that the loans or bond guarantees also provided under the legislation were unavailable. Although many supporters of the program opposed this provision, Congress adopted it in the end to avoid a threatened executive veto of the compromise bill.¹⁰¹

Senator Hollings of South Carolina explained the rationale for this restriction:

The primary assistance offered by the [new aid] program . . . for financing public facilities and services made necessary by any coastal energy activity are federal loans and bond guarantees, not grants. Initial assistance . . . is in the form of credit rather than grants because in many cases the adverse fiscal impacts experienced by a coastal state or local government will only be temporary and will be offset later by increased tax revenues from the coastal energy activity involved.¹⁰²

As originally enacted, the formula calculating the amount of state grants contained four factors. One-third of the total appropriations for these grants was distributed according to the acreage that was newly leased during the preceding year from the OCS adjacent to the states. Another third was distributed according to the number of persons residing in each state who obtained new jobs in the preceding year as a result of new or expanded OCS energy activities. One-sixth was distributed for the volume of oil and gas produced from leased OCS lands adjacent to a state during the preceding year, and one-sixth was distributed according to the amount of OCS oil and gas first landed in a state in the preceding year.¹⁰³

Congress amended this formula in 1978, eliminating the new employment factor because of difficulty in acquiring accurate data, and increasing proportionally the weights for the other factors.¹⁰⁴ Proposals introduced in 1978 for instituting OCS revenue sharing instead of making these changes to the grant formula died in committee. The House committee report explained that revenue sharing would allow states too much discretion in using the funds. The committee wished to ensure the funds would be used to support comprehensive coastal management as structured in the Coastal Zone Management Act and the Outer Continental Shelf Lands Act.¹⁰⁵

Rationale for OCS Revenue Sharing

Federal support has recently been reduced for a variety of coastal programs, including the Coastal Energy Impact Program, the Coastal Zone Management Program, the National Sea Grant Program, and other programs for living marine resource management. The Reagan Administration has supported the reductions by asserting that these programs compete with other federal programs, and that they serve state, not national, interests and, therefore, should be financed by states.¹⁰⁶

This argument contradicts stated Congressional rationales for instituting the programs and providing them with federal support in the first place. Several Congressional leaders have reaffirmed that these programs serve important national interests, which include planning for siting of onshore OCS facilities, pipeline corridors, disposal of dredging materials and coal port expansion as well as management of marine fisheries, and protection of coastal resource systems.¹⁰⁷ Congress may choose to insulate these coastal programs from further budget reductions by funding them through revenue sharing.

The large and increasing sums received by the federal government from OCS leasing and severe fiscal problems of many states add impetus to proposals for OCS revenue sharing. Without federal assistance, most states will have to weaken or terminate coastal management programs. This may lead to inefficient decision making, lengthened state permit review schedules, and increased litigation against federal lease sales. All of these consequences would delay or obstruct OCS energy development plans and affect other national interests in marine and coastal resources management.

Finally, there is an equity issue in OCS revenue sharing. States adjoining OCS lands undergoing energy exploration and development are at a disadvantage compared to states containing onshore federal resource lands. OCS mineral development is the only exception to a long-standing policy of sharing with affected states a significant portion of resource development receipts from public lands. The House Committee on Merchant Marine and Fisheries has also noted that funding for impact assistance for onshore energy development has been increasing at the same time funding for the CEIP has declined.¹⁰⁸ The committee and its Senate counterpart have agreed that federal OCS policies are inequitable, requiring a legislative remedy in order to meet the national objectives of developing OCS energy resources, as well as manage other ocean and coastal resources. OCS revenue sharing is one proposed remedy.

The Current OCS Revenue Sharing Proposal

Proposals to share federal OCS revenues with the states have arisen in Congress repeatedly during the past decade without any apparent resolution of the issue. In the 98th Congress, however,

both the House and Senate have passed OCS revenue sharing bills. The two versions differ in a number of particulars, including the portion of federal OCS revenues to be shared, the form of state payments, allocation formulas, and requirements for pass-through of funds to local governments. In September, 1984, a conference committee completed work on a compromise bill containing the following major features.

The conference committee bill establishes a fund dedicated from annual deposits of 4 percent of total federal OCS lease revenues up to a maximum level.¹⁰⁹ The ceiling level for deposits to the fund begins at 300 million per year but increases by 5 percent annually after 1985. The bill directs the Secretary of Commerce to use a portion of the funds to support the National Sea Grant College Program as well as to establish and support a National Coastal Resources Research and Development Institute at Oregon State University. The remaining funds are available as block grants to coastal states, which may use them for activities authorized by the Coastal Zone Management Act and the CEIP and for the protection, enhancement, and management of living marine and coastal resources.

The formula for allocating the grants among coastal states contains five equally weighted factors. The first factor is a measure of current OCS activity adjacent to the states, including the acres leased and the amount of oil and gas landed in the state. The second factor varies with future planned OCS lease sales adjacent to a state, and the third criterion covers coastal-related energy facilities located in each state.¹¹⁰ The fourth measures shoreline mileage; the fifth measures coastal county population. While Alaska is at a disadvantage in relation to other coastal states in terms of population, the factor measuring shoreline mileage, which receives equal weight, works to the state's advantage.

Under this proposal, each coastal state with an approved coastal zone management planning program receives at least 1.62 percent, and territories, 0.5 percent, of the total amount available for the block grants in any year. No state or territory may receive more than 15 percent of the fund in a single year. States receiving block grants must consult with local authorities with respect to allocation of grant funds within the state and must give at least one-third of grant funds directly to the local governments. The bill directs states to place special emphasis on local projects that mitigate the impacts of coastal energy development activities.¹¹¹

Summary and Conclusions

In this chapter, we have analyzed the legislative history of several types of programs sharing federal revenues from the public lands with state and local governments. Programs sharing property values of the federal public domain have arisen as a form of compensation to states for the continued imposition of federal

management of lands affecting the state and its people. Congress has typically attached these revenue-sharing measures as part of major initiatives to retain resources in federal ownership and control. Examples of this type of legislation are the National Forest Revenue Act (1908), the Mineral Leasing Act (1920), and the Taylor Grazing Act (1934).

Congress has typically initiated programs sharing property values of federal acquired lands as part of legislation authorizing major federal purchases of private land for development or conservation purposes. Programs initiating payments in lieu of taxes are typically associated with the objective of achieving equity in the fiscal treatment of the federal lands. They attempt to reduce disparities among state and local government receipts from shared federal resource development revenues and user fees, which may arise from differences in federal management objectives as well as from variations in the value of the public lands. When the objectives of a federal land acquisition program have moved away from development and towards preservation, Congress has typically replaced sharing of resource revenues with a payment in lieu of taxes clause as the mechanism to compensate local governments for the imposition of the program's political and fiscal costs.

There is an essential difference in economic interpretation between the payments in lieu of taxes approach and the resource revenue-sharing approach. Payments in lieu of taxes attempt to offset local property tax revenue local governments may lose due to the tax immunity of federal lands. Ideally, the level of the payments should approach the level of taxes paid on similar private lands in the same jurisdiction. Resource revenue sharing programs, on the other hand, generally share property values accruing to the federal landowner from resource development.

If there is no development, or if development does not produce returns in excess of development costs, then the landowner does not receive any resource revenues. Landowner payments of this type must come out of the economic rent produced from resource development. If federal managers dispose of resources competitively, then the resource revenues contain substantially all the economic rent. In some cases, economic rents from resource development will greatly exceed the level of property taxes that local governments would collect on similar private lands. In other cases, such as with most of the acquired lands, economic rents from resource development may be small or nonexistent so that local governments are likely to receive more revenues with a program sharing property values than with a payments in lieu of taxes provision.

Table 49 shows the levels of shared revenues from federal lands received in federal fiscal year 1982 by the eleven contiguous western states plus the state of Alaska (including payments to local governments within those states). These twelve states contain

TABLE 49.
SHARED REVENUES FROM FEDERAL LANDS RECEIVED
BY 12 WESTERN STATES, FEDERAL FISCAL YEAR 1982

(million dollars)

State	National Forest Revenues	Mineral Leasing Act	BLM Surface*	PILOT Act	Total
Alaska	3.8	23.0	-	3.5	30.3
Arizona	5.7	5.3	0.6	8.2	19.8
California	42.0	29.8	0.4	10.9	83.1
Colorado	1.8	38.0	0.2	6.6	46.6
Idaho	9.1	4.0	0.4	6.9	20.4
Montana	8.1	15.5	1.0	7.2	31.8
Nevada	0.3	11.5	0.9	5.1	17.8
New Mexico	2.5	151.7	0.7	8.9	161.6
Oregon	95.1	1.5	98.5	2.5	197.6
Utah	1.0	75.4	0.3	7.9	84.6
Washington	29.4	0.1	0.1	1.6	31.2
Wyoming	<u>1.0</u>	<u>149.0</u>	<u>0.9</u>	<u>7.0</u>	<u>157.9</u>
Total, 12 States	199.8	504.8	104.0	76.3	882.7
Total, U.S.	231.2	536.1	104.2	95.5	967.0
Percent, 12 States	86.4	94.2	99.8	79.9	91.3

* Includes Taylor Grazing Act, Sale of Materials, O and C lands, etc.

- Means less than 0.05.

SOURCE: U.S. Department of Treasury, "Federal Aid to States, Fiscal Year 1982."

essentially all of the public domain lands, so it is not surprising to learn from the table that they received over 90 percent of the shared federal revenues in that year. The amounts individual states received varied widely from a low of around \$18 million for Nevada to over \$150 million for New Mexico, Oregon, and Wyoming.

As shown in Table 49, the major resource revenue sharing programs distributed \$870 million to state and local governments in 1982 out of a total of around \$2.2 billion in landowner payments for federal onshore property in the twelve western states. Mineral leasing and national forest revenues contributed over three-fourths of the total. Payments to local governments nationally under the Payments in Lieu of Taxes Act amounted to around \$100 million in federal fiscal year 1982. Except for the repossessed O&C lands, which contributed nearly \$100 million in shared timber receipts to Oregon counties, all of the other programs shared relatively small amounts of revenue.

Seen from the perspective of a legislative history spanning eight decades, current Congressional proposals for sharing OCS revenues are neither consistent in approach nor sufficient in scale to match the historical precedents afforded by the payment in lieu of taxes or the resource revenue sharing programs. The evolution of PILOT legislation culminating with the Payment in Lieu of Taxes Act of 1976 shows a definite trend toward treating the payments as an entitlement grant appropriated out of general fund revenues. Both the House and the Senate OCS revenue sharing proposals dedicate a share of the resource revenues in order to fund the program. More importantly, however, the OCS revenue-sharing bills make no attempt to relate the level of payments to the reduced ability of local governments to raise property tax revenue to finance public services. Not only are the submerged lands immune from taxation, as is the case with onshore federal property, but the state and local governments may not tax private property located on the federal OCS either.

If the Congressional sponsors of the recent OCS revenue sharing proposals had intended the measures to correspond to a payment in lieu of taxes approach, then the level of payments specified in the bills would logically correspond to some notion of foregone property tax revenue. Determining an assessed value for OCS property is not difficult. There are established methods for valuing petroleum and mining property, and many states--among them Alaska--already assess property taxes on offshore exploration, production, and transportation property within their three-mile jurisdiction.

The proposed OCS revenue-sharing laws are also inconsistent with the numerous precedents established in prior federal legislation sharing resource revenues with the states. On the one hand, the OCS bills in both houses of Congress contain complicated formulas for reallocating revenues collected in one region to local governments

in other regions. Both bills include a minimum share of the revenue for each state; the Senate bill even includes a ceiling of 15 percent on any state's share of the total, regardless of the share computed using the statutory allocation formula. The legislative history of shared resource revenues for the federal lands contains no precedent for these reallocations and limits.

The proportion of federal OCS resource revenue shared with state and local governments ranges from zero to five percent in the Congressional proposals. This contrasts with a range of 25 to 50 percent for the major onshore revenue sharing programs. The state share of federal resource revenue under the Mineral Leasing Act of 1920, the precedent most closely analogous to the OCS case, has been 50 percent since 1975. A direct comparison of OCS revenue sharing proportions and proportions typical of onshore programs is probably inappropriate since Congress did address the issue of proprietary rights to submerged lands in the Submerged Lands Act of 1953. At the time, awarding the states property rights three miles seaward from the coast seemed an equitable division of the wealth of the submerged lands, given the abundance of unexploited oil and gas and other subsurface resources remaining onshore, and the limited technology and high cost of offshore mineral exploration and development.

With the unforeseen technological and economic changes which have occurred in the past 30 years, however, the three-mile division is no longer as equitable as it seemed in 1953. There is undoubtedly a great variation among the states in the relative values of the state and the federal offshore estate, but it is unlikely that the state lands generally contain more than 10 percent of the total property value of the Continental Shelf. Taking this into account, the historical precedents suggest that realistic proposals for sharing OCS revenues with the coastal states will contain proportions ranging from one-sixth to one-third of the federal receipts. Given the long history of legislative precedents, it is unlikely that Congress can lay the issue of OCS revenue-sharing to rest until it has enacted a program of comparable scope.

ENDNOTES

¹G. Kevin Jones. "Understanding the Offshore Oil and Gas Controversy." Gonzaga Law Review, V. 17, No. 2, p. 226.

²U.S. Congress, Senate Report No. 753, quoted in Jones, "Understanding the Offshore Oil and Gas Controversy," p. 231.

³Intergovernmental tax immunity is not explicitly mandated by the U.S. Constitution. Judicial precedent, in fact, established the principle of dual sovereignty, under which federal and state governments are immune from taxes levied by the other. Although recent court decisions have qualified the doctrine of tax immunity, states have no authority to tax any federal government instrumentality that Congress chooses to exempt. Advisory Commission on Intergovernmental Relations, The Adequacy of Federal Compensation to Local Governments for Tax Exempt Federal Lands, p. 18.

⁴Several land purchases by the federal government added vast areas to the public domain, including the Louisiana Purchase (1803), the Florida Purchase (1819), the Oregon Compromise (1846), the Mexican Treaty (1848), the purchase from Texas (1850), the Gadsden Purchase (1853), and the Alaska Purchase (1867). Marion Clawson and Burnell Held, The Federal Lands: Their Use and Management, p. 21.

⁵*Ibid.*, p. 22.

⁶*Ibid.*, p. 23.

⁷EBS Management Consultants, Inc., Payments in Lieu of Taxes and Revenue Sharing on Public Lands, V. 2, p. LA-16.

⁸Benjamin H. Hibbard, A History of the Public Land Policies, pp. 171-190.

⁹*Ibid.*, pp. 172-175.

¹⁰*Ibid.*, pp. 175-177.

¹¹*Ibid.*, pp. 188-190.

¹²Section 6(f) of the Alaska Statehood Act, 1958, 72 Stat. 339, 341 (1958).

¹³EBS, Payments in Lieu of Taxes and Revenue Sharing on Federal Lands, V. 2, pp. LA-22-LA-23 (hereinafter cited as PILOT and Revenue Sharing).

¹⁴Act of July 31, 1947, 61 Stat. 681 (1947); 30 U.S.C. 601-603 (1976).

¹⁵Act of August 31, 1950, 64 Stat. 571 (1950).

¹⁶A withdrawal is a taking of land for a public purpose. Both Congress and the Executive have the power to make withdrawals. Withdrawals may vary as to their term; that is, some are for a limited time period while others are permanent. The interest that is withdrawn also varies. "It may range from a small potential scenic reserve superimposed upon a prior withdrawal of the same land . . . to the equivalent of a full fee simple interest." Several withdrawals may apply to the same land, leading to administrative complexities when more than one agency has jurisdiction. Duncan A. Harkin, James B. MacDonald, William B. Lord, and Richard L. Hilliker, Federal Land Laws and Policies in Alaska, pp. 159-160.

¹⁷Clawson and Held, The Federal Lands, p. 236; and EBS, PILOT and Revenue Sharing, V. 1, pp. 18-19.

¹⁸Act of May 23, 1908, 35 Stat. 251, 260 (1908); 16 U.S.C. 500 (1976).

¹⁹EBS, PILOT and Revenue Sharing, V. 1, pp. 17-19; Clawson and Held, The Federal Lands, p. 236.

²⁰Joseph M. Chomski and Constance E. Brooks, The Sagebrush Rebellion: A Concise Analysis of the History, the Law and Politics of Public Land in the United States, p. 21.

²¹National Forest Management Act of 1976, 90 Stat. 2961 (1976).

²²Act of February 25, 1920, 41 Stat. 437, 451 (1920).

²³Section 35 of the Mineral Leasing Act of 1920, 30 U.S.C. 191 (1976). Leasable minerals include oil, natural gas, oil shale, coal, potassium, sodium, phosphate, native asphalt, solid and certain other minerals. States and the federal government do not receive lease revenues from nonleasable minerals. Harkin et al., Federal Land Laws and Policies in Alaska, p. 684.

²⁴EBS, PILOT and Revenue Sharing, V. 2, pp. LF-3 - LF-4.

²⁵Ibid., pp. LF-4 - LF-5.

²⁶Mineral Leasing Act Amendment, 61 Stat. 119 (1947).

²⁷EBS, PILOT and Revenue Sharing, V. 2, p. LF-6.

²⁸Federal Coal Leasing Amendments Act of 1975, 90 Stat. 1083, 1093; 30 U.S.C. 191 (1976).

²⁹Federal Land Policy and Management Act of 1976, 90 Stat. 2770 (1976).

³⁰41 Stat. 1063, 1077 (1920); 16 U.S.C. 810 (1976).

³¹EBS, PILOT and Revenue Sharing, V. 2, p. LG-1.

³²Quoted in EBS, PILOT and Revenue Sharing, V. 2, p. LK-1.

³³Act of June 28, 1934, 48 Stat. 1269, 1273 (1934); 43 U.S.C. 315i-315j

³⁴Clawson and Held report that the counties receiving these funds uniformly turned them over to grazing advisory boards for range improvements. The Federal Lands, p. 238.

³⁵EBS, PILOT and Revenue Sharing, V. 2, pp. LK-4 - LK-5.

³⁶Taylor Grazing Act Amendments, 61 Stat. 790 (1947); EBS, PILOT and Revenue Sharing, V. 2, p. LK-2.

³⁷See EBS, PILOT and Revenue Sharing, V. 2, p. LK-5, note 11.

³⁸Ibid., p. LK-9.

³⁹Act of March 4, 1927, 44 Stat. 1452 (1927); 43 U.S.C. 316 (1976).

⁴⁰P.L. 94-258, Section 102, 90 Stat. 303 (1976); 42 U.S.C. 650 (1976). The reserve had been established by Executive Order in 1923 and administered by the Secretary of the Navy until its transfer in 1976. As a Naval Petroleum Reserve, no resource revenue sharing provisions applied.

⁴¹42 U.S.C. 6507 (1976).

⁴²Act of December 12, 1980, 94 Stat. 2957 (1980).

⁴³42 U.S.C. 6508 (1981).

⁴⁴EBS, PILOT and Revenue Sharing, V. 2, pp. LR-1 - LR-2.

⁴⁵Mineral Leasing Act for Acquired Lands, 61 Stat. 913, 915 (1947); 30 U.S.C. 355 (1976).

⁴⁶30 U.S.C. 352 (1976).

⁴⁷EBS, PILOT and Revenue Sharing, V. 2, p. LM-1.

⁴⁸U.S. Congress, Committee on Energy and Natural Resources, Legislative History of the Federal Land Policy and Management Act of 1976, p. 98.

⁴⁹7 U.S.C. 1012 (1976); 50 Stat. 522, 526 (1937).

⁵⁰Some lands acquired under the Bankhead-Jones Act have become part of National Forests. In this case, revenues from the lands are distributed according to National Forest Revenue Act provisions, i.e., to states, not to counties.

⁵¹Act of August 18, 1941, 55 Stat. 638, 650 (1941); 33 U.S.C. 70(c)(3) (1976).

⁵²EBS, PILOT and Revenue Sharing, V. 2, p. LN-2.

⁵³Act of July 13, 1926, 44 Stat. 915 (1926).

⁵⁴Act of August 28, 1937, 50 Stat. 874 (1937).

⁵⁵The Federal Lands, p. 240.

⁵⁶Act of May 24, 1939, 53 Stat. 753 (1939).

⁵⁷43 U.S.C. 1181 f-1 (1976).

⁵⁸43 U.S.C. 1181 f-2 (1976).

⁵⁹Boulder Canyon Project Act, 45 Stat. 1057, 1063 (1928).

⁶⁰EBS, PILOT and Revenue Sharing, V. 2, pp. LH-4 - LH-8.

⁶¹Boulder Canyon Project Adjustment Act, 54 Stat. 774 (1940); 43 U.S.C. 618(c) (1976).

⁶²43 U.S.C. 618(c) (1976).

⁶³Tennessee Valley Authority Act, 48 Stat. 58, 66 (1933).

⁶⁴EBS, PILOT and Revenue Sharing, V. 2, p. LI-5.

⁶⁵16 U.S.C. 831P (1982).

⁶⁶EBS, PILOT and Revenue Sharing, V. 2, p. LL-1.

⁶⁷16 U.S.C. 835c-1(a) (1982). The EBS report states that agreements were entered into with four counties in Washington State in 1948, which agreements were still in force in 1967. Each agreement provided that the counties received the smaller of (1) 50 percent of total leasing revenues from the lands or (2) a sum equal to taxes that would be assessed against the lands were they privately owned. PILOT and Revenue Sharing, V. 2, pp. LL-2 - LL-3.

⁶⁸1944 Rivers and Harbors Act, 58 Stat. 887, 905 (1944). EBS, PILOT and Revenue Sharing, V. 2, pp. LO-1 - LO-3.

⁶⁹Migratory Bird Conservation Act amendment, 49 Stat. 378, 386 (1935) as amended; 16 U.S.C. 715s (1982). The National Wildlife Refuge System includes wildlife refuges and ranges, game ranges, wildlife management areas, and waterfowl production areas.

⁷⁰Act of August 30, 1964, 78 Stat. 701 (1964).

⁷¹16 U.S.C. 715s (1976). Net revenues are gross receipts less expenses necessary for the disposition of refuge products or for the granting of privileges. EBS, PILOT and Revenue Sharing, V. 2, p. LAB-7.

⁷²The 1978 changes were made in P.L. 95-469, Refuge Revenue Sharing Amendment, Section 1(a)(3), 92 Stat. 1319, 1322 (1978); 16 U.S.C. 715s (1982).

⁷³Act of June 22, 1948, 62 Stat. 570 (1948).

⁷⁴EBS, PILOT and Revenue Sharing, V. 2, pp. LS-1 - LS-4.

⁷⁵16 U.S.C. 577g (1982).

⁷⁶EBS, PILOT and Revenue Sharing, V. 2, p. LU-1.

⁷⁷Act of September 14, 1950, 64 Stat. 849, 851 (1950); 16 U.S.C. 406d-3 (1982).

⁷⁸Act of May 13, 1954, 68 Stat. 93, 95 (1954); EBS, PILOT and Revenue Sharing, V. 2, p. LX-1.

⁷⁹33 U.S.C. 986 (1976).

⁸⁰EBS, PILOT and Revenue Sharing, V. 2, p. LX-2.

⁸¹Act of August 12, 1955, 69 Stat. 719, 720 (1955).

⁸²EBS, PILOT and Revenue Sharing, V. 2, p. LY-2.

⁸³Ibid., p. LY-4.

⁸⁴P.L. 94-565, 90 Stat. 2662 (1976), 31 U.S.C. 1601, 1607 (1976).

⁸⁵Not included as entitlement lands are national wildlife and game refuges; Bureau of Mines lands; Agricultural Research Service and Soil Conservation Service lands; lands of the Navy, Air Force, and Marines; or lands of other agencies (i.e., Department of Transportation, General Services Administration, NASA, and the Energy Research and Development Administration). The committee

report explained these were excluded because they do not require the same level of governmental services as entitlement lands and because in the case of active military installations and wildlife refuges, other in lieu payments are already made. Senate Interior and Insular Affairs Committee, Report No. 94-1262, pp. 13-14.

⁸⁶31 U.S.C. 1602 (1976).

⁸⁷31 U.S.C. 1603 (1976).

⁸⁸U.S. Congress, Senate Report No. 94-1262, Committee on Interior and Insular Affairs, pp. 8-9.

⁸⁹Subject to Congressional appropriation of the authorized payments. See Shands and Healy, The Lands Nobody Wanted, p. 229.

⁹⁰U.S. Congress, Senate Report No. 94-1262, p. 11.

⁹¹*Ibid.*, p. 14.

⁹²G. Kevin Jones, "Understanding the Offshore Oil and Gas Controversy," 17 Gonzaga Law Review, pp. 237-238.

⁹³332 U.S. 19 (1947). See also U.S. v. Louisiana, 339 U.S. 699 (1950) and U.S. v. Texas, 339 U.S. 707 (1950).

⁹⁴EBS, PILOT AND Revenue Sharing, v. 2, p. LW-2. The issue of ownership of the OCS was recently raised again in a lawsuit filed by thirteen Atlantic coast states. In 1975, the Supreme Court affirmed federal control of the OCS in United States v. Maine and held, furthermore, that states could claim no formal role in OCS decision making without a legislative mandate (420 U.S. 515 [1975]).

⁹⁵67 Stat. 31 (1953); 43 U.S.C. 1301-1315 (1976).

⁹⁶67 Stat. 462 (1953); 43 U.S.C. 1331-1343 (1976).

⁹⁷EBS, PILOT and Revenue Sharing, V. 1, p. 25, and V. 2, pp. LW-3-LW-5.

⁹⁸U.S. Congress, House Report 98-206, Committee on Merchant Marine and Fisheries, p. 16; and Jones, "Understanding the Offshore Oil and Gas Controversy," pp. 243-244.

⁹⁹Coastal Zone Management Act Amendments of 1976, 90 Stat. 1013, 1033 (1976); 16 U.S.C. 1456 (1982).

¹⁰⁰1978 amendments are found in P.L. 95-372, the Outer Continental Shelf Lands Act Amendments, 92 Stat. 629, 698 (1978); the 1980 amendments were made in P.L. 96-464, the Coastal Zone Management Improvement Act, 94 Stat. 2060, 2070 (1980).

¹⁰¹Congressional Quarterly, Inc., Energy Policy, p. 167. 16 U.S.C. 1456a (1982). See U.S. Congress, House Conference Report No. 94-1298, Joint Exploratory Statement of the Committee of Conference, p. 33.

¹⁰²Quoted in Congressional Quarterly, Energy Policy, p. 168. This restriction was removed two years later, after states complained it was particularly onerous. See U.S. Congress, House Report No. 95-590, p. 195.

¹⁰³Section 7 of P.L. 94-370, Coastal Zone Management Act Amendments of 1976, 90 Stat. 1013, 1033 (1976).

¹⁰⁴Section 501(a) of P.L. 95-372, Outer Continental Shelf Lands Act Amendments of 1978; U.S. Congress, House Report No. 95-590, pp. 194-196; and 15 C.F.R. 931, Subpart K.

¹⁰⁵U.S. Congress, House Report No. 95-590, p. 195.

¹⁰⁶U.S. Congress, House Report No. 98-206, p. 95.

¹⁰⁷Ibid., p. 46; and U.S. Congress, Senate Report 98-112, p. 10.

¹⁰⁸Ibid., p. 71.

¹⁰⁹Conference Report to accompany S. 2463 adopted Sept. 10, 1984. See U.S. Congress, House Report No. 98-1006, Ocean and Coastal Resources Management and Development Block Grant Act.

¹¹⁰For example, electric generating plants, petroleum refineries, pipelines, transmission facilities, and so on. Section 103(3) of S. 2463, Ibid.

¹¹¹The 98th Congress failed to approve S. 2463 before adjourning in October 1984.

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- Tennessee Valley Authority Act, 48 Stat. 58, 66 (1933); 16 U.S.C. 831 (1982).
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Act of June 22, 1948, Relating to Superior National Forest, 62 Stat. 568, 570 (1948); 16 U.S.C. 577 (1982).

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CHAPTER VII

CONCLUDING OBSERVATIONS

In this report, we have analyzed the historical pattern of economic rent generated and public revenues collected in Alaska and Texas, two states with major differences in resource ownership and regulation. We have examined the dominant factors which have affected the historical pattern of collection and distribution of public revenues. In addition, we have assessed the sensitivity of projected future public revenues to such factors as geologic and market risks, and revenue collection methods or other public policies. We concluded the analysis with an assessment of the possible effects of existing and proposed federal oil and gas policies on the state of Alaska's share of future economic rent.

In order to perform our analysis, we developed a number of new sources of information on the Alaska petroleum industry which may be useful to other researchers, public agencies, and analysts. For the analysis in Chapter II, we compiled and documented consistent data series on Alaska's oil and gas production, prices, and revenues by region, landowner, and revenue source. For Chapter III, we developed estimates of the historical revenues, costs, and distribution of economic rent from petroleum development in three regions of Alaska and two regions of Texas. For the analysis of Chapter IV, we developed a set of parameters for probable discoveries of new oil and gas fields in Alaska. We used these parameters to analyze the effects of state and federal policies on projected future oil and gas development decisions.

For Chapter V, we developed a simple but useful set of parameters for each of Alaska's known but as yet undeveloped oil fields on the North Slope, including estimated reserves, capital and operating costs, and beginning date of production. This permitted us to analyze the effects on development decisions of world price trends and public policies and, consequently, the sensitivity of federal and state revenues derived from oil and gas development in Alaska. Finally, in Chapter VI, we compiled the legislative history of federal-state sharing of land and resource revenues in order to analyze the proposed federal OCS revenue sharing legislation within this historical context.

Major Project Findings

Our analysis has led to a number of detailed conclusions discussed in each chapter, and we will not repeat these in detail here. However, we will summarize the major findings for the two general areas covered by the analysis. The first area pertains to the major factors which shape the pattern of resource development and revenues. The second concerns the distribution of lease revenues from public lands.

X

Factors Determining Pattern of Oil and Gas Revenues

Formulating appropriate state, interstate, and national policy on sharing energy resource revenues requires an examination of the total economic and fiscal picture of energy resource development. Focusing on one variable, such as the nominal state severance tax rates, is likely to lead one to erroneous conclusions for the direction of policy. Tax rates are only one of several important factors in determining the distribution of energy resource revenues among governments, producers, and consumers.

We have shown that four factors are typically more important than state tax rates in shaping the pattern of resource development and the distribution of resource revenues. These are:

- ✓ 1. Geologic good fortune--the location of accumulations of fossil fuel resources is randomly associated with state political boundaries.
- ✓ 2. Ownership of mineral rights--federal or state governments may retain title to subsurface estate, allowing them to receive proprietary payments such as royalties and lease bonuses.
- ✓ 3. Cost environment--some deposits of energy resources are much more costly to develop than others, and frontier regions such as Alaska are much more costly than onshore areas in the Lower 48.
- ✓ 4. World energy prices--individual states have very little ability to influence the markets for their energy products.

These four factors have profound consequences on both the amount and distribution of economic rents. Consider, for example, the combined importance of world prices and production costs. In Alaska, some oil and gas fields that are just becoming feasible to develop, such as the Endicott River field and portions of the Kuparuk reservoir, would not be feasible under the oil price levels prevailing in the early 1970s. In contrast, if a field geologically similar to the Kuparuk field were found in a state such as Texas, it would not only be feasible but would be considered a bonanza. This would hold true even under the early 1970s price scenario, due to the much lower development and operating costs in that state.

Effective tax rates on resource extraction are often different from the apparent nominal rates. Although the nominal severance tax rate on oil is over three times higher in Alaska than Texas, the lower wellhead value of North Slope oil means that the state severance tax take per barrel is only about twice as high as the average in Texas. Furthermore, while Texas receives substantial

revenues from gas production, Alaska realizes very little tax revenue from North Slope gas because high transportation costs have so far rendered the gas unmarketable. Thus, Alaska's effective tax rate per barrel of oil produced, including related gas revenues (which Texas receives but Alaska does not), roughly compares to that of Texas. *even w/ so diff. econ. conditions, etc. means tax rate is same.*

We expect Alaska's oil production to decline through the 1990s. However, as the Prudhoe Bay field is depleted, revenues (after adjusting for inflation) will fall more rapidly than production. This is due to the economic limit factor (ELF) in the Alaska severance tax schedule, designed to make the tax burden disappear as production from an oil field becomes less profitable. Even as early as 1990, average effective severance tax rates will fall from nearly 15 percent in 1983 to around 10 percent. Several Cook Inlet fields will continue to produce without paying severance taxes.

In the near term, Alaska's relatively high oil severance tax collections are an important factor in the state's total fiscal position. In the longer term, they will play a reduced role. On the one hand, the declining production at Prudhoe Bay and the lower production per well projected for new fields on the North Slope will reduce the ELF and, thereby, reduce tax collections. On the other, even the somewhat reduced severance tax burden may affect economic feasibility of marginal fields, especially when combined with the state's royalty share. Indeed, it is possible that the state's severance tax may even play a negative role in future state revenues.

Seen in this context, attempts by Congress to limit state severance taxes may not have a severe long run impact on the State of Alaska's petroleum revenues. This is especially true if other means of raising petroleum revenues are available, specifically, the separate accounting method of assessing the corporate income tax. The analysis suggests that export restrictions on North Slope oil, Trans-Alaska Pipeline tariffs, and even alleged monopoly power in the west coast oil market may already be causing more serious losses to the state treasury. A corollary to this observation relates to the differing incentives offered by net profit shares and royalty shares in oil and gas leases on public lands. Although not without problems of their own, net profit share leases provided clearly superior economic incentives even to relatively low royalty shares for developing marginal fields.

Distribution of Lease Payments for Public Lands

The second major area of our findings concerns policies which directly affect the distribution of lease revenues from public lands. Congress has set a long list of historical precedents for compensating states (and local governments) for continued federal ownership and management of public lands with valuable developable resources. These laws have been continually broadened and

strengthened throughout this century so that there is now a system in place for sharing with the state or local governments at least 25 percent of all major resource revenues from federal lands within state boundaries.

The federal Outer Continental Shelf is the single giant exception to this rule of resource revenue sharing with the states. It is not reasonable to argue that coastal states are less affected by federal management of submerged lands than of upland areas. A more reasonable explanation of this historical exception is that Congress settled the issue of proprietary interest in the offshore public domain with the Submerged Lands Act of 1953. This law actually gave title to the states of submerged lands out to the three-mile line. Since technology prevailing at the time prevented offshore mineral extraction except in shallow, nearshore waters, this meant that the states received at least one-fourth, and possibly over one-half, of the value of the offshore public domain.

As technology improved and national energy policy developed in the early 1970s, the Department of Interior greatly expanded the federal leasing program. The change in technology, allowing exploration in deep water and far from shore, effectively created a large new federal public domain offshore from the coastal states. The distance offshore (or the water depth for that matter) makes no significant difference when it comes to state impacts and the diminished local control over development patterns.

In the same period since the early 1970s, there has been a rapid increase in the value of energy resources worldwide. This increase in value has served to magnify the value of the new public domain declared by the federal government. Seen in the historical context, the practice of the federal revenue-sharing with states of 5 or 6 percent of OCS lease payments departs significantly from the precedents of distributing 25 percent or more of gross federal receipts to the states.

Another federal program for compensating state and local governments for the tax-exempt status of property associated with federal property development is the system of "payments in lieu of taxes" (PILOT). This program is more recent and is in addition to any resource revenue sharing program that may apply. Offshore drilling and production platforms, pipelines, and terminals located beyond the three-mile limit may not be taxed by state and local governments, although these governments usually are affected by the development. PILOT formulas in existing law do not apply to OCS development but would yield up to 1 percent of assessed real property value if they did. This is an order of magnitude greater than contained in current Congressional revenue-sharing proposals.

In summary, there are two principal reasons which argue why energy-producing states should received much more OCS revenue sharing than proposed recently in Congress:

1. These payments carry a historical symbolic and political association with sharing of federal proprietary rights on the public domain.
2. They compensate state and local governments for the presence of federal tax-exempt property (payments in lieu of taxes concept).

**ALASKA PETROLEUM REVENUES:
THE INFLUENCE OF FEDERAL POLICY**

APPENDIXES

Final Report

Prepared for

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APPENDIX A

ALASKA OIL AND GAS PRODUCTION, PRICES AND LEASE REVENUES

Appendix A contains historical data compiled on Alaska oil and gas production, prices and revenues by region and by landowner. Because there are a large number of different organizations involved in managing some portion of Alaska petroleum lands, production and revenues, there inevitably arise situations of parallel but differing data series for the same item. While we have attempted to form a consistent set of historical data for each series, some differences represent slightly different reporting conventions or definitions of data. We have chosen to include some of these instances of discrepancy in the tables that follow, documenting the source in the notes.

Tables A.1 and A.2 present annual oil and gas production by landowner, region and by field for the North Slope. Tables A.3 and A.4 present weighted average annual prices received for the production shown in tables A.1 and A.2, respectively. Tables A.5 through A.8 summarize lease payments received by public landowners in Alaska by region. Tables A.5 and A.6 include federal revenues received for leases on the Outer Continental Shelf and in the National Petroleum Reserve Alaska, where there has as yet been no commercial production.

Tables A.9, A.10, and A.11 show the historical value of taxable petroleum production and exploration property as assessed by the State of Alaska and the calculation of estimated property taxes paid on this property. As one might expect, all of the production and most of the exploration property is located either in the Kenai Peninsula Borough (Cook Inlet region) or in the North Slope Borough (North Slope region).

BASIC DATA SOURCE GUIDE

<u>SOURCE</u>	<u>ABBREVIATION</u>
Alaska Department of Natural Resources Division of Management, Revenue Section ¹	DNR, Div. of Management
Alaska Department of Natural Resources, Division of Oil and Gas ²	DNR, DOG
Alaska Department of Natural Resources, Division of Oil, and Gas, Public Information Office	DNR, DOG, Public Information Office
Alaska Department of Natural Resources, Division of Oil and Gas, Royalty Accounting Section	DNR, DOG, Royalty Accounting
Alaska Department of Revenue, Division of Petroleum Revenue	DOR, Division of Petroleum Revenue
Alaska Oil and Gas Conservation Commission ³	AOGCC
American Petroleum Institute, <u>Basic Petroleum Data Book</u> , 1983	American Petroleum Institute
U.S. Department of the Interior, Bureau of Land Management, Data Processing	USDOI, BLM, Data Processing
U.S. Department of the Interior, Minerals Management Service ⁴	USDOI, MMS

¹Formerly Division of Land and Water Management, Administrative Revenue Unit.

²Formerly the Division of Minerals and Energy Management.

³Formerly the Department of Natural Resources, Division of Oil and Gas Conservation.

⁴Includes federal lease revenue accounting functions, formerly located under the U.S. Geological Survey, Conservation Division.

TABLE A.1.
ALASKA OIL PRODUCTION
(MILLION BARRELS)

	COOK INLET			NORTH SLOPE				TOTAL NORTH SLOPE	OTHER STATE	FEDERAL OCS	TOTAL ALASKA
	FEDERAL LEASES	STATE LEASES	TOTAL COOK INLET	PRUDHOE BAY	KUPARUK	LISBURN	NPRA				
1959	0.21	0.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19
1960	0.56	0.00	0.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.56
1961	6.30	0.00	6.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.33
1962	10.26	0.00	10.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.26
1963	10.74	0.00	10.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.74
1964	11.05	0.00	11.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.06
1965	11.10	0.00	11.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.13
1966	11.71	2.65	14.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.36
1967	12.98	16.15	29.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.13
1968	13.62	52.58	66.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.20
1969	13.15	60.80	73.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.95
1970	12.41	71.21	83.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	83.62
1971	11.47	68.02	79.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79.49
1972	8.90	63.99	72.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	72.89
1973	10.48	61.83	72.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	72.32
1974	10.14	60.45	70.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.60
1975	9.08	60.74	69.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	69.83
1976	7.89	55.49	63.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.40
1977	6.26	50.23	56.44	112.69	0.00	0.00	0.00	112.76	0.00	0.00	169.20
1978	5.11	45.45	50.45	396.65	0.00	0.00	0.00	398.17	0.00	0.00	448.62
1979	4.55	38.87	43.05	468.41	0.00	0.00	0.00	467.00	0.00	0.00	511.33
1980	3.94	32.39	36.28	555.41	0.00	0.00	0.00	555.61	0.00	0.00	591.65
1981	3.10	28.48	31.87	555.29	1.09	0.00	0.00	556.48	0.00	0.00	587.34
1982	3.14	24.59	27.87	559.27	32.36	0.21	0.00	591.51	0.00	0.00	618.91
1983	3.19	21.75	24.94	560.79	39.85	0.10	0.00	603.76	0.00	0.00	625.53

NOTES TO TABLE A.1

Column 1: SOURCE: US Department of Interior, MMS. 1983 figure from AOGCC.

Column 2: derived by multiplying Alaska state royalty share by 8. SOURCE: DNR, DOG, Royalty Accounting.

Column 3: SOURCE: 1959-1976, American Petroleum Institute, Basic Petroleum Data Book (includes lease condensate); 1977-1982, DNR, DOG, Royalty Accounting; 1983, sum of Columns 1 and 2.

Columns 4-6, 8: SOURCE: DNR, DOG, Royalty Accounting.

Column 11: SOURCE: American Petroleum Institute (includes lease condensate), except 1983 figure from AOGCC.

TABLE A.2.
ALASKA GAS PRODUCTION
(BILLION CUBIC FEET)

	COOK INLET			NORTH SLOPE				TOTAL NORTH SLOPE	OTHER STATE	FEDERAL OCS	TOTAL ALASKA
	FEDERAL LEASES*	STATE LEASES	TOTAL COOK INLET	PRUDHOE BAY	KUPARUK	LISBURNE	NPRA				
1959	0.00		0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13
1960	0.01		0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.25
1961	0.26		0.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.63
1962	1.33		2.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.18
1963	5.99		4.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.50
1964	0.93		6.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.24
1965	4.24		7.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.26
1966	22.76		11.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.27
1967	26.94		14.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.44
1968	33.18		17.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.34
1969	43.62		50.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.86
1970	59.47		111.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	111.58
1971	52.50	35.25	121.62	0.00	0.00	0.00	0.60	0.00	0.00	0.00	121.62
1972	56.28	35.53	125.60	0.00	0.00	0.00	0.70	0.00	0.00	0.00	125.60
1973	52.85	34.90	131.01	0.00	0.00	0.00	0.70	0.00	0.00	0.00	131.01
1974	50.94	35.28	128.93	0.00	0.00	0.00	0.80	0.00	0.00	0.00	128.93
1975	58.01	38.90	160.27	0.00	0.00	0.00	0.80	0.00	0.00	0.00	160.27
1976	60.58	40.25	166.07	0.00	0.00	0.00	0.80	0.00	0.00	0.00	166.07
1977	63.70	42.34	153.01	1.97	0.00	0.00	0.90	1.96	0.00	0.00	187.89
1978	80.20	46.52	163.50	7.26	0.00	0.00	0.90	7.18	0.00	0.00	203.09
1979	78.99	55.20	168.35	8.93	0.00	0.00	0.90	8.97	0.00	0.00	220.75
1980	81.37	56.03	160.39	11.06	0.00	0.00	1.00	10.89	0.00	0.00	230.59
1981	88.77	72.81	176.68	11.52	0.00	0.00	1.00	11.56	0.00	0.00	242.56
1982	93.50	81.60	186.97	12.09	0.10	0.00	1.25	12.98	0.00	0.00	
1983		74.52		13.46	0.14	0.00	1.23	12.95	0.00	0.00	

*EXCLUDES LAND CONVEYED TO COOK INLET REGION, INCORPORATED

NOTES TO TABLE A.2

Column 1: SOURCE: US Dept of Interior, MMS.

Columns 2, 4-6: SOURCE: DNR, DOG, Royalty Accounting.

Column 3, 8: 1959-1976, includes gas used on lease for fuel. SOURCE: American Petroleum Institute (represents gross production net of reinjection and gas vented and flared). 1977-1983, excludes gas used on lease for fuel. Sum of taxable production for Alaska severance taxes (Alaska DOR, DPR) and royalty production (Alaska DNR, DOG, Royalty Accounting and US Dept of Interior, MMS). Barrow gas fields not considered marketed or taxable production.

Column 11: Includes gas used on lease for fuel. SOURCE: American Petroleum Institute (represents gross production less gas used for reinjection and quantities vented and flared).

TABLE A.3.
AVERAGE OIL PRICE
(DOLLARS/BBL)

	COOK INLET			NORTH SLOPE		TOTAL NORTH SLOPE	OTHER STATE	FEDERAL OCS	TOTAL ALASKA
	FEDERAL ROYALTY	STATE ROYALTY	TOTAL COOK INLET	STATE LEASES	NPRA				
1959	1.59	-	1.58	-	-	-	-	-	1.58
1960	2.32	-	2.20	-	-	-	-	-	2.20
1961	2.78	-	2.79	-	-	-	-	-	2.79
1962	3.04	-	3.04	-	-	-	-	-	3.04
1963	3.06	-	3.04	-	-	-	-	-	3.04
1964	3.07	-	3.04	-	-	-	-	-	3.04
1965	3.06	-	3.06	-	-	-	-	-	3.06
1966	3.06	-	3.06	-	-	-	-	-	3.06
1967	3.10	-	3.13	-	-	-	-	-	3.13
1968	3.06	-	2.82	-	-	-	-	-	2.82
1969	3.07	-	2.90	-	-	-	-	-	2.90
1970	3.13	-	3.01	-	-	-	-	-	3.01
1971	3.39	3.28	3.24	-	-	-	-	-	3.24
1972	3.37	3.28	3.23	-	-	-	-	-	3.23
1973	3.93	3.55	3.62	-	-	-	-	-	3.62
1974	6.11	4.70	4.92	-	-	-	-	-	4.92
1975	5.41	4.68	5.22	-	-	-	-	-	5.22
1976	5.29	4.77	5.03	-	-	-	-	-	5.03
1977	5.36	4.83	5.26	6.13	-	6.13	-	-	5.84
1978	5.39	5.59	5.59	5.02	-	5.02	-	-	6.02
1979	6.32	6.14	6.05	10.48	-	10.48	-	-	10.74
1980	9.64	8.58	10.06	16.73	-	16.73	-	-	15.63
1981	29.51	29.38	30.05	23.18	-	23.18	-	-	23.63
1982	27.82	28.25	27.79	19.69	-	19.69	-	-	
1983		25.25		17.44	-	17.44	-	-	

Notes: Column 1: Source, U.S. Department of Interior, MMS.

Columns 2, 4, 6: Source, Alaska DNR, DOG, Royalty Accounting.

Column 3: Sources, 1959-1976, American Petroleum Institute, 1977-1982, weighted average of taxable and royalty share prices (Alaska DOR, DPR, Alaska DNR, DOG, Royalty Accounting and U.S. Department of Interior, MMS).

Column 9: Weighted average annual wellhead price, state average; source, American Petroleum Institute.

TABLE A.4.
AVERAGE GAS PRICE
(DOLLARS/MCF)

	COOK INLET			NORTH SLOPE			OTHER STATE	FEDERAL OCS	TOTAL ALASKA
	FEDERAL ROYALTY	STATE ROYALTY	TOTAL COOK INLET	STATE LEASES	NPRA	TOTAL NORTH SLOPE			
1959	0.00	-	0.12	-	-	-	-	-	0.12
1960	0.30	-	0.12	-	-	-	-	-	0.12
1961	0.30	-	0.20	-	-	-	-	-	0.20
1962	0.33	-	0.21	-	-	-	-	-	0.21
1963	0.25	-	0.25	-	-	-	-	-	0.25
1964	0.25	-	0.28	-	-	-	-	-	0.28
1965	0.24	-	0.25	-	-	-	-	-	0.25
1966	0.18	-	0.25	-	-	-	-	-	0.25
1967	0.19	-	0.25	-	-	-	-	-	0.25
1968	0.18	-	0.25	-	-	-	-	-	0.25
1969	0.17	-	0.26	-	-	-	-	-	0.26
1970	0.17	-	0.25	-	-	-	-	-	0.25
1971	0.17	0.20	0.15	-	-	-	-	-	0.15
1972	0.18	0.22	0.15	-	-	-	-	-	0.15
1973	0.18	0.24	0.15	-	-	-	-	-	0.15
1974	0.20	0.28	0.17	-	-	-	-	-	0.17
1975	0.28	0.62	0.30	-	-	-	-	-	0.30
1976	0.32	0.74	0.39	-	-	-	-	-	0.39
1977	0.32	0.78	0.39	1.07	-	1.07	-	-	0.40
1978	0.36	0.70	0.49	1.19	-	1.19	-	-	0.52
1979	0.41	0.81	0.66	1.75	-	1.75	-	-	0.52
1980	0.61	0.69	0.54	1.84	-	1.84	-	-	0.73
1981	0.88	0.95	0.59	1.75	-	1.75	-	-	0.62
1982	1.13	0.39	0.59	1.70	-	1.70	-	-	0.63
1983		0.43		1.80	-	1.80	-	-	

Notes: Column 1: Source, U.S. Department of Interior, MMS.

Columns 2, 4, 6: Source, Alaska DNR, DOG, Royalty Accounting.

Column 3: Sources, 1959-1976, American Petroleum Institute, 1977-1982, weighted average of taxable and royalty share prices (Alaska DOR, DPR, Alaska DNR, DOG, Royalty Accounting and U.S. Department of Interior, MMS).

Column 9: Weighted average annual wellhead price, state average; source, American Petroleum Institute.

TABLE A.5.
BONUS PAYMENTS
(MILLION DOLLARS)

	COOK INLET			NORTH SLOPE		TOTAL NORTH SLOPE	OTHER STATE	FEDERAL OCS	TOTAL ALASKA
	FEDERAL LEASES	STATE LEASES	TOTAL COOK INLET	STATE LEASES	NPRA				
1959	0.00	2.98	2.98	0.00	0.00	0.00	1.04	0.00	4.02
1960	0.00	0.42	0.42	0.00	0.00	0.00	0.02	0.00	0.44
1961	0.00	21.90	21.90	0.00	0.00	0.00	0.51	0.00	22.42
1962	0.00	15.71	15.71	0.00	0.00	0.00	0.00	0.00	15.71
1963	0.00	7.18	7.18	0.00	0.00	0.00	0.00	0.00	7.18
1964	0.00	1.06	1.06	4.38	0.00	4.38	0.18	0.00	5.61
1965	0.00	4.67	4.67	6.15	0.00	6.15	0.00	0.00	10.82
1966	0.00	7.18	7.18	0.00	0.00	0.00	0.00	0.00	7.18
1967	0.00	18.76	18.76	1.47	0.00	1.47	0.01	0.00	20.24
1968	0.00	1.04	1.04	900.04	0.00	0.00	3.01	0.00	4.05
1969	0.00	0.00	0.00	0.00	0.00	900.04	0.00	0.00	900.04
1970	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1971	0.00	0.46	0.46	0.00	0.00	0.00	0.00	0.00	0.46
1972	0.00	2.88	2.88	0.00	0.00	0.00	0.00	0.00	2.88
1973	0.00	25.95	25.95	0.00	0.00	0.00	0.00	0.00	25.95
1974	0.00	1.04	1.04	0.00	0.00	0.00	0.00	0.00	1.04
1975	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1976	0.00	0.00	0.00	0.00	0.00	0.00	0.00	559.84	559.84
1977	0.00	0.00	0.00	0.00	0.00	0.00	0.00	398.47	398.47
1978	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1979	0.00	0.00	0.00	567.39	0.00	567.39	0.16	488.69	1056.24
1980	0.00	0.00	0.00	12.39	0.00	12.39	0.00	109.75	122.14
1981	0.00	5.82	5.82	0.00	0.00	0.00	0.00	4.58	10.40
1982	0.00	1.31	1.31	59.30	53.30	112.60	0.66	2055.63	2170.20
1983	0.00				0.96				

Notes: Columns 1, 5: Source, U.S. Department of Interior, Bureau of Land Management, Data Processing.

Columns 2, 4, 7: Source, Alaska DNR, Division of Management (ISER allocation to region).

Column 8: Source, U.S. Department of Interior, MMS.

TABLE A.6.
RENTAL PAYMENTS
(MILLION DOLLARS)

	COOK INLET			NORTH SLOPE			OTHER STATE	FEDERAL OCS	TOTAL ALASKA
	FEDERAL LEASES	STATE LEASES	TOTAL COOK INLET	STATE LEASES	NPRA	TOTAL NORTH SLOPE			
1959	0.34	0.00	0.34	00.0	0.00	0.00	0.00	0.00	0.34
1960	0.08	0.18	0.26	00.0	0.00	0.00	0.01	0.00	0.27
1961	0.01	0.34	0.35	00.0	0.00	0.00	0.02	0.00	0.37
1962	0.08	1.00	1.07	00.0	0.00	0.00	0.05	0.00	1.12
1963	0.04	0.96	1.00	00.0	0.00	0.00	0.05	0.00	1.06
1964	0.02	0.75	0.77	0.50	0.00	0.50	0.00	0.00	1.27
1965	0.08	1.56	1.64	1.04	0.00	1.04	0.00	0.00	2.68
1966	0.27	1.06	1.33	1.06	0.00	1.06	0.53	0.00	2.93
1967	0.26	1.13	1.39	1.13	0.00	1.13	0.57	0.00	3.09
1968	5.74	1.38	7.12	1.38	0.00	1.38	0.69	0.00	9.19
1969	0.41	0.79	1.20	1.58	0.00	1.58	0.79	0.00	3.57
1970	0.30	0.72	1.02	1.44	0.00	1.44	0.72	0.00	3.18
1971	0.21	0.76	0.97	1.52	0.00	1.52	0.76	0.00	3.26
1972	0.35	0.75	1.10	1.49	0.00	1.49	0.75	0.00	3.34
1973	0.29	0.83	1.12	1.67	0.00	1.67	0.03	0.00	2.83
1974	0.34	0.90	1.24	1.80	0.00	1.80	0.90	0.00	3.94
1975	0.31	0.86	1.17	1.71	0.00	1.71	0.86	0.00	3.74
1976	0.29	0.69	0.98	1.39	0.00	1.39	0.69	1.23	4.29
1977	0.01	0.67	0.68	1.34	0.00	1.34	0.67	2.83	5.52
1978	0.00	0.55	0.55	1.10	0.00	1.10	0.55	2.83	5.03
1979	0.00	0.52	0.52	1.02	0.00	1.03	0.52	2.32	4.39
1980	0.29	1.39	1.68	2.77	0.00	2.77	1.39	2.23	8.06
1981	0.01	1.65	1.66	3.31	0.00	3.31	1.65	1.88	8.50
1982	2.50	0.81	3.31	1.62	2.72	4.34	0.81	3.32	11.78
1983	2.30				2.65				

Notes: Columns 1, 5: Source, U.S. Department of Interior, Bureau of Land Management, Data Processing.

Columns 2, 4, 7: Source, Alaska DNR, Division of Management (ISER allocation to region).

Column 8: Source, U.S. Department of Interior, MMS.

TABLE A.7.
OIL ROYALTIES
(MILLION DOLLARS)

	COOK INLET			NORTH SLOPE				TOTAL NORTH SLOPE	OTHER STATE	FEDERAL OCS	TOTAL ALASKA
	FEDERAL LEASES	STATE LEASES	TOTAL COOK INLET	PRUDHOE BAY	KUPARUK	LISBURN	NPRA				
1959	0.02	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
1960	0.11	0.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11
1961	1.80	0.00	1.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.80
1962	3.28	0.00	3.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.28
1963	3.48	0.04	3.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.52
1964	3.61	0.08	3.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.69
1965	3.55	0.10	3.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.64
1966	3.74	0.94	4.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.68
1967	4.44	3.52	7.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.95
1968	5.22	14.23	19.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.45
1969	5.05	17.40	22.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.44
1970	4.86	22.15	27.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.01
1971	4.86	27.89	32.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.77
1972	3.75	26.22	29.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.97
1973	5.14	27.46	32.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.65
1974	7.74	35.52	43.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.35
1975	6.14	35.51	41.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.68
1976	5.22	33.10	38.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.33
1977	4.19	30.35	34.56	78.73	0.00	0.00	0.00	78.73	0.00	0.00	113.29
1978	3.44	31.79	35.24	223.71	0.00	0.00	0.00	223.71	0.00	0.00	258.95
1979	3.60	29.82	33.44	582.27	0.00	0.00	0.00	582.27	0.00	0.00	615.71
1980	4.75	34.74	39.51	1115.64	0.00	0.00	0.00	1115.64	0.00	0.00	1155.15
1981	11.42	104.61	116.03	1568.27	2.73	0.00	0.00	1571.00	0.00	0.00	1687.02
1982	10.92	86.83	97.76	1351.70	70.99	0.50	0.00	1423.18	0.00	0.00	1520.94
1983		68.66		1191.38	78.99	0.22	0.00	1270.59	0.00	0.00	

NOTES: Column 1: Source, U.S. Department of Interior, MMS.
Columns 2, 4, 5, 6, 8: Alaska DNR, DOG, Royalty Accounting

TABLE A.8.
GAS ROYALTIES
(MILLION DOLLARS)

	COOK INLET			NORTH SLOPE							
	FEDERAL LEASES*	STATE LEASES	TOTAL COOK INLET	PRUDHOE BAY	KUPARUK	LISBURNE.	NPRA	TOTAL NORTH SLOPE	OTHER STATE	FEDERAL OCS	TOTAL ALASKA
1959	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1960	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1961	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
1962	0.03	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03
1963	0.10	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10
1964	0.04	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04
1965	0.09	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09
1966	0.35	0.00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.35
1967	0.43	0.00	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.43
1968	0.53	0.24	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77
1969	0.70	0.39	1.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.09
1970	1.29	0.76	2.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.04
1971	1.13	0.90	2.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.02
1972	1.23	0.96	2.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.20
1973	1.19	1.05	2.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.24
1974	1.31	1.23	2.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.54
1975	2.01	3.03	5.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.04
1976	2.40	3.73	6.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.13
1977	2.58	4.13	6.71	0.26	0.00	0.00	0.00	0.26	0.00	0.00	6.97
1978	3.59	4.05	7.64	1.08	0.00	0.00	0.00	1.08	0.00	0.00	8.73
1979	4.01	5.59	9.60	1.37	0.00	0.00	0.00	1.37	0.00	0.00	10.97
1980	6.24	4.83	11.08	1.83	0.00	0.00	0.00	1.83	0.00	0.00	12.91
1981	9.75	8.60	18.35	2.17	0.00	0.00	0.00	2.17	0.00	0.00	20.52
1982	13.21	4.03	17.24	2.57	0.03	0.00	0.00	2.60	0.00	0.00	19.83
1983		4.02		2.96	0.05	0.00	0.00	3.01	0.00	0.00	

*EXCLUDES LAND CONVEYED TO COOK INLET REGION, INCORPORATED

NOTES: Column 1: Source, U.S. Department of Interior, MMS.

Columns 2, 4, 5, 6, 8: Alaska DNR, DOG, Royalty Accounting

TABLE A.9.
 ASSESSED VALUES AND EFFECTIVE TAX RATES FOR OIL AND GAS PROPERTY
 (thousands of current dollars)

Year	North Slope Borough			Kenai Peninsula Borough			Yakutat ^a		
	Assessed Value	Local Credit	Tax Rate (mills)	Assessed Value	Local Credit	Tax Rate (mills)	Assessed Value	Local Credit	Tax Rate (mills)
1975	424,417	5,220	12.30	403,603	2,640	6.54	0	0	-
1976	1,520,251	15,659	10.30	457,274	3,041	6.65	0	0	-
1977	3,304,837	24,852	7.52	460,401	2,910	6.32	3,887	51	13.10
1978	4,456,311	32,488	7.29	452,631	2,556	5.65	3,213	44	13.70
1979	4,810,888	49,801	10.35	445,727	1,433	3.22	2,640	36	13.70
1980	5,450,597	55,974	10.27	499,955	1,834	3.67	1,944	27	13.70
1981	6,297,617	105,151	16.70	562,863	1,570	2.79	2,033	28	13.70
1982	7,722,400	126,802	16.42	578,500	1,446	2.50	2,060	28	13.70

^aProperty tax revenues taken assumed to be entirely exploration related.

SOURCES: Petroleum Property Assessor, Department of Revenue, Division of Petroleum Revenue.

Alaska Department of Community and Regional Affairs, Division of Local Government Assistance. Alaska Taxable.

TABLE A.10.
HISTORICAL ASSESSED VALUE OF ALASKA OIL AND GAS PROPERTY^a
(thousands of current dollars)

<u>Property Type/Area^b</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1982</u>
Pipeline Property									
Kenai Peninsula Borough	37,601	40,201	53,325	54,846	50,226	47,422	44,046	46,455	45,000
North Slope Borough	54,673	191,664	728,923	1,420,749	1,948,703	1,727,939	2,055,866	2,117,825	2,114,600
Other/Statewide	165,376	453,829	2,628,487	4,700,309	6,151,297	6,672,061	6,194,134	6,248,125	6,067,500
Production Property									
Kenai Peninsula Borough	282,904	353,486	386,743	388,548	380,705	376,899	428,058	495,317	496,700
North Slope Borough									
Sadlerochit	152,283	194,070	706,613	1,781,406	2,375,106	2,878,127	3,141,438	3,716,788	
Kuparuk	0	0	0	0	0	26,000	53,755	104,421	5,200,000
Other North Slope	4,700	8,000	20,000	31,600	42,000	50,000	50,500	79,451	
Other/Statewide	205	621	790	3,944	4,101	4,640	4,892	7,310	9,700
Exploration/Other									
Kenai Peninsula Borough	2,308	9,916	17,219	17,008	21,940	21,406	27,852	21,091	36,800
North Slope Borough	14,767	30,683	64,715	71,082	90,502	128,822	149,038	279,132	407,800
Yakutat ^c	0	0	0	3,887	3,213	2,640	1,944	2,033	2,060
Other/Statewide	1,799	5,820	15,808	18,868	9,432	10,491	14,112	52,686	30,240

^aFull and true value of all taxable property as defined by AS 43.56.

^bFor the Kenai Peninsula Borough, the valuation of oil producing property prior to 1974 was \$265,000 (1971), \$283,000 (1972), and \$304,000 (1973). Source: D.E. Thomas, Director of Assessing Kenai Peninsula Borough.

^cEntire value of petroleum property in Yakutat assumed to be exploration property.

SOURCE: Petroleum Property Assessor, Department of Revenue, Division of Petroleum Revenue.

TABLE A.11.
PROPERTY TAX REVENUES FROM OIL AND GAS PRODUCTION AND EXPLORATION PROPERTY
(thousands of current dollars)

	<u>1971</u>	<u>1972</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1982</u>
Assessed Valuation ^a	0	0	0	458,966	602,596	1,211,888	2,316,343	2,926,999	3,499,085	3,871,589	4,758,229	6,183,300
Gross Tax Liability ^b	0	0	0	9,179	12,052	24,238	46,327	58,540	69,982	77,432	95,165	123,666
Local Revenue ^c												
KPB	2,200	2,264	2,250	1,996	2,377	2,686	2,563	2,274	1,281	1,672	1,441	1,334
NSB	0	0	*	2,233	2,863	8,151	14,168	13,736	31,914	34,864	69,803	92,080
Yakutat	0	0	0	0	0	0	51	44	36	27	28	28
State Revenue ^d	0	0	0	4,950	6,812	13,401	29,545	42,486	36,751	40,871	23,893	30,224

* Not available.

^aTable A.10. Note that the state property tax was not in effect prior to 1974.

^bCalculated as two percent (20 mills) of the full and true value of all production and exploration property (i.e., exclusive of pipeline property).

^cLocal production and exploration property tax values for the Kenai Peninsula Borough (KPB) and North Slope Borough (NSB) derived by applying effective borough-wide tax rates for all oil and gas property to the assessed value for oil and gas property exclusive of pipeline property. Tables A.9 and A.10. Values for 1974 estimated for KPB using effective rate of 7.0 mills and for NSB using effective tax rate of 13.0 mills. Values for Yakutat from Table A.9 (see footnote).

^dState revenues equal to the difference between gross tax liability and local revenues. Values include negligible amounts of production and/or exploration property tax revenues that accrued to local governments other than KPB, NSB, or Yakutat.

APPENDIX B

HISTORICAL COSTS OF OIL AND GAS EXPLORATION AND DEVELOPMENT IN ALASKA

1.0. Introduction

The historical costs associated with Alaska oil and gas development can be considered as the total of all expenditures for (1) geological and geophysical exploration, (2) drilling and field development, and (3) production, including operation and maintenance. For the purposes of this study, oil and gas development is defined exclusive of pipeline and refinery expenditures. Where published cost estimates were found, they are reported below. Where insufficient data were available, estimates of past costs were derived on the basis of reported levels of activity such as geological and geophysical crew-months of field work or footage of drilling.

Only one source was found to report total statewide historic industry costs as shown in Table B.1. Costs for lease acquisition such as over-the-counter lease application fees, bonus bids, and rental payments are treated separately.

2.0. Exploration Costs

Exploration costs can be defined to include all geological and geophysical exploration expenses, including seismic, gravity, and magnetic surveys, together with the cost of data processing and interpretation. Data on actual expenditures associated with Alaska exploration effort is generally not available, although some limited information is available from the Alaska Department of Natural Resources (DNR) and the Alaska Department of Revenue (DOR). In order to derive more comprehensive historical exploration cost estimates, Alaska exploration activity levels were documented using several sources including the annual reports of the American Association of Petroleum Geologists (AAPG) and the Society of

TABLE B.1.
ESTIMATED COSTS FOR EXPLORATION, DEVELOPMENT,
AND PRODUCTION OF OIL AND GAS IN ALASKA
(millions of dollars)

Activity	1963	1964	1965	1966	1967	1968
Exploration ^a	54.0	61.0	66.0	66.4	74.6	63.6
Development Drilling	4.6	0.7	5.3	17.6	37.2	66.4
Production	1.6	1.8	19.3	55.8	71.8	28.7
Refinery Construction ^b	5.6	2.2	2.0	6.5	34.8	55.8
Total, Exclusive of Refinery Costs	60.2	63.5	90.6	139.8	183.6	158.7

^aIncludes exploratory drilling costs as well as geological and geophysical survey activity together with administration expenses; does not include costs for lease acquisition.

^bIncludes operation and maintenance.

SOURCES: State of Alaska Department of Natural Resources, Division of Mines and Minerals (Annual Reports 1963-1967); State of Alaska, Department of Natural Resources, Division of Oil and Gas (Annual Report 1968).

Exploration Geophysicists (SEG). The data for exploration activity, as measured in yearly crew-months of field work, was then used as the basis for developing an annual series of estimated historical exploration costs in Alaska 1958-1980. A brief review of published historical exploration cost data available from DNR and DOR is provided below, followed by a description of the data used to derive the annual series of estimated historical exploration costs used in our analysis.

An estimate of statewide exploration costs for the two-year period 1960-1961 is available from the annual reports of the DNR Division of Mines and Minerals¹ as shown in Table B.2. An estimate of past costs for geological and geophysical work done in the Cook Inlet Basin 1959-1974 is available from the DOR Petroleum Revenue Division (1975) based on information supplied by the Alaska Oil and Gas Association (AOGA).

TABLE B.2.
EXPLORATION COSTS^a
(millions of dollars)

Year	Geologic	Seismic	Grav-Mag	Total
1960	1.68	3.62	0.13	5.43
1961	1.91	6.92	0.50	9.33

^aThis source also reported costs associated with exploratory drilling as \$8.28 million in 1960 and \$15.08 million in 1961.

SOURCE: Alaska Department of Natural Resources, Division of Mines and Minerals, annual reports 1960-1961.

The DOR report observed: "Information supplied by [AOGA] suggests that geophysical and geological costs have together run about 110 percent of bonus bids for the Cook Inlet Basin." To account for the timing of these exploration costs, the DOR study estimated that 110 percent of the cost of bonus bids in a given year had been incurred two years earlier as costs for geologic and geophysical exploration in Cook Inlet as shown in Table B.3. This same data series for exploration costs was used in a subsequent study by Erickson and Latham (1976). Unfortunately, the practice of collecting data on industry costs has been discontinued by AOGA, and no information on past costs is currently available.

In order to develop a more comprehensive and historically accurate account of the timing of geological and geophysical exploration costs, the level of exploration activity in Alaska was documented as measured in crew-months of field activity. The most comprehensive source of data for yearly exploration activity is the annual review of the American Association of Petroleum Geologists (AAPG). This annual account of exploration activity reports detailed information on petroleum industry activities including the number of crew-months of geological and geophysical exploration effort on a regional basis. The AAPG data for Alaska is summarized in Table B.4. A separate estimate of Alaska geophysical activity (seismic, gravity, and magnetics) is available from an annual survey conducted by the Society of Exploration Geophysicists (SEG). While the SEG survey emphasizes the distinction between onshore and marine geophysical work, the data is collected on a statewide basis disallowing the possibility of allocating costs to different regions such as Cook Inlet or the North Slope. The SEG survey results are shown in Table B.5.

TABLE B.3.
DOR ESTIMATE OF GEOLOGICAL AND GEOPHYSICAL
EXPLORATION COSTS IN THE COOK INLET
BASIN, 1959-1974
(millions of dollars)

Year	Exploration Costs ^a
1959	21.97
1960	17.19
1961	7.90
1962	1.16
1963	5.14
1964	7.89
1965	14.10
1966	3.36
1967	0
1968	0
1969	0.50
1970	3.17
1971	27.30
1972	1.14
1973	1.00
1974	1.00

^aCosts assumed to be 110 percent of total bonus bids for Cook Inlet region with exploration expenditures accounted for two years prior to lease sale. See text for additional explanation.

SOURCE: Department of Revenue, Division of Petroleum Revenue (1975).

TABLE B-4.
EXPLORATION ACTIVITY IN ALASKA
BY GEOGRAPHIC REGION^a
(crew-months)

Year	Cook Inlet			North Slope ^b			Other Areas ^c		
	Geology	Seismic	Grav-Mag	Geology	Seismic	Grav-Mag	Geology	Seismic	Grav-Mag
1958	38.0	36.0	8.5	3.0	0	0	75.0	3.0	3.5
1959 ^d	16.0	61.0	0	14.0	0	0	92.0	27.25	1.0
1960	21.25	27.5	1.75	21.25	0	0	30.0	11.0	3.0
1961	10.5	37.75	5.5	28.5	0	0	19.0	31.0	8.75
1962	3.75	60.25	7.0	12.75	6.5	6.0	19.25	14.50	3.5
1963	2.25	60.0	4.0	29.0	29.25	3.5	33.0	20.75	5.0
1964	2.25	31.5	3.0	19.0	53.5	11.0	32.75	10.0	6.0
1965	0.5	22.25	3.75	15.5	26.75	1.5	18.75	11.25	4.75
1966	5.0	58.5	*	10.1	2.75	*	30.2	18.25	*
1967	6.0	42.5	3.5	3.0	0	0	30.0	24.0	2.0
1968	1.0	33.0	*	12.0	24.0	*	22.0	23.0	*
1969	0	6.0	5.0	20.0	101.0	0	16.0	23.5	3.5
1970	1.0	6.0	*	20.0	96.0	*	25.0	26.0	*
1971	3.0	7.0	*	20.0	21.0	*	27.5	16.0	*
1972	1.0	9.5	*	13.4	8.0	*	22.9	24.5	*
1973	2.6	8.1	*	6.5	24.4	*	17.3	24.4	*
1974	2.8	18.8	*	7.2	54.3	*	32.0	53.2	*
1975	4.0	5.8	*	6.0	82.9	*	23.4	102.6	*
1976	4.3	15.0	*	3.4	22.6	*	15.2	91.3	*
1977	2.1	8.61	*	6.8	14.4	*	20.3	27.0	*
1978	4.1	8.0	*	4.2	19.7	*	12.2	15.7	*
1979	0.4	14.9	*	3.8	19.7	*	6.7	17.6	*
1980	0.3	30.5	*	6.8	25.14	*	4.1	38.8	*
1981	0	12.59	*	9.67	45.38	*	7.67	56.91	*

*Not available. AAPG data gives only two categories of crew-month activity: geologic and geophysical. No distinction is made between seismic geophysical work and the less costly gravity and magnetics work.

^aGeological and geophysical activity by private industry (exclusive of work by the federal or state government). No clear distinction is made between onshore and offshore work prior to 1976. Categories of work include surface geological investigations (geologic), seismological surveys (seismic), and gravity and magnetics surveys (grav-mag).

^bNorth Slope onshore areas only (i.e., foothills and coastal plain).

^cIncludes all geologic and geophysical exploration activity by private industry outside the Cook Inlet and North Slope regions. Includes exploratory work in the Beaufort Sea.

^dGeologic crew-months for 1959 estimated from data provided on the number of companies operating in the area. The number of companies reported as active was multiplied by a factor of 2 in order to reflect two crew-months of exploration per company.

SOURCE: AAPG, Annual Activity Reports, 1958-81.

TABLE B.5.
CREW-MONTHS OF
ALASKA EXPLORATION ACTIVITY^a
(crew-months)

<u>Year</u>	<u>Onshore</u>		<u>Marine</u>		<u>Total</u>	
	<u>Seismic</u>	<u>Grav-Mag</u>	<u>Seismic</u>	<u>Grav-Mag</u>	<u>Seismic</u>	<u>Grav-Mag</u>
1959	*	*	*	*	97	10
1960*	*	*	*	*	*	*
1961	*	*	*	*	71	12
1962	*	*	*	*	67	1
1963	*	*	*	*	106	3
1964	*	*	*	*	100	13
1965	*	*	*	*	67	4
1966	*	*	*	*	94	0
1967	34	0	31	0	65	0
1968	80	0	26	2	106	2
1969	155	1	22	0	177	1
1970	84	14	15	5	99	19
1971	40	3	22	2	62	5
1972	41	20	22	1	63	21
1973	41	6	23	1	64	7
1974	129	*	54	*	183	*
1975	101	*	76	*	177	*
1976	54	*	75	*	129	*
1977	24	*	10	*	34	*
1978	16	*	*	*	*	*
1979	30	*	*	*	*	*
1980	37	*	*	*	*	*

*Not available.

^aThe SEG survey discontinued reporting of nonseismic crew activity on a state-by-state basis in 1974. The first year the survey distinguished between onshore and marine work was 1967.

SOURCE: Society of Exploration Geophysicists Annual Activity Reports.

The unit costs of geological and geophysical exploration activities (dollars per crew-month of activity) have been given detailed consideration by the National Petroleum Council (1981) in its study of U.S. arctic oil and gas development potential. Additional data is available from Mead (1980) and Beck (1977).

The NPC study observed that it is generally far more expensive to conduct exploration in arctic Alaska than in the "Lower 48" states. While each exploration project should be costed out on a site-specific basis, general unit cost estimates were developed as part of the study as shown in Table B.6. It should be emphasized that these estimates were developed by the NPC for the purpose of evaluating prospective arctic oil and gas developments. The costs shown, therefore, reflect expenses for geological and geophysical work on the North Slope and in the frontier OCS areas of the Beaufort Sea, Chukchi Sea, and Bering Sea. While the actual historical costs attributable to any one specific exploration program for a given year may differ from the NPC estimated unit costs, the values shown in Tables B.6 and B.7 provide a basis for making historical exploration cost estimates.

TABLE B.6.
GEOLOGICAL AND GEOPHYSICAL
EXPLORATION COSTS^a
(1981 dollars)

<u>Activity</u>	<u>Area</u>	<u>Cost/ Crew-Month (\$000s)</u>	<u>Cost/Mile (\$000s)</u>
Geologic	North Slope	100-125	NA
Seismic ^b	North Slope	1300-2700	12-45
	Bering Sea	3000-4000	1.5-2
	Beaufort Sea	850-2400	8-12
	Chuckchi	850-5000	2-12
Gravity-Magnetic	All Areas	100-250	NA

NA - Not applicable.

^aThe cost of exploration programs as shown include only "on-site data gathering" and does not include additional costs of data processing and interpretation. Cost data shown prepared for purposes of evaluating arctic exploration expenses on the North Slope and in the frontier OCS areas of the Bering Sea, Beaufort Sea, and Chuckchi Sea (see text).

^bRange of costs for seismic work varies depending upon assumptions regarding the efficiency of operation (miles/month). See Table B.7.

SOURCE: National Petroleum Council, Exploration Task Group Working Paper #4 (1981).

TABLE B.7.
COSTS OF REFLECTION SEISMIC SURVEY WORK
NPC ESTIMATES
(1981 dollars)

<u>NPC Region/Location</u>	<u>Cost/Month</u>	<u>Miles/Month</u>	<u>Cost/Mile</u>
Region I: North Slope			
● Coastal	\$1.3-1.76 million	110	\$12,000-16,000
● Foothills	\$1.5-2.7 million	60	\$25,000-45,000
Region II: Bering Sea	\$3-4 million	2000	\$1,500-2,000
Region III: Beaufort/Chuckchi Sea			
● Hard water	\$0.85-1.2 million	100	\$8,500-12,000
● Shallow marine	\$1.6-2.4 million	200	\$8,000-12,000
● Beaufort	\$12.75-15 million	1500	\$8,500-10,000
● Chuckchi	\$4-5 million	2000	\$2,000-2,500

SOURCE: National Petroleum Council, Exploration Task Group Working Paper No. 4 (1981).

A separate estimate of geophysical exploration costs is available from Mead (1980) as part of a study for USGS on OCS lease competition and performance in the Gulf of Mexico. As part of that study, Mead reported geophysical exploration costs based primarily upon data collected by the Society of Exploration Geophysicists plus additional data gathered directly from seven of the major Gulf of Mexico offshore oil producers. The geophysical exploration costs for the Gulf of Mexico are summarized in Table B.8.

Beck examined marine geophysical costs as part of a study by Arthur D. Little Co. (ADL) for the Bureau of Land Management. The ADL report developed an index of marine geophysical data acquisition costs per line mile of effort in 1975. The index is shown in Table B.9. As indicated by these figures, because of the severe ice conditions, geophysical work in the Beaufort Sea is far more expensive than elsewhere. For the purpose of comparison, estimated national average geophysical exploration costs are shown in Table B.10.

A note of caution is appropriate with regard to the use of the statistic "crew-month." As far back as 1906, in the SEG annual activity report it was observed: "One area in which we are not satisfied is in 'months' as a unit for quantity of work. Fast marine operations, where 24-hour days are often the rule, will produce a thousand miles of line and more per month. When this quantity of work is compared to a land crew where 50 miles is a good month's work, the shakiness of our reporting system is really noticeable. However, until some better system of universal acceptance is available, we will continue to use 'months' as a basic statistic."

A year later, the SEG annual activity report repeated concerns about the "crew-month" as a measure of activity: "Once again we refer to

TABLE B.8.
EXPLORATION COSTS, GULF OF MEXICO OCS AREAS
1950 - 1969
(current dollars)

<u>Year</u>	<u>Cost per Crew Month (Marine Seismic)</u>
1950	\$120,000
1951	125,000
1952	130,000
1953	135,000
1954	140,000
1955	145,000
1956	150,000
1957	150,000
1958	150,000
1959	155,000
1960	155,000
1961	160,000
1962	165,000
1963	170,000
1964	180,000
1965	200,000
1966	180,000
1967	120,000
1968	130,000
1969	155,000

SOURCE: Mead, Appendix 2 (1980).

TABLE B.9.
INDEX OF MARINE GEOPHYSICAL COSTS PER LINE MILE
FOR ACQUISITION OF DATA
1975

<u>Area</u>	<u>Cost Index</u>
Gulf of Mexico	100
Atlantic Coast	127
Pacific Coast	127
Gulf of Alaska	132
Chuckchi Sea	127
Bering Sea	132
Beaufort Sea ^a	1,136

^aBeaufort Sea costs are assumed to be the same as average Canada land costs because surveys on ice tend to be more like land surveys than like sea surveys.

SOURCE: Beck (1977).

TABLE B.10.
ESTIMATED NATIONAL AVERAGE COSTS
OF EXPLORATION ACTIVITY DOLLARS PER CREW-MONTH^a
(thousands of dollars)

<u>Year</u>	<u>Land</u>	<u>Marine</u>	<u>Total</u>
1964	*	*	48
1965	35	180	56
1966	*	*	52
1967	40	120	48
1968	45	130	49
1969	65	155	66
1970	50	158	53
1971	47	170	51
1972	59	130	60
1973	71	191	82
1974	84	213	97
1975	93	241	109
1976	107	216	117

*Not available.

^aAs reported by the SEG annual activity survey or derived by dividing total data gathering costs by total crew months of activity. Data acquisition costs only (no processing or interpretation).

SOURCE: Society of Exploration Geophysicists, Geophysics (annual activity reports 1964-1976).

the inadequacy of crew-months in reporting [marine seismic activity] We continue to give it a value of 10X land work as a measure of useful work."

During the mid-1970s, the line mile (and costs in \$/line mile) emerged as a new standard of measure for exploration activity. As a measure of costs, the line mile can accommodate differences in efficiency associated with land versus marine operations.

For the purposes of estimating historical activity and costs, however, the only consistently gathered statistic is crew-months of activity. Moreover, the only data available on a state-by-state basis is crew-months of activity.

A substantial component of exploration expenditures beyond raw geological and geophysical (G and G) data acquisition are those costs associated with data processing and interpretation. According to Mead (1980), the costs of geological data processing and interpretation "have risen from about 25 percent of data acquisition costs (1950-1953) to over 100 percent of acquisition costs (since 1975), reflecting the improvements in computer technology and sophistication of mathematical and other modeling of geological information." Mead emphasizes the "rapid rise since 1966 of processing/interpretation costs as a proportion of total 'G and G' costs." Estimates of processing and interpretation costs as a percentage of data acquisition costs are shown in Table B.11.

3.0 Drilling and Development Costs

Statistics regarding the amount of exploratory and development drilling that has taken place in Alaska are currently kept by the Alaska Oil and Gas Conservation Commission and formerly by the Alaska Department of Natural Resources. Additional data is available from the annual reports of the American Association of Petroleum Geologists. An annual account of statewide exploration, development, and service well drilling is shown in Table B.12.

TABLE B.11.
ESTIMATES OF PROCESSING AND INTERPRETATION COSTS
AS A PERCENTAGE OF DATA ACQUISITION COSTS^a
(percent)

<u>Year</u>	<u>Land</u>	<u>Marine</u>
1959	*	35
1960	*	35
1961	*	35
1962	*	40
1963	*	40
1964	*	40
1965	*	30
1966	*	30
1967	*	50
1968	30	60
1969	30	60
1970	*	*
1971	*	*
1972	30	100
1973	30	100
1974	30	100
1975	30	100
1976	30%	110%

*Not available.

^aPercentages based on unit cost of \$/crew-month as 100 percent.

SOURCE: Mead (1980) and the Society of Exploration Geophysicists Annual Activity Reports.

TABLE B.12.
ALASKA DRILLING STATISTICS
(feet of well depth)

<u>Year</u>	<u>Exploration</u>	<u>Development</u>	<u>Service</u>	<u>Total</u>
1959	75705	62197	0	137902
1960	93749	166592	0	260341
1961	197499	302989	0	500488
1962	290976	84421	0	375397
1963	135248	80337	0	215585
1964	177110	2363	0	179473
1965	187135	81236	0	268371
1966	383972	162513	0	546485
1967	317986	588448	0	906134
1968	172444	999998	0	1172442
1969	583518	640096	0	1223614
1970	214111	504920	0	719031
1971	69637	264949	0	334586
1972	105827	191505	0	297332
1973	92966	186841	0	279807
1974	115826	241644	0	357470
1975	208303	406405	61843	676551
1976	133167	579001	88548	800716
1977	166259	487814	26943	681016
1978	176335	580134	105688	862157
1979	155335	786940	81659	1023934
1980	158373	1186009	9500	1353882
1981	256428	1557668	53280	1867376
1982	147403	1952761	77123	2177287

SOURCE: Alaska Oil and Gas Conservation Commission, Statistical Reports, 1977-82; State of Alaska Department of Natural Resources, Division of Oil and Gas, Annual Reports, 1968-76; and State of Alaska Department of Natural Resources, Division of Mines and Minerals, Annual Reports, 1959-67.

Data collected by the Alaska Oil and Gas Conservation Commission on drilling activity by geographical location allows the identification of drilling activity in the Cook Inlet Basin, on the North Slope, and in other areas of the state. The drilling associated with these three regions (Cook Inlet, North Slope, and other areas of Alaska) was estimated as a fraction of total drilling activity in order to derive regional estimates of drilling footage, as shown in Table B.13. The sources used to derive these estimates of footage by region made no distinction between drilling on land or offshore although it is clear that much of the drilling in the Cook Inlet area has been from offshore platforms while drilling on the North Slope has been largely onshore.

Drilling cost data was found from several sources. The most authoritative source of data on historical drilling costs is the Joint Association Survey (JAS) of the oil- and gas-producing industry which has been issued annually since 1955, with the exception of the years 1957-1958. The JAS surveys contain the most detailed and systematically collected data available on drilling and well equipment costs.

The JAS survey defines costs to include both tangible and intangible costs. Reported expenditures reflect the costs for drilling dry holes as well as productive ones and equipping new productive wells through the Christmas tree installation. Included are costs of labor, materials, supplies, water, fuels, power, and direct overhead (i.e., field, district, and regional) for such operations as site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling hole, running and cementing casing, hauling materials, machinery and tool charges and rentals, with deductions for the value of materials to be salvaged after use where appropriate. For offshore wells, costs include expenditures for fixed platforms and islands. Not included in the costs reported by the JAS survey are expenditures related to

TABLE B.13.
ESTIMATED DRILLING ACTIVITY^a
BY REGION
(thousands of feet)

Year	Cook Inlet		North Slope		Other		Alaska Total	
	Footage	Percent	Footage	Percent	Footage	Percent	Footage	Percent
1959	120.0	87	0	0	17.9	13	137.9	100
1960	210.8	81	0	0	49.5	19	260.3	100
1961	450.4	90	0	0	50.1	10	500.5	100
1962	307.8	82	0	0	67.6	18	375.4	100
1963	194.3	90	4.3	2	17.2	8	215.6	100
1964	147.2	82	25.1	14	7.2	4	179.5	100
1965	255.0	95	10.7	4	2.7	1	268.4	100
1966	522.9	95	21.8	5	1.8	*	546.5	100
1967	887.9	98	18.1	2	0	0	906.1	100
1968	1137.2	97	35.2	3	0	0	1172.4	100
1969	709.7	58	465.0	38	48.9	4	1223.6	100
1970	201.3	28	452.9	63	64.7	9	779.0	100
1971	53.5	16	281.1	84	0	0	334.6	100
1972	142.7	48	139.7	47	14.8	5	297.3	100
1973	176.3	63	95.1	34	8.4	3	279.8	100
1974	175.2	49	171.6	48	10.7	3	357.5	100
1975	250.3	37	412.7	61	13.5	2	676.6	100
1976	288.2	36	496.4	62	8	1	800.7	100
1977	204.3	30	449.5	66	27.2	1	681.0	100
1978	215.6	25	646.3	75	0	0	862.2	100
1979	171.0	17	852.9	83	0.4	*	1023.9	100
1980	81.2	6	1259.1	93	13.5	1	1353.9	100
1981	130.7	7	1718.0	92	18.7	1	1867.4	100
1982	174.2	8	2003.1	92	0	0	2177.3	100

*Less than one half of one percent.

^aTotal footage drilled annually from the Alaska Oil and Gas Conservation Commission. Estimates of regional footage drilled annually estimated from data published by the Alaska Oil and Gas Conservation Commission (Annual Statistical Reports 1977-1982); State of Alaska Department of Natural Resources, Division of Oil and Gas (Annual Reports 1968-1976); and State of Alaska Department of Natural Resources, Division of Mines and Minerals (Annual Reports 1959-1967). Figures shown reflect exploratory, development and service well footage on land and offshore.

production. These include lease equipment such as artificial lift and downhole lift equipment, flow lines, flow tanks, and separators.

Data from the JAS survey, 1953-1981, for the United States as a whole is summarized in Table B.14. Including the costs of drilling dry holes, U.S. average onshore costs have increased from about \$12.00 per foot in 1959 to over \$80 per foot in 1981. Offshore drilling costs were about \$38 per foot in 1959 and rose to almost \$385 per foot in 1981. Data for Alaska from the JAS survey is also shown in Table B.14 for the years 1975-1981. As shown in Table B.15, average onshore drilling costs per foot in Alaska were five-to-ten times higher than the U.S. average drilling costs per foot during the period 1975 to 1981. Offshore drilling costs in Alaska during the period 1975-1981 have also generally been higher, although not to the same degree as onshore costs. In fact, during two years, 1978 and 1980, Alaska offshore drilling costs were only 60-90 percent of the U.S. average. This may reflect the fact that offshore drilling in Alaska during this period was largely development drilling in the Cook Inlet area from existing platforms, whereas offshore drilling in other parts of the country was taking place in frontier OCS areas.

Another estimate of Alaska drilling costs is available from the Council on Energy Resources (CER) at the University of Texas at Austin. The CER data is presented as constant dollar (1976 \$) estimates of drilling costs per foot for cost regions compatible with U.S. Census regions. Alaska and Hawaii costs are presented together, although the limited oil and gas activity in Hawaii results in these figures being essentially Alaska costs, as shown in Table B.16.

A study by Erickson and Latham (1976) for the Legislative Affairs Agency provided cost estimates for drilling and development in the Cook Inlet Basin 1957-1975 as shown in Table B.17. The study distinguished between the cost of exploratory (wild cat) drilling

TABLE B.14.
DRILLING COSTS
(dollars per foot)

Year	U.S. Average Costs ^a			Alaska Costs ^b		
	Onshore	Offshore	All Types	Onshore	Offshore	All Types
1953	12	31	12	*	*	*
1954	*	*	*	*	*	*
1955	11	40	12	*	*	*
1956	12	43	12	*	*	*
1957	*	*	*	*	*	*
1958	*	*	*	*	*	*
1959	12	38	13	*	*	*
1960	12	37	13	*	*	*
1961	12	38	13	*	*	*
1962	12	35	13	*	*	*
1963	12	36	13	*	*	*
1964	12	35	13	*	*	*
1965	13	39	13	*	*	*
1966	13	45	15	*	*	*
1967	13	48	16	*	*	*
1968	13	53	17	*	*	*
1969	14	57	18	*	*	*
1970	16	58	19	*	*	*
1971	16	58	19	*	*	*
1972	17	63	21	*	*	*
1973	19	69	23	*	*	*
1974	26	92	29	*	*	*
1975	32	120	37	274	181	257
1976	34	150	40	292	176	273
1977	39	178	47	380	204	342
1978	48	219	57	423	194	395
1979	57	259	68	347	316	346
1980	67	308	77	371	199	369
1981	83	385	94	420	0	420

*Not available.

^aU.S. average costs from Basic Petroleum Data Book, Vol. III, No. 3 (September 1983) which reported data from the "Joint Association Survey of the U.S. Oil and Gas Producing Industry" annual survey on drilling costs. Values rounded to nearest whole dollar.

^bAlaska cost data from Joint Association Survey annual reports 1975-1981.

TABLE B.15.
INDEX OF JAS ALASKA DRILLING COSTS
RELATIVE TO JAS U.S. AVERAGE COSTS

<u>Year</u>	<u>Onshore</u>	<u>Offshore</u>
1975	8.6	1.5
1976	8.6	1.2
1977	9.7	1.1
1978	8.8	0.9
1979	6.1	1.2
1980	5.5	0.6
1981	5.1	NA

NA - Not applicable; no Alaska offshore drilling reported in JAS survey for 1981.

SOURCE: Table 14.

TABLE B.16.
DRILLING COSTS BY COST REGION^a
(dollars per foot)

Year	1976 Dollars		Current Dollars ^b	
	Alaska-Hawaii	Ak-Offshore	Alaska-Hawaii	Ak-Offshore
1969	406	337	266	221
1970	268	314	185	217
1971	218	285	158	206
1972	311	233	235	176
1973	211	166	169	133
1974	307	159	267	138
1975	*	*	*	*
1976	*	*	*	*
1977	340	159	360	168
1978	352	159	400	181
1979	364	159	450	196
1980	376	159	507	214
1981	389	159	574	234
1982	403	159	630	249
1983	416	159	*	*
1984	431	159	*	*
1985	446	159	*	*

*Not available.

^aData for 1977-1985 based on CER projections from historic costs assuming real cost growth rates of 0.0344 percent (Alaska-Hawaii) and 0.0 percent (Alaska Offshore). Cost regions adapted from U.S. Census regions. All figures rounded to nearest whole dollar.

^bCurrent dollar values derived using GNP deflator.

SOURCE: Council on Energy Resources, National Energy Policy: A Continuing Assessment, University of Texas at Austin (1978).

TABLE B.17.
ESTIMATED DRILLING AND DEVELOPMENT COSTS
IN THE COOK INLET BASIN 1957-1975
(thousands of dollars)

<u>Year</u>	<u>Exploration Drilling</u>	<u>Development Drilling</u>	<u>Platform Investments</u>	<u>Total</u>
1957	1794	0	0	1794
1958	2010	0	0	2010
1959	810	355	0	1165
1960	3149	9780	0	12929
1961	11057	18496	0	29553
1962	14848	4993	0	19841
1963	8232	4635	0	12867
1964	14273	696	0	14969
1965	18618	5261	25590	49469
1966	14993	17600	10491	43084
1967	41325	37200	6012	84537
1968	23080	110264	1966	13531
1969	14454	78642	3446	96542
1970	6924	22749	0	29673
1971	5533	4049	0	9582
1972	7888	17558	0	25446
1973	15360	20666	0	36026
1974	8432	26949	0	35381
1975	14176	36280	0	50456

SOURCE: Erickson and Latham (1976).

and development drilling with the latter estimated to be approximately two-thirds as expensive per foot drilled as shown in Table B.18. The study by Erickson and Latham indicates that exploratory drilling costs rose from about \$75/foot in the late 1950s to approximately \$300/foot in 1975. Development drilling costs during the same period rose from about \$56/foot to about \$200/foot. The study by Erickson and Latham identified the costs for Cook Inlet platforms from drilling costs. (The study by Erickson and Latham drew heavily on the DOR study cited previously.)

As noted previously, drilling costs described by the JAS survey account only for expenditures for drilling dry holes and productive wells and equipping new productive wells through the Christmas tree installation. A precise definition of drilling costs is not provided in the CER report, nor is a precise definition of drilling costs included in the study by Erickson and Latham.

Mead (1980) notes the need to account for costs of equipment "beyond the Christmas tree" or those necessary to convert a drilled well into a producing well. The U.S. Department of Commerce, Bureau of the Census, publishes an annual survey of the oil and gas industry nationwide, which includes an accounting of expenditures for "lease equipment" defined as "expenditures beyond the Christmas tree installation, including flow lines, flow tanks, field separators, heater-treaters, production platforms, and related field facilities (including) artificial lift equipment . . . required for primary production." Data from the Department of Commerce survey indicates that, between 1973-1981, expenditures for lease equipment has averaged about 20 percent of total expenditures for drilling and equipping wells, as shown in Table B.19.

A historical accounting Alaska drilling and development costs is also available from the Legislative Finance Division Producer Benefits Model (PBM). The PBM has fiscal year capital cost data for each of three historically producing areas in the state--Cook Inlet,

TABLE B.18.
DRILLING AND DEVELOPMENT COSTS
COOK INLET BASIN 1957-1975^a
(dollars per foot)

<u>Calendar Year</u>	<u>Exploratory Drilling (\$/ft)</u>	<u>Development Drilling (\$/ft)</u>
1957	71	NA
1958	81	NA
1959	85	56
1960	88	59
1961	92	61
1962	95	64
1963	99	58
1964	103	93
1965	107	65
1966	126	108
1967	146	63
1968	165	110
1969	184	123
1970	204	136
1971	223	149
1972	242	161
1973	261	174
1974	281	187
1975	300	200

NA - Not applicable; no development drilling.

^aCost figures rounded to nearest whole dollar.

SOURCE: Erickson and Latham (1976).

TABLE B.19.
U.S. EXPENDITURES FOR LEASE EQUIPMENT
AS PERCENTAGE OF TOTAL DRILLING COSTS
(millions of dollars)

<u>Year</u>	<u>Lease Equipment^a</u>	<u>Drilling Wells^b</u>	<u>Percent^c</u>
1973	572.2	2711.0	21.1
1974	824.1	3845.7	21.4
1975	1499.6	5478.8	27.3
1976	1486.8	6621.5	22.4
1977	1607.9	8933.7	18.0
1978	2175.0	10937.0	19.9
1979	2146.0	13191.7	15.8
1980	3572.8	18872.0	18.9
1981	\$4760.3	\$29653.2	16.1%

^aDefined as equipment beyond the Christmas tree installation required for primary production. See text.

^bIncludes of both exploratory and development well drilling.

^cLease equipment expenditures as a percent of costs for drilling wells. Nine-year average equals 20.1 percent.

SOURCE: U.S. Department of Commerce, Bureau of Census: Annual Survey of Oil and Gas as published in the Basic Petroleum Data Book Vol. III, No. 3 (September 1983).

Sadlerochit, and Kuparuk--as well as capital costs for two areas expected to produce in the future--Beaufort Sea and east of Prudhoe. While neither of the latter two areas has yet gone into production, the PBM allocates a portion of historic North Slope capital costs to these two areas, as shown in Table B.20.

Capital costs reported in the PBM for Cook Inlet date from fiscal year 1958 with an expenditure of \$8 million. This value steadily increases to a nominal dollar peak value of \$122 million in fiscal year 1968 and then drops to about \$50 million per year throughout most of the 1970s.

Capital costs in the PBM for the North Slope climb rapidly from \$5 million in 1965 for the Sadlerochit field to nearly \$500 million in 1970 (this includes \$96 million for Kuparuk and \$7 million for other North Slope developments). North Slope development costs for the Sadlerochit field rose to over \$1 billion annually for the period 1976-1977, reflecting major initial expenditures for field development (gathering lines, personnel facilities, etc.), along with substantial development drilling. Between 1978-1980, expenditures for the Sadlerochit field dropped to an annual average of about \$580 million, followed by another surge in costs during the early 1980s for the waterflood project, which cost about \$1.75 billion annually during 1981-1982. During this same period, costs for Kuparuk and other arctic areas increased total North Slope capital costs several hundred million, as shown in Table B.20. The PBM capital cost values do not reflect expenditures for the TAPS line.

Finally, another measure of drilling and development costs is available from the National Petroleum Council (NPC) which estimated arctic drilling and development costs as part of a comprehensive review of Alaska's oil and gas potential. According to the NPC study, a rough "rule of thumb" is that there is a minimum cost of \$10 million (in 1981 dollars) for a ten-thousand-foot well on the

TABLE B.20.
OIL AND GAS FIELD CAPITAL COSTS^a
(millions of dollars)

<u>Fiscal Year</u>	<u>Cook Inlet</u>	<u>Sadlerochit</u>	<u>Kuparuk</u>	<u>Other NS^b</u>
1958	8	0	0	0
1959	17	0	0	0
1960	32	0	0	0
1961	46	0	0	0
1962	51	0	0	0
1963	37	0	0	0
1964	31	0	0	0
1965	53	5	0	0
1966	67	3	0	0
1967	81	1	0	0
1968	122	6	0	6
1969	120	48	0	7
1970	66	374	96	7
1971	22	117	6	0
1972	21	75	6	0
1973	36	53	6	6
1974	41	167	6	0
1975	46	603	6	13
1976	55	1158	6	13
1977	56	1010	6	21
1978	59	590	6	7
1979	63	535	15	19
1980	47	628	101	13
1981	50	1532	227	46
1982	41	1980	534	44

^aFiscal year capital costs estimates for oil and gas field development. The figures shown do not reflect costs associated with the Trans-Alaska Pipeline system.

^bOther North Slope oil and gas field development costs includes expenditures allocated by the PBM to development of the Beaufort Sea and areas east of Prudhoe Bay.

SOURCE: Legislative Finance Division, Producer Benefits Model (1982).

North Slope. Between well depths of ten and fifteen thousand feet, one million dollars should be added for every one-thousand-foot increment. Two million dollars should be added for each one-thousand-foot increment beyond fifteen thousand feet. An additional two to five million dollars should then be factored in the approximate total well costs. Cost estimates for a twelve-thousand-foot exploration well on the North Slope and in frontier OCS areas are summarized in Table B.21.

The costs associated with developing commercially attractive finds in arctic areas was also examined by the NPC study. General cost estimates (in 1981 dollars) were developed as shown in Table B.22. For onshore areas on the North Slope, the NPC study estimated that development wells for a one- to two-billion-barrel field would cost \$3.5-4.5 million each. An additional investment of \$2.6-4.5 billion in support facilities suggests a total capital cost of about \$20-24 million per development well on the North Slope. As shown by Table B.22, development costs in frontier OCS areas are generally much higher than in other regions.

4.0 Operation Costs

Estimates of operating costs associated with oil and gas development vary widely depending upon the nature of the field operations. The "National Stripper Well Survey: 1944-1979" indicates that annual operating costs for an onshore stripper well are approximately \$9,000, as reported by Gruy (1981). In contrast to this, Mead (1980) estimates the annual cost of operating a productive offshore well in the Gulf of Mexico to be \$90,000 for 1976, as shown in Table B.23.

Estimated operating costs for Alaska's producing oil and gas regions are available from the Alaska Legislative Finance Division Producer Benefits Model (PBM), which has historical data for operating costs by major producing areas of the state--Cook Inlet, Sadlerochit, and Kuparuk. Estimates of future production costs are

TABLE B.21.
EXPLORATION WELL COSTS
FOR A WELL 12,000 FEET DEEP
(millions of 1981 dollars)

<u>Area</u>	<u>Roads, Island Pad, Etc.</u>	<u>Drilling Cost</u>	<u>Total Well Cost</u>
ANWR	17	11	28.0
North Slope	15	10	25.0
Other/NPRA			
Bristol	-	32	32.0
St. George	-	32.	32.0
Norton	-	24	24.0
Navarin	-	46	46.0
Chukchi	-	90	90.0
Beaufort	50/Island 20/Well ^a	20	40.0

^aAssumes 2.5 wells per island.

SOURCE: National Petroleum Council (1981); Appendix E.

TABLE B.22.
ESTIMATED FIELD DEVELOPMENT COSTS
(millions of 1981 dollars)

	<u>ANWR</u>	<u>North Slope Other/NPRA</u>	<u>Bristol Bay</u>	<u>St. George</u>	<u>Norton</u>	<u>Navarin</u>	<u>Chukcki</u>	<u>Beaufort</u>
Field Size (BBO)	1	2	1	1	0.5	2	1	2
No. of Islands or Platforms Required	-	-	4	4	2	9	4	7
Total Cost of Islands or Platforms (MM \$)	-	-	480	1,600	420	4,300	1,520	1,330
Total No. of Wells ^a	136	271	128	136	68	271	136	271
Cost Per Dev. Well (MM \$)	4.5	3.5	7.8	8.9	10.2	8.8	7.2	6.8
Total Cost of Dev. Wells (MM \$)	610	950	1,000	1,210	690	2,400	980	1,840
Cost of Facilities (MM \$)	2,600	4,500	1,200	1,200	620	2,400	1,200	2,100
Total Capital (MM \$)	3,210	5,450	2,680	4,010	1,730	9,100	3,700	5,270

^aIncludes 0.4 water injectors per producer plus gas injectors.

SOURCE: National Petroleum Council (1981); Appendix E.

TABLE B.23.
ANNUAL OPERATING COSTS: GULF OF MEXICO^a
(dollars per well)

Year	Cost
1954	\$35,000
1955	35,000
1956	35,000
1957	35,000
1958	35,000
1959	35,000
1960	35,000
1961	35,000
1962	35,000
1963	35,000
1964	38,000
1965	38,000
1966	38,000
1967	40,000
1968	40,000
1969	41,000
1970	42,000
1971	42,000
1972	54,000
1973	60,000
1974	70,000
1975	90,000
1976	90,000

^aOperating costs per well were estimated from data collected by the Joint Association Survey (JAS) and from a special survey conducted by Mead. Included were lifting costs and all other costs directly applicable to the production of petroleum as distinguished from drilling and initial installment of equipment necessary for production. No distinction made between oil and gas wells.

SOURCE: Mead (1980).

also forecast in the PBM for two areas of anticipated production--the Beaufort and the area east of Prudhoe Bay.

For the Cook Inlet area, the PBM has annual estimates of operation costs back to fiscal year 1958 in millions of dollars. The values found in the PBM indicate that Cook Inlet total operating costs grew from about \$1 million in 1961 to \$90 million in 1982. Together with data from the Alaska Oil and Gas Conservation Commission (Table B.24) regarding the number of active wells in the Cook Inlet region, the PBM cost values suggest operations cost of about \$20,000-30,000 per active well in the early 1960s rising to \$250,000 per well by the early 1980s, as shown in Table B.25. (The definition of "active wells" in this analysis is producing wells plus reinjection wells exclusive of shut-ins.)

Operational cost data for the North Slope from the PBM primarily reflects costs associated with the Sadlerochit field with a very small portion of (fiscal year) 1982 costs attributable to Kuparuk field operations. The PBM figures suggest that, at about \$1 million per well, annual operating costs are far greater for the North Slope than for Cook Inlet. The PBM data also indicate a decline in operating costs per well over the period 1978 to 1982, reflecting large annual increases of the number of production wells developed during this period.

An alternative estimate of annual variable operating costs for the Cook Inlet region for the period 1959-1975 is available from the study by Erickson and Latham (1976). Variable operating costs shown in Table B.26 are based on an estimated cost of \$0.25/barrel and \$0.01/mcf dry gas in 1975.

The National Petroleum Council (NPC) (1981) also considered production-related operations costs as part of its study of arctic oil and gas resources. The NPC study estimated annual operating expenses associated with production of oil in different regions of

TABLE B.24.
NUMBER OF ACTIVE WELLS BY TYPE, 1959-1982^a

Fiscal Year	Cook Inlet				North Slope			
	Oil	Gas	Inject	Total	Oil	Gas	Inject	Total
1959	5	0	0	5	0	1	0	0
1960	12	1	0	13	0	1	0	0
1961	45	3	0	48	0	1	0	0
1962	47	7	2	56	0	1	0	0
1963	54	9	3	66	0	1	0	0
1964	54	8	1	63	0	2	0	0
1965	53	11	3	67	0	2	0	0
1966	66	18	7	91	0	2	0	0
1967	94	20	8	122	0	2	0	0
1968	174	29	12	215	0	3	0	0
1969	192	41	43	276	1	0	1	2
1970	202	46	56	304	2	0	0	2
1971 ^b	200	45	65	310	2	0	0	2
1972	193	45	74	312	2	0	1	3
1973	191	46	73	310	2	0	0	2
1974	197	46	73	316	2	0	2	4
1975 ^b	200	52	75	327	3	0	2	5
1976	203	57	77	337	4	0	2	6
1977	213	58	70	341	105	0	12	117
1978	217	62	73	352	152	0	17	169
1979	220	67	71	358	197	0	18	215
1980	226	65	63	354	238	0	28	266
1981	231	73	71	375	293	0	29	322
1982	227	91	74	392	403	0	36	439

^aActive wells defined to include flowing wells plus producing wells using artificial pumps or lift together with operative injection wells. Well count as of December in the year indicated. Exclusive of South Barrow field.

^bEstimated.

SOURCE: Alaska Oil and Gas Conservation Commission Well Counts (unpublished data).

TABLE B.25.
ESTIMATED HISTORICAL OPERATING COSTS IN ALASKA
BY MAJOR PRODUCING AREA^a
(thousands of dollars)

Fiscal Year	Cook Inlet			North Slope ^b		
	Cost	No. Wells	\$/Well	Cost	No. Wells	\$/Well
1958	0	NA	-	0	0	0
1959	0	NA	-	0	0	0
1960	0	5	*	0	0	0
1961	1,000	13	76.9	0	0	0
1962	1,000	48	20.8	0	0	0
1963	2,000	56	35.7	0	0	0
1964	2,000	66	30.3	0	0	0
1965	2,000	63	31.7	0	0	0
1966	2,000	67	29.9	0	0	0
1967	4,000	91	44.0	0	0	0
1968	9,000	122	73.8	0	0	0
1969	15,000	215	69.8	0	0	0
1970	17,000	276	61.6	0	2	*
1971	18,000	304	59.2	0	2	*
1972	18,000	310	58.1	0	2	*
1973	18,000	312	57.7	0	3	*
1974	18,000	310	58.1	0	2	*
1975	18,000	316	57.0	0	4	*
1976	24,000	327	73.4	0	5	*
1977	31,000	337	92.0	0	5	*
1978	40,000	341	117.3	161,000	117	1,367.5
1979	69,000	352	196.0	204,000	169	1,207.1
1980	89,000	358	248.6	237,000	215	1,102.3
1981	90,000	354	254.2	243,000	266	913.5
1982	90,000	375	240.0	251,000	322	779.5

NA - Not Available.

*Operating cost values in PBM given as 0 (less than one million).

^aNumber of wells shown include flowing wells plus producing wells using artificial lift or pumps together with operating injection wells. Well count as of December in the middle of the fiscal year shown (Table B.24).

^bExclusive of South Barrow field.

SOURCE: Legislative Finance Division Producer Benefit Model (1982);

Alaska Oil and Gas Conservation Commission Well Counts (unpublished data).

TABLE B.26.
ESTIMATED COOK INLET OIL AND GAS
OPERATING COSTS, 1959-1975^a
(thousands of dollars)

Year	Variable Oil Operating Costs ^b	Variable Gas Operating Costs ^c
1958	5	0
1959	28	0
1960	90	2
1961	1,045	4
1962	1,746	18
1963	1,883	82
1964	1,996	89
1965	2,070	87
1966	2,752	348
1967	5,706	405
1968	13,446	491
1969	15,559	766
1970	18,031	1,311
1971	17,499	1,259
1972	16,829	1,269
1973	17,235	1,247
1974	17,534	1,260
1975	17,702	1,274

^aProduction data used in this calculation is from Division of Oil and Gas Statistical Reports, except 1975 which was estimated by the Division of Research Services.

^bOperating costs at \$.25 per bbl. in 1975; prior years based on 3 percent annual inflation rate, i.e.,

$$\text{Variable operating costs in Year } t = \frac{\$.25}{1.03^{1976-t}}$$

^cOperating costs at \$.01 mcf dry gas production.

SOURCE: Erickson and Latham (1976).

Alaska by making assumptions about the size of field discoveries, the number of development wells, and peak production rates, as shown in Table B.27. The cost estimates presented in the NPC study indicate that annual operating costs (1981 dollars) on the North Slope are about \$520,000-590,000 per well, with offshore costs generally far higher. The highest operating costs per well are projected for the Norton Basin at approximately \$1,250,000 per well, although this is perhaps attributable to the relatively small field size (0.5 BBO) assumed.

TABLE B.27.
NPC OIL PRODUCTION COST ESTIMATES
(millions of 1981 dollars)

	ANWR	North Slope Other/NPRA	Bristol Bay	St. George	Norton	Navarin	Chukchi	Beaufort
Field Size (BBO)	1	2	1	1	0.5	2	1	2
Field Peak Production Rate (B/D)	250,000	500,000	250,000	250,000	125,000	500,000	250,000	500,000
Total No. of Wells ^a	136	271	128	136	68	271	136	271
Operating Expenses (MM \$/Yr)	80	140	110	110	85	200	140	140
Operations Cost per Well (MM \$/Yr)	0.59	0.52	0.86	0.81	1.25	0.74	1.03	0.52

^aIncludes 0.4 water injectors per producer plus gas injectors.

SOURCE: National Petroleum Council (1981), Appendix E.

ENDNOTE

¹The Division of Mines and Minerals was subsequently abolished and its petroleum industry functions were transferred to the DNR Division of Oil and Gas. The Division of Oil and Gas was, in turn, disbanded and replaced by the Division of Minerals and Energy Management.

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APPENDIX C

TIMING OF EXPLORATION, LEASING, AND DEVELOPMENT

1.0 Introduction

In Alaska's frontier areas, where hundreds of millions of dollars in lease bonus bids may be involved, the costs associated with schedule delays between leasing and production will have significant bearing on the overall economics of a given development effort. In addition to the initial costs of lease acquisition, the value of other expenditures for exploratory investigations, drilling, and production facilities must be considered within the context of the timing of field development, the size of a given discovery and its productive life. Recent discussions with oil company executives suggest that preventing delays in the development of Alaska's frontier petroleum regions could provide savings well in excess of \$100 million per year.

2.0 Historically Producing Areas

We examined the histories of currently producing oil and gas fields in Alaska to determine the length of time between exploration, leasing, discoveries, and production. The two major producing regions of the state, Cook Inlet and the North Slope, were evaluated to determine the historical patterns of timing for exploration and development activities. The results of this review are summarized in Table C.1.

Cook Inlet

The histories of ten actively producing oil and gas fields in Cook Inlet region are depicted graphically in Figure C.1. The individual field histories are documented in Table C.2. Data is not available regarding geological and geophysical exploration activities associated with individual fields. Some cost data on exploration in the Cook Inlet basin as a whole is available from the American Association of Petroleum Geologists and the Society of

TABLE C.1.
HISTORIC TIMING OF LEASING,
DISCOVERY AND PRODUCTION
IN ALASKA^a

<u>REGION/FIELD</u>	<u>SALE-DISCOVERY^b</u>	<u>DISCOVERY-PRODUCTION^c</u>
<u>Cook Inlet</u>		
o Beluga River	7.5 yrs.	4 yrs.
o Beaver Creek	18 yrs.	1 yr.
o Granite Point	3.5 yrs.	2 yrs.
o Kenai	5 yrs.	2 yrs.
o McArthur River	4 yrs.	2 yrs.
o Middle Ground Shoals	0.5 yrs.	2.5 yrs.
o Nicolai Creek	9 yrs.	2.5 yrs.
o North Cook Inlet	1 yr.	6.5 yrs.
o Swanson River	3 yrs.	3 yrs.
o Trading Bay	3.5 yrs.	1.5 yrs.
<u>North Slope</u>		
o Prudhoe Bay	3 yrs.	9.5 yrs.
o Kuparuk	3.5 yrs.	13.5 yrs.

^aSummary of the time periods between the initial leasing of selected oil and gas fields which were subsequently discovered and developed into production. Dates rounded to nearest half year.

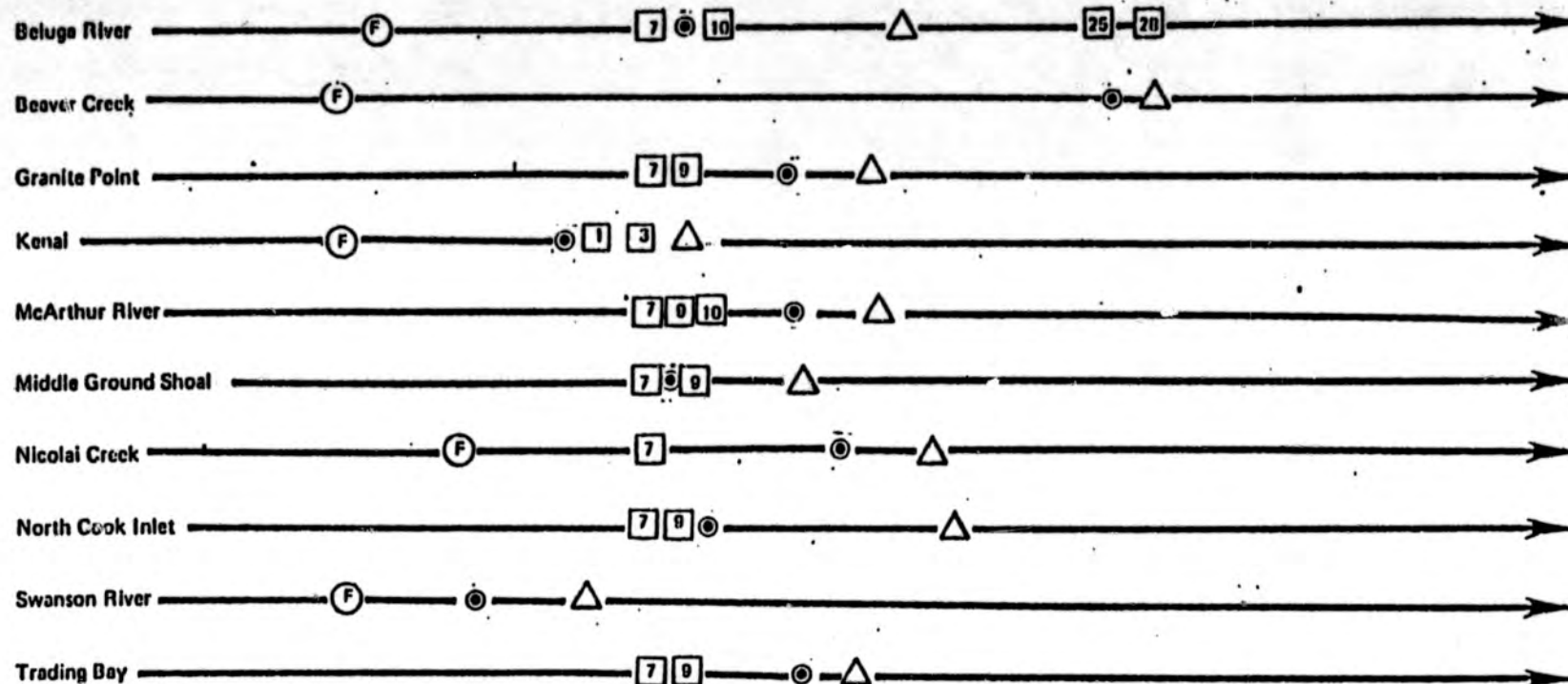
^bTime between initial lease acquisition by either noncompetitive federal over-the-counter lease application or competitive state bonus bid sale.

^cTime between field discovery and first production.

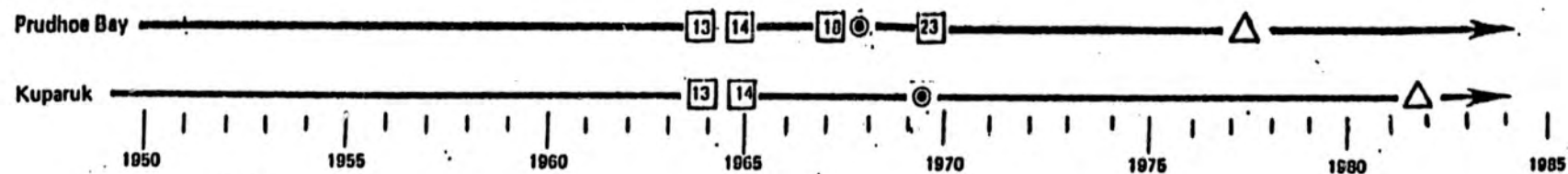
SOURCE: see text.

Figure C.1 Timing of Leasing, Discovery, and Production of Alaska Oil and Gas Fields

COOK INLET



NORTH SLOPE



KEY

- (F) Federal Noncompetitive Lease
- [n] State Competitive Lease Sale number
- Discovery
- △ Production

TABLE C.2.
COOK INLET OIL AND GAS FIELD
LEASING, DISCOVERY AND PRODUCTION HISTORIES

<u>AREA/FIELD</u>	<u>ACTIVE LEASES^a</u>	<u>LEASE DATE^b</u>	<u>DISCOVERY^c</u>	<u>PRODUCTION^c</u>
COOK INLET				
Beluga River	Federal: AD-29656 AD-29657 State: ADL 17592 ADL 17599 ADL 21126 ADL 21127 ADL 21128 ADL 21129 ADL 17658 ADL 58815 (S) ADL 58820 (S) ADL 58831 (S) ADL 63055	OTC-4/55 OTC-4/55 No. 7-12/61 No. 7-12/61 No. 10-5/63 No. 10-5/63 No. 10-5/63 No. 10-5/63 OTC-12/56 No. 25-9/72 No. 25-9/72 No. 25-9/72 No. 28-12/73	12/62	1/68
Beaver Creek	Federal: AO 28078 AO 28118 AO 28120	OTC-10/54 OTC-10/54 OTC-10/54	1/73	12/73
Granite Point	State: ADL 17586 ADL 17587 ADL 17597 ADL 18742 ADL 18761 ADL 18776 ADL 35431 (S)	No. 7-12/61 No. 7-12/61 No. 7-12/61 No. 9-7/62 No. 9-7/62 No. 9-7/62 No. 9-7/62	6/65	3/67
Kenai	Federal: AO 28047 AO 28055 AO 28056 AO 28103 AO 28140 AO 28142 AO 28143 State: ADL 00588 ADL 00593 ADL 00594 ADL 02411 ADL 02497 ADL 308223 (S) ADL 324598 (S)	OTC-10/54 OTC-10/54 OTC-10/54 OTC-10/54 OTC-10/54 OTC-10/54 OTC-10/54 No. 1-12/59 No. 1-12/59 No. 1-12/59 No. 3-12/60 OTC-10/58 OTC-10/54 OTC-10/54	10/59	1/62

Table C.2 (continued)

<u>AREA/FIELD</u>	<u>ACTIVE LEASES^a</u>	<u>LEASE DATE^b</u>	<u>DISCOVERY^c</u>	<u>PRODUCTION^c</u>
McArthur River	State:		10/65	10/67
	ADL 17579	No. 7-12/61		
	ADL 17594	No. 7-12/61		
	ADL 17602	No. 7-12/61		
	ADL 18716	No. 9-7/62		
	ADL 18729	No. 9-7/62		
	ADL 18730	No. 9-7/62		
	ADL 18758	No. 9-7/62		
	ADL 18772	No. 9-7/62		
	ADL 18777	No. 9-7/62		
	ADL 21068	No. 10-5/63		
Middle Ground Shoals	State:		6/62	11/65
	ADL 17595	No. 7-12/61		
	ADL 18744	No. 9-7/62		
	ADL 18746	No. 9-7/62		
	ADL 18754	No. 9-7/62		
	ADL 18756	No. 9-7/62		
Nicolai Creek	Federal:		5/66	10/68
	AA 08426	OTC-10/58		
	State:			
	ADL 17585	No. 7-12/61		
	ADL 17598	No. 7-12/61		
	ADL 63279	OTC-4/57		
North Cook Inlet	State:		8/62	5/69
	ADL 17589	No. 7-12/61		
	ADL 17590	No. 7-12/61		
	ADL 18740	No. 9-7/62		
	ADL 18741	No. 9-7/62		
	ADL 37831 (S)	No. 9-7/62		
Swanson River	Federal:		8/57	6/60
	AO 28077	OTC-10/54		
	AO 28384	OTC-11/54		
	AO 28405	OTC-11/54		
	AO 28396	OTC-11/54		
	AO 28399	OTC-11/54		
	AO 28990	OTC-1/55		
	AO 28993	OTC-1/55		
	AO 28996	OTC-1/55		
	AO 28997	OTC-1/55		

Table C.2 (continued)

<u>AREA/FIELD</u>	<u>ACTIVE LEASES^a</u>	<u>LEASE DATE^b</u>	<u>DISCOVERY^c</u>	<u>PRODUCTION^c</u>
Trading Bay	State: ADL 17597 ADL 18731 ADL 18776 ADL 35431	No. 7-12/61 No. 9-7/62 No. 9-7/62 No. 9-7/62	6/65	1/67

North Slope

- Prudhoe Bay
The actively producing leases associated with the Prudhoe Bay field were all acquired in four separate competitive state lease sales No. 13 (12/64), No. 14 (7/65), No. 18 (1/67) and No. 23 (9/69). Discovery of the field was made in January 1968 with commercial production in June 1977.
- Kuparuk
The actively producing leases associated with the Kuparuk field were all acquired in competitive state lease sales No. 13 (12/64) and No. 14 (7/65). Discovery of the field was made in April 1969 with commercial production following in December 1982.

OTC - Federally leased noncompetitive, over-the-counter lease.

S - Segregated lease.

^aActive federal leases identified from lease maps prepared by Alaska Map Service and confirmed at the Bureau of Land Management. Active state leases identified as published in "Historical and Projected Oil and Gas Consumption," January 1983, by the Alaska Department of Natural Resources Division of Minerals and Energy Management (Appendix A, Royalty Oil and Gas Data by Field). State leases with issue dates prior to 1959 were federally leased lands subsequently acquired by the state.

^bThe date reflected as "lease date" indicates when the oldest, currently productive lease in the field was first secured by either a federal noncompetitive OTC lease application or as part of a state competitive sale.

^cDate of discovery and first production from Alaska Oil and Gas Conservation Commission annual statistical reports. Where more than one pool in a field have been developed, the pool first developed was used to indicate first production.

SOURCE: see text.

Exploration Geophysicists. It is not possible, however, to relate this data to specific fields and discoveries.

Federal and state leases associated with each of the ten producing fields are also identified in Table C.2. Federal leases associated with producing fields were ascertained from leasing maps prepared by Alaska Map Service, available from the Department of Natural Resources. These maps show historically leased lands and identify individual leases. The lease histories for each federal lease were investigated at the Bureau of Land Management to determine when leasing investments were initially made. The dates under the column heading "lease date" in Table C.2 indicate when a given federal lease was secured through a noncompetitive, over-the-counter application. (The application date, rather than the date of issuance, is used because applicants initiated payments with the lease application.) Leasing costs for federal leases were typically \$10 in application fees plus about \$640 for the initial rental with additional rental fees paid subsequently. As shown by Table C.2, federal leases involving producing fields (including Beluga River, Beaver Creek, Kenai, Nicolai Creek, and Swanson River) were generally leased in the mid-1950s. The oldest actively producing lease for a particular field was used as the starting point of the individual field history. As shown in Figure C.1, about half of the fields in Cook Inlet were initially leased by noncompetitive, over-the-counter sales with the rest acquired through state competitive lease sales.

Actively producing state leases in the Cook Inlet basin were identified as part of a report on historic and projected oil and gas consumption by the Alaska Department of Natural Resources (1983). An appendix of the DNR report lists the state leases associated with each of the Cook Inlet fields. Additional information was obtained from the DNR Lease Enforcement Section. Each of these leases was then examined to determine when they had been initially acquired. Because some of the leases were transferred from the federal

government to the state, there are state leases shown in Table C.2 which were acquired by individuals or companies prior to statehood (e.g., Beluga River, Kenai, and Nicolai Creek).

Dates for individual field discoveries were obtained from the Alaska Oil and Gas Conservation Commission (AOGCC) Annual Statistical Reports. The date of first production was also determined from AOGCC field histories. Where multiple pools have been developed in a single field, the pool first developed was used to represent first production.

The Cook Inlet field histories depicted in Figure C.1 show a wide range of variation in the relationship between the timing of lease acquisition, development, and production. Of the ten fields considered, a simple average of the time between initial lease acquisition and discovery is 5.5 years. The shortest time between a lease sale and discovery is 0.5 years at Middle Ground Shoals and the longest was 18 years at Beaver Creek. The period between a discovery and first production was generally far less, averaging 2.7 years with a range of 6.5 years for the North Cook Inlet field to 1 year for Beaver Creek. In several instances, state competitive lease sales were held which involved acreage covering fields that had previously been discovered. Such "drainage" sales were held involving the Beluga River and Middle Ground Shoals fields in Cook Inlet.

North Slope

The histories of the two major producing fields on the North Slope, Prudhoe Bay and Kuparuk, were also examined for their historic relationship between leasing, discovery, and production. The DNR (1983) report cited above together with data from the DNR Lease Enforcement Section and the AOGCC Annual Reports were used to document the Prudhoe Bay and Kuparuk histories, as shown in Figure C.1 and Tables C.1 and C.2.

In the case of Prudhoe Bay, all of the currently producing leases were acquired in three competitive state lease sales with the earliest in July 1965. A discovery well followed approximately 2.5 years later. The record-breaking sale No. 23 was held shortly thereafter, bringing in over \$900 million in bonus bids for the drainage sale acreage. Commercial production was delayed until completion of the Trans-Alaska pipeline and started up 9.5 years following the discovery.

The currently producing leases of the Kuparuk field were all acquired in two competitive state lease sales in December 1964 and July 1965. The field was discovered in 1969, about 3.5 years following the first sale. First production, however, did not commence until 13.5 years following discovery.

3.0 Future Production

The National Petroleum Council (1981) examined the question of how the future timing of exploration and development activities could be expected to interrelate in frontier arctic onshore and offshore areas of Alaska. Basic scenarios were developed for each of the three major regions examined in the NPC study, as shown in Figure C.2. Region I involves North Slope onshore exploration and development activities while the other two regions involve offshore exploration and development. Region II is the Bering Sea, described as having "moderate" ice problems. Region III embraces the Beaufort Sea and Chukchi Sea and is described as having "severe" ice conditions. In each of the scenarios, the NPC study assumed that "the areas described are relatively unexplored, that large areas, completely covering entire structures, are readily available for lease and that the exploration process is unencumbered by governmental permits and regulation delays." Thus, each of the scenarios described in the NPC study is intended to represent the minimum time required to develop production, assuming a commercially attractive find is made. The timing of exploratory and development activities from the NPC study is summarized in Table C.3.



Figure C.2

Geographic Regions Used in National Petroleum Council Study

Note: The United States has not fully resolved its Continental Shelf boundaries with other states concerned. The lines on this map are for purposes of illustration only and do not necessarily reflect the positions or views of the United States with respect to the boundaries involved.

Source: National Petroleum Council (1981).

TABLE C.3.
TIMING OF EXPLORATION, LEASE SALES,
DISCOVERY AND PRODUCTION
SUMMARY OF NPC SCENARIOS^a

<u>REGION/AREA</u>	<u>EXPLORATION-SALE^b</u>	<u>SALE-DISCOVERY^c</u>	<u>DISCOVERY-PRODUCTION^d</u>
<u>Region I</u>			
North Slope Onshore	4.5 yrs.		
o AMR (250 MBpd)		2.5 yrs.	6.5 yrs.
o AMR (500 MBpd)		2.5 yrs.	6.5 yrs.
o Other (500 MBpd)		2.5 yrs.	6.5 yrs.
<u>Region II</u>			
Bering Sea	3.5 yrs.		
o Norton (125 MBpd)		3 yrs.	6 yrs.
o Navarin (500 MBpd)		3 yrs.	7 yrs.
o St. George (250 MBpd)		3 yrs.	6.5 yrs.
o Bristol Bay (250 MBpd)		3 yrs.	6.5 yrs.
<u>Region III</u>			
Beaufort-Chukchi Seas	3.5 yrs.		
o Beaufort Shelf (500 MBpd)		4 yrs.	7.5 yrs.
o Central Chukchi (250 MBpd)		6.5 yrs.	7.5 yrs.

MBpd - Thousands of barrels per day.

^aSummary of time requirements necessary for geophysical exploration activities, drilling and development to the point of first production assuming the discovery of commercially exploitable oil fields. Time requirements reflect the minimum time required under ideal business conditions.

^bTime required prior to lease sale for active geological and geophysical field exploration activities.

^cTime required after the lease sale for exploration drilling to locate significant field.

^dTime required after discovery to develop a given field to the point of first production.

SOURCE: National Petroleum Council (1981). Figures 6, 7, 8 and Appendix D.

The NPC study developed a total of fourteen basic scenarios for hydrocarbon development in the three geographic regions described by the study. Nine of the scenarios concerned possible oil developments with the balance addressing gas development. Because of the tenuous marketing prospects for arctic gas, we considered only the NPC scenarios regarding oil discovery and development.

For onshore areas on the North Slope (Region I), the timing reflected in the NPC study indicates that about 4-5 years are spent actively gathering site-specific geological and geophysical field data prior to the lease sale. Approximately 2-3 years of exploratory drilling following the sale is anticipated prior to a discovery and another 6-7 years required between the initial discovery and first production.

In the Bering Sea (Region II), assuming moderate ice conditions, about 3-4 years of detailed field exploration work is expected to precede the sale. About 3 years of exploratory drilling following the sale is required before a discovery is made, followed by another 6-7 years before first production. As shown in Table C.3, the NPC study indicates that field development could be most quickly achieved in Norton Sound after 6 years and would take somewhat longer in the Navarin Basin, about 7 years under ideal conditions.

In the Beaufort and Chukchi Seas (Region III), assuming severe ice conditions, about 3-4 years of exploration are anticipated prior to a sale. The time required for exploratory drilling prior to a discovery is about 4 years on the Beaufort Shelf but nearly 7 years in the Central Chukchi Sea. Following a discovery, about 7-8 years would be required to develop a find to the point of first production.

Thus, under favorable regulatory conditions, and depending on geographic location and size of discovery, the total time between pre-lease-sale exploration and ultimate production varies between 13.5 and 17.5 years.

REFERENCES FOR APPENDIX C

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Alaska Oil and Gas Conservation Commission, Annual Statistical Reports 1970-1982.

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

APPENDIX D

DOCUMENTATION OF MODEL HISTOIL

HISTOIL is a regional accounting model designed to replicate the structure of income, cost, taxes, lease terms, and economic rent for oil producing regions in Texas and Alaska. Appendix D consists of three parts: (1) variable documentation, (2) model listing of equations, and (3) a summary of data sources for exogenous cost variables.

The variable listing in Part 1.0 gives the name, definition, units, and in the case of the exogenous variables, the 1982 value for each of five study regions (Alaska Cook Inlet, Alaska North Slope, Other Alaska, Texas offshore, and Texas onshore). Variables are listed according to declaration type: exogenous, endogenous, definition, and parameter.

The model listing in Part 2.0 is divided into nine sections: revenue and cost, excise taxes, cash flow equations, cumulative cash flow before profit sharing and income taxes, capital recovery factors, prorated investment using capital recovery, cash flow assuming prorated investment, net profit sharing, and income taxes. This ordering does not reflect the block recursive structure of the model. Definition variables (identities) on the left-hand side of an equation can be distinguished from endogenous variables by the double equal sign.

Part 3.0 of Appendix D summarizes data sources for exogenous capital and operating cost variables for each of the five study regions. The entries in Table D.1 show the source, definition and range of selected data by study region for each cost variable in HISTOIL. All data sources in Table D.1 were not used; they were ranked according to accuracy and completeness. In general, sources at the top of the list were given preference over those lower down. Whereas Table D.1 is organized by study region, Table D.2 is organized by cost variable, showing characteristics of corresponding data sources, including: region covered, range, definition, and method of estimation.

1.0 Documentation of Model Histoil

Exogenous Variables

Variable	Definition	1982 VALUE				
		ALASKA			TEXAS	
		Cook Inlet	North Slope	Other	Off- shore	On- shore
<u>Production and Prices</u>						
POIL	Wellhead price of oil in dollars per bbl	27.79	19.69	0	32.35	31.62
PGAS	Wellhead price of natural gas in dollars per mcf	.591	1.699	0	2.547	2.088
QOIL	Total oil production (including gas condensate) in million bbls per year	27.867	591.595	0	19.018	905.95
QGAS	Total gas production in million mcf per year	186.974	12.977	0	1,105	5,336.4
GASWELLS	Number of producing gas wells	91	11	0	604	42,772
OILWELLS	Number of producing oil wells	227	403	0	112	191,300
<u>Cost</u>						
CBBL	Variable operating cost per unit of oil production in dollars per barrel	2.18	0	0	0.91	0
CMCF	Variable operating cost per unit of gas production in dollars per mcf	0	0	0	0.099	0
CWGAS	Variable operating cost in million dollars per producing oil well	0.041	0.041	0	0	0.023
CWOIL	Variable operating cost in million dollars per producing gas well	0.146	0.62	0	0	0.023
DEVELOP	Nondrilling development costs in millions of dollars	0	1,667.0	0	58.6	2,282.3
DRILLING	Cost of exploratory and development drilling in dollars per foot	231	445	914	501	86
EXPLORE	Predrilling seismic and geologic exploratory activity expressed in millions of dollars	8.4	204.9	204.8	139	510
FOOTAGE	Depth of exploration and development drilling in millions of feet	.174	2.003	.033	2.9	126.4
CENTSBBL	Minimum nominal severance tax rate in dollars per bbl of oil ^a	0.6	0.8	0.8	0 ^e	0.046
CENTSMCF	Minimum nominal severance tax rate in dollars per mcf of gas ^b	0.064	0.064	0.064	0	0

Variable	Definition	1982 VALUE				
		ALASKA			TEXAS	
		Cook Inlet	North Slope	Other	Off- shore	On- shore
<u>State Severance Tax</u>						
ELGASEXP	Exponent in economic limit factor formula for gas production ^c	1	0	0	0	0
ELOILEXP	Exponent in economic limit factor formula for oil production; expressed in millions of well days per year times 460 ^c	0.1679	0.1679	0.1679	0	0
GASPCT	Nominal gas severance tax rate expressed as a percent of value of taxable production at the well head ^d	0.1	0.1	0	0.011 ^e	0.075
INEFFECT	Switch variable equal to 1 from 1979 to 1982 when Alaska Special 9.4 percent corporate income tax was in effect; zero otherwise	0	0	0	0	0
LOWOIL	Fraction of QOIL produced from Alaska fields coming into commercial production after July 15, 1981 for which Alaska severance tax rate equals 12.25 percent for first five years of production (instead of default 15 percent—see OILPCT1). ^f	0	.055	0	0	0
OILPCT1	Nominal severance tax rate expressed as a percent of value of taxable production at the well head ^g	0.15	0.15	0.15	0.004	0.046
<u>Windfall Profits Tax</u>						
FREXEMPT	Fraction of QOIL from fields exempt from the windfall profits tax ^h	0.002	.055	0	0.034	0.034
FRTIER2	Fraction of QOIL classified as Tier 2 (heavy oil and production from stripper property)	0	0	0	0	0.20 ⁱ
FRTIER3	Fraction of QOIL classified as Tier 3 (newly discovered and incremental tertiary oil) ^j	0	0	0	0.56	0.237
FRTIERN	Fraction of QOIL classified as newly discovered oil ^k	0	0	0	0.56	0.231
PHASEOUT	Phaseout factor for windfall profits tax (percent) ⁱ	1.0	1.0	1.0	1.0	1.0
POIL79T1	Base price in 1979 for Tier 1 Oil in dollars per bbl	5.83 ^m	12.49 ⁿ	0	12.81 ^o	12.81 ^o
POIL79T2	Base price in 1979 for Tier 2 Oil in dollars per bbl ^o	15.2	15.2	0	15.2	15.2

		1982 VALUE				
		ALASKA			TEXAS	
Variable	Definition	Cook Inlet	North Slope	Other	Off- shore	On- shore
<u>Windfall Profits Tax (Continued)</u>						
POIL79T3	Base price in 1979 for Tier 3 Oil in dollars per bbl ^o	16.55	16.55	0	16.55	16.55
TARIFF	TAPS tariff in dollars per bbl ^p	6.26	6.21 ^q	0	6.26	6.26
TXOILROY	Oil royalty shares subject to windfall profits tax (fraction of OILROY) ^r	0.112	0	0	0.909	0.002
WPTRATEN	Nominal windfall profit tax rate for newly discovered oil			— .275 —		
<u>Other Taxes, Allowances, and Credits</u>						
DEFLATOR	GNP implicit price deflator (Index, 1972 = 1.0)			— 2.069 —		
DEPALLRT	Percentage depletion rate used in the determination of the depletion allowance (percent) ^s			— 0.18 —		
FRINDEPN	Fraction of total production from independent producers after 1975 ^t	0.013	0.013	0.013	0.6	0.6
FCORPRT	Marginal federal corporate income tax rate (percent)			— 0.46 —		
INVTXCR	Federal investment tax credit. The fraction of tangible, non-exploratory capital investment that may be sub- tracted from the corporate income tax liability ^u			— 0.10 —		
SCORPRT	Marginal state corporate income tax rate ^v	.094	.094	.094	0	0
<u>Lease Payments</u>						
BONUS	Upfront cash payment for oil and gas leases in millions of dollars ^w	1.3	112.6	2,056.3	639.2	62.0
EXPLINCR	Exploration incentive credit in millions of dollars ^x	0	0	0	0	0
NPSRATE	Net profit share fraction in lease terms (percent)	0	0	0	0	0
GASROY	Gas royalty shares in millions of dollars ^w	17.2	126.2	0	575.8	91.9
OILROY	Oil royalty shares in millions of dollars ^w	97.5	1,423.2	0	102.6	257.5
RENTAL	Lease rental payment in millions of dollars per year ^w	3.3	4.3	4.1	19.4	7.4

Endogenous Variables

<u>Variable</u>	<u>Definition</u>
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Production, Income, and Rent

CUMQOIL	Cumulative oil production in millions of barrels per year.
NPR	Present discounted value of cumulative net operating revenues in millions of dollars.
PDAFTAX	Present discounted value of cumulative net economic rent to producers after deducting from total revenue: operating costs, state and federal corporate income taxes, severance taxes, royalty payments, windfall profit taxes, and other excise taxes; bonus payments and capital costs measured on a cash basis in millions of dollars.
PDAFTAX1	Same as PDAFTAX except that bonus payments and capital costs are apportioned annually over the total quantity of expected oil production in millions of dollars. The numeric suffix pertains to the degree of smoothing in the recovery formula.
PDAFTAX2	
PDAFTAX3	
PDAFTPRO	Present discounted value of cumulative after-tax producer profits in millions of dollars.
PDCARENT	Present discounted value of cumulative net cash revenues after deducting operating costs, capital costs (measured on a cash basis), and property taxes, but before all other tax and lease payments in millions of dollars. Same as PDOPRENT except for the method of apportioning capital costs.
PDINCOME	Present discounted value of cumulative net economic rent to producers before deducting state and federal corporate income taxes and after deducting operating costs, capital costs, all other taxes and lease payments, including net profit share lease payments expressed in millions of dollars. PDINCOME is the same as PDAFTAX except that PDAFTAX deducts state and federal corporate income taxes.
PDINC1	Same as PDINCOME except that bonus payments and capital expenditures are apportioned annually over the total quantity of expected oil production expressed in millions of dollars; the numeric suffix pertains to the degree of smoothing in payment recovery formula.
PDINC2	
PDINC3	
PDNRENT1	Present discounted value of cumulative net cash revenues after deducting operating costs and capital costs apportioned annually over the total quantity of expected oil production in millions of dollars per year. Numeric suffix pertains to the degree of smoothing in capital recovery formula.
PDNRENT2	
PDNRENT3	
PONV1	Present discounted value of cumulative net economic rent to producers before deducting state and federal corporate income taxes in millions of dollars. Amounts deducted from gross revenue include capital costs apportioned annually over the total quantity of expected oil production; operating costs, all other taxes
PONV2	
PONV3	

<u>Variable</u>	<u>Definition</u>
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(severance, windfall profits, property, and conservation), and all lease payments except net profit sharing. These variables are the same as PDINC1, PDINC2, and PDINC3 except that net profit shares are not deducted. Numeric suffix pertains to the degree of smoothing in capital recovery formula.

PDOPRENT	Present discounted value of cumulative net cash revenues after deducting operating costs and the discounted cash value of cumulative capital services in millions of dollars.
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PDREV	Present discounted value of cumulative oil and gas revenues in millions of dollars.
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PDSRPLUS	Present discounted value of the cumulative operating surplus in millions of dollars.
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PDVOP	Present discounted value of cumulative net cash operating revenues after deducting (1) operating costs, (2) lease payments and excise taxes (i.e., royalties, severance taxes, windfall profits taxes, and conservation taxes), and (3) the annual cash value of cumulative capital services plus noncontingent (bonus and rental) lease payments in millions of dollars.
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Cost

F	Total present value of cumulative capital expenditures, including bonus and rental payments in millions of dollars.
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RF	Total present value of cumulative capital expenditures, excluding lease payments, in millions of dollars.
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RF1	Present value of annual capital expenditures in millions of dollars per year. Numeric suffix pertains to degree of smoothing in capital recovery formula.
RF2	
RF3	

Tax Payments

PDEXCISE	Present discounted value of cumulative lease and tax payments tied to the level of production, including: royalty payments, severance taxes, windfall profit taxes, and conservation taxes in millions of dollars.
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RESTAX	Reserves tax in millions of dollars per year.
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TAXBASE	Annual value of taxable property (not including reserves) after deducting depreciation in millions of dollars.
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TAXINCF	Taxable income for federal tax purposes in millions of dollars per year.
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<u>Variable</u>	<u>Definition</u>
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Lease Payments

BONUSRT1	Present discounted value of bonus payments apportioned annually over the total quantity of expected oil production in millions of dollars per year. Numeric suffix pertains to degree of smoothing in the bonus recovery formula.
BONUSRT2	
BONUSRT3	
POBONUS	Present discounted value of cumulative bonus and rental lease payments in millions of dollars.

Definition Variables

Production, Income, and Rent

AFTAX1	Net economic rent to producers after deducting all lease and tax payments including NPS and state and federal corporate income tax in millions of dollars. Fixed costs apportioned annually over the total expected oil production. Numeric suffix pertains to degree of smoothing in capital and bonus payment recovery formula. Comparable to funds available for retained earnings and share holder distribution.
AFTAX2	
AFTAX3	
AFTPROF	After-tax producer profits in millions of dollars per year.
CAAFTAX	Net economic rent to producers after deducting all lease and tax payments including NPS and state and federal corporate income tax in millions of dollars per year. Same as AFTAX _i (i = 1,2,3) except that fixed costs are measured on a cash basis.
CAINCOME	Net economic rent to producers after deducting all lease and tax payments (excluding state and federal corporate income tax) in millions of dollars per year. Fixed costs deducted on a cash basis. Equal to CAAFTAX before deducting corporate income taxes.
CARENT	Total economic rent where operating and fixed capital costs are measured on a cash basis (equals revenue minus fixed capital and variable operating costs); expressed in millions of dollars per year.
CAVALUE	Economic rent net of excise taxes and lease payments, before deducting net profit shares, in millions of dollars per year. Equals CAINCOME before deducting net profit shares.
FRTIER1	Fraction of QOIL classified as Tier 1. Equal to taxable crude other than heavy oil and stripper oil (Tier 2), and newly discovered and incremental tertiary oil (Tier 3).

<u>Variable</u>	<u>Definition</u>
INCOME1 INCOME2 INCOME3	Net economic rent to producers after deducting all lease and tax payments except corporate income taxes in millions of dollars per year. Capital costs and bonus payments apportioned annually over total quantity of expected oil production. Numeric suffix pertains to degree of smoothing in the capital and bonus payment recovery formula. Equal to AFTAX _i (i = 1,2,3) before deducting corporate income taxes.
NETREV	Net operating revenue on a cash basis. Equal to total revenue minus royalties, excise tax payments, and operating costs in millions of dollars per year.
NEWOIL	Initial oil production for new fields in millions of barrels per year, for the purpose of apportioning capital recovery.
NRATE	Amortized bonus and rental charges in millions of dollars per barrel of NEWOIL.
NRENT1 NRENT2 NRENT3	Economic rent with annual recovery of capital costs over expected oil production in millions of dollars per year. Numeric suffix pertains to degree of smoothing in capital recovery formula.
NVALUE1 NVALUE2 NVALUE3	Net economic rent to producers before deducting state and federal corporate income taxes and NPS lease payments in millions of dollars per year. Fixed capital and bonus charges apportioned annually over expected oil production. Numeric suffix pertains to degree of smoothing in capital recovery formula.
OLDOIL	Amount of production from fields in production in prior years for apportioning capital costs, in millions of barrels per year. Equal to the product of production in the previous period and one minus the decline rate, GAMMA.
OPAFTAX	Net after tax cash income after deducting all lease and tax payments in millions of dollars per year. Fixed capital and bonus payments amortized over the total expected oil production.
OPINCOME	Net cash income after deducting all lease and tax payments except state and federal corporate income taxes in millions of dollars per year. Fixed capital and lease payments amortized over the total quantity of expected oil production. Equal to OPAFTAX before deducting corporate income taxes.
OPRENT	Economic rent where fixed capital costs measured as the present discounted value of cumulative net capital services in millions of dollars per year. Same as CARENT except that capital costs expressed in terms of net capital services (OPRENT) instead of fixed capital charges on a cash basis (CARENT).
OPVALUE	Cash income net of all costs and excise payments for leases and taxes before deducting NPS and corporate income tax payments in millions of dollars per year. Same as CAVALUE except that fixed capital charges are expressed as the present discounted annual value of cumulative net capital services.

<u>Variable</u>	<u>Definition</u>
PDVCASH	Present value of cumulative economic rent, excluding corporate income tax, with fixed costs measured as capital services, in millions of dollars.
REV	Gross cash revenue from oil and gas production in millions of dollars per year.
SRPLUS	Cash value of operating surplus; equal to gross revenue minus operating costs in millions of dollars per year.
<u>Cost</u>	
C	Operating cost in millions of dollars per year.
CAPITAL	Capital costs on a cash flow basis in millions of dollars per year.
INTANG	Intangible drilling costs in millions of dollars per year.
NCAPCOST	Share of total capital charges apportioned to the year of initial production, expressed in millions of dollars per year.
NCAPITAL	Share of real fixed capital charges apportioned to year of initial production, in millions of dollars per year.
<u>Tax Payments</u>	
CONSVTAX	Petroleum conservation tax. Equal in Alaska to 1/8 of one cent per barrel times the total quantity of production (QOIL). Expressed in millions of dollars per year. Called a "regulation tax" in Texas, with a rate of 3/16 of one cent per barrel.
CORPRATE	Combined effective state and federal corporate income tax rate (fraction).
CORPTXF	Federal corporate income taxes in millions of dollars per year.
CORPTXS	State corporate income taxes in millions of dollars.
DEPALLOW	Depletion allowance in millions of dollars per year.
ELFCALC	Calculated economic limit factor for oil production computed on the basis of the formula in sec. 43.55.013 of the Alaska Statutes.
ELFGAS	Effective economic limit factor for gas production (percent).
ELFOIL	Effective economic limit factor for oil production. Alaska Statutes formula. Equal to ELFCALC prior to 1982. After 1982, equal to 1 if ELFCALC is greater or equal to 0.7; otherwise, equal to ELFCALC (fraction).

<u>Variable</u>	<u>Definition</u>
EXCISE	The sum of all tax and lease payments that are tied to the level of production in millions of dollars per year. Includes royalty payments plus severance, windfall profits, and conservation taxes.
EXCSHR	Ratio of excise payments to total revenue (fraction).
EXTAXOIL	Nonroyalty oil exempt from federal windfall profits tax (severance tax deduction) in millions of barrels per year (up to a 15 percent maximum state severance tax share).
GASNOMRT	Nominal severance tax rate on gas property before application of economic limit factor. Equal to the greater of the cents-per-mcf or percent of value options in the Alaska severance tax formula. Expressed in dollars per mcf.
GASSEVRT	Effective severance tax rate on gas production (fraction).
GASSEVTX	State severance taxes on gas production, expressed in millions of dollars per year.
NETTXROY	Royalty oil net of windfall profit tax, in millions of dollars per year.
NPROPTAX	Present value of property tax charged to year of initial production. Equal to property-tax charges component of NCAPCOST; expressed in millions of dollars per year.
OILNOMRT	Nominal severance tax rate on oil property before application of economic limit factor. Equal to the greater of the cents-per-barrel or percent-of-value options in the Alaska severance tax formula. Expressed in dollars per barrel.
OILSEVRT	Effective severance tax rate on oil production (fraction).
OILSEVTX	State severance taxes on oil production, expressed in millions of dollars.
POILBAS1 POILBAS2 POILBAS3	Inflation-adjusted base price for tier 1, 2, or 3 oil in the windfall profits tax formula; expressed in millions of dollars per barrel.
PROPTAX	State oil and gas property taxes in millions of dollars per year.
TAPSADJ	Adjustment for Trans-Alaska Pipeline tariff in windfall profit tax formula, in dollars per barrel.
TAXINCS	Corporate taxable income under state guidelines in millions of dollars per year.
WINDPROF	Total windfall profit from oil production as defined for federal windfall profits tax, expressed in millions of dollars per year.
WPTAX	Windfall profits tax in millions of dollars per year.

<u>Variable</u>	<u>Definition</u>
WPTAXRT	Weighted average effective windfall profits tax rate.
WPTBASE1	Windfall profits associated with tier 1 oil in millions of dollars per year.
WPTBASE2	Windfall profits associated with tier 2 oil in millions of dollars per year.
WPTBASE3	Windfall profits associated with total tier 3 oil in millions of dollars per year.
WPTBASEN	Windfall profits associated with newly discovered portion of tier 3 oil in millions of dollars per year.

Lease Payments

EXROYOIL	Royalty oil production exempt from windfall profits tax in millions of barrels per year.
NBONUS	Present discounted value of bonus payments charged to year of initial production; expressed in millions of dollars per year.
NPS	Net profit share payments in millions of dollars per year.
NPS1	Net profit share payments assuming capital costs apportioned over expected oil production, in millions of dollars per year. Numeric suffix pertains to degree of smoothing in recovery formula.
NPS2	
NPS3	
NRENTAL	Present value of lease rental payments charged to year of initial production, expressed in millions of dollars per year.
NSHARE	Present discounted value of lease rental and bonus payments charged to year of initial production, expressed in millions of dollars per year.
RGAS	Effective royalty rate for gas production (fraction).
ROIL	Effective royalty rate for oil production (fraction).
ROYALTY	Total lease royalty payments for oil and gas production in millions of dollars per year.
S	Effective net profit share fraction; equal to zero until the discounted present value of cumulative net before-tax income is positive.
SEVTAX	Total state severance taxes from oil and gas production in millions of dollars per year.

Parameters

<u>Constant Term</u>	<u>Definition</u>	<u>1982 VALUE</u>				
		<u>ALASKA</u>			<u>TEXAS</u>	
		<u>Cook Inlet</u>	<u>North Slope</u>	<u>Other</u>	<u>Off- shore</u>	<u>On- shore</u>
CONSRATE	Oil conservation or regulation tax rate, dollars per barrel	.00125	.00125	.00125	0	.001875
DEF1979	Value of GNP price deflator in 1979, date of windfall profit tax base (index: 1972 = 1.00)			1.634		
DELTA	Real discount rate			0.10		
DEPRATE	Average nominal rate of asset depreciation			0.12		
GAMMA	Annual oil production decline rate			0.12		
PCINTAN	Fraction of total drilling cost that is intangible; for use in determination of federal corporate income tax			0.9		
PELGAS	Production at economic limit for gas in billion cubic feet per year	1.095	1.095	1.095	1.095	0.0365
PELOIL	Production at economic limit for oil in millions of barrels per year	0.1095	0.1095	0.1095	0.1095	0.001278
PROPRATE	Property tax rate (fraction)			.02		
WPTRATE1	Nominal windfall profit tax rate for tier 1 oil			0.7		
WPTRATE2	Nominal windfall profit tax rate for tier 2 oil			0.6		
WPTRATE3	Nominal windfall profit tax rate for tier 3 oil			0.3		
RESRATE	Reserves tax rate	0	0	0	0	0.02

DOCUMENTATION NOTES

aPrior to 1977, tax rate varied in Alaska depending on average daily production. Since 1977, equal to \$0.60 for old crude and \$0.80 for other oil in Alaska. Source: Alaska Statute 43.55.011.

bAlaska Statute 43.55.011.

cApplies only to oil production in the Alaska severance tax from 1977 to present. Source: Alaska Statute 43.55.013.

dIn Alaska, tax rate on gas was periodically increased from 1 to 10 percent since its inception in 1955. Source: Alaska Statute 43.55.011.

eOnly applies to production from state offshore leases. Adjusted on the basis of production from state offshore leases as a proportion of total Texas offshore production.

fAlaska Statute 43.55.011. Equal to Kuparuk production divided by total North Slope production for North Slope region.

gPrior to 1977, tax rate varied in Alaska depending on average daily production. Source for Alaska: Alaska Statute 43.55.011. Historically, Texas tax rate was constant at 4.6 percent. See note d.

hExempt oil includes Indian oil and Alaskan oil produced from fields north of the Arctic Circle (other than Sadlerochit), on the northerly side of the Alaska range and at least 75 miles from the TAPS. We ignore front-end exempt oil. We further assume that only gas production occurs on Native lands in the Cook Inlet onshore area. Thus, only production from Kuparuk as a proportion of total North Slope production applies. Source: Public Law 96-223, 96th Congress.

iAssuming 17 percent of production from stripper wells, 3 percent heavy oil. Source: Oil and Gas Journal, November 14, 1983, page 105.

Estimates of incremental tertiary oil derived from Oil and Gas Journal, February 20, 1984, 19-22; and April 2, 1984, 92-105.

For Texas, newly discovered oil computed using the formula:

$$FRTIERN_t = QOIL_t * (1 - FREXEMPT_t - FRTIER2_t) - (BASE * [1 - d]^t - 1979)$$

Where $BASE = QOIL_{1979} * (1 - FREXEMPT_{1979} - FRTIER2_{1979})$

d = decline rate, set to 0.15 (offshore), 0.12 (onshore)
 t = year

T E X A S

<u>Year</u>	<u>Newly Discovered Oil (Fraction)</u>		<u>Incremental Tertiary Oil (Fraction)</u>	
	<u>Off-shore</u>	<u>On-shore</u>	<u>Off-shore</u>	<u>On-shore</u>
1980	0	0.074	0	0.005
1981	0.375	0.151	0	0.005
1982	0.56	0.231	0	0.006

Aggregate net windfall revenue will not exceed \$227.3 billion. Once in effect, the phase-out percentage will reduce at 3 percent per month over a 33-month period. Because of stable world oil prices, we assume that the phase-out period will not begin until the latest possible target month--December 1990. The percentages are:

<u>Year</u>	<u>Phase-out (%)</u>
1982-89	100
1990	64
1991	28
1992-2020	0

Cook Inlet average price for May 1979; reflects state royalty price under long-term contract with Tesoro. Source: Alaska Department of Natural Resources, Royalty Accounting.

Equals the ceiling price that would have applied in May 1979 for Tier 1 oil. Source: Eppenbach and Erickson, 1981, page 21, note 3.

National average domestic oil prices. Source: Public Law 96-223.

PRequired for windfall profit adjustment for Alaska North Slope crude. A value of \$6.26 signifies no TAPS adjustment, so this value is used for other regions.

Average TAPS tariff for North Slope oil equaled:

<u>Year</u>	<u>Tariff</u>
1980	6.26
1981	6.21
1982	6.21
1983	5.46

SOURCE: Alaska Department of Revenue, Division of Petroleum Revenue.

Includes federal royalty shares.

TXOILROY (Fraction)

<u>Year</u>	<u>A L A S K A</u>			<u>T E X A S</u>	
	<u>Cook Inlet</u>	<u>North Slope</u>	<u>Other</u>	<u>Off- shore</u>	<u>On- shore*</u>
1980	0.121	0	0	0.772	0.002
1981	0.098	0	0	0.874	0.003
1982	0.112	0	0	0.909	0.002

*Excludes private onshore royalty shares.

Applies to producers that qualify under the Tax Reduction Act of 1975. Applies mainly to independent producers. Percentage depletions first enacted in 1918. Equal to:

<u>Year</u>	<u>Rate (%)</u>
1918-1968	27.5
1969-1980	22.0
1981	20
1982	18
1983	16
1984-2020	15

SOURCE: R.E. Megill, An Introduction to Exploration Economics (Tulsa, Petroleum Publishing Co., 1979).

†Peter Mieszkowski and Eric Toder, "Taxation of Energy Resources," in Fiscal Federalism and the Taxation of Natural Resources, Charles McLure and Peter Mieszkowski, ed., pages 65-92.

¶First enacted in 1962. Rates for periods shown as follows:

<u>Year</u>	<u>Credit Rate (%)</u>
1962-1966	7 percent
Oct 66-Mar 67	suspended
Apr 68-Mar 69	7 percent
Apr 69-Jul 71	terminated
Aug 71-1974	restored at 7 percent
1975-present	10 percent

After 1981 amendments for Accelerated Cost Recovery (ACR) method. We ignore further amendments in 1982.

SOURCE: Internal Revenue Service.

¶Texas has no corporate income tax.

¶Source: see Chapter II.

¶Pertains to certain Alaska state leases since 1979. Allows credit for expenditures for both exploratory wells and geophysical work on certain leases against royalty, rental, and severance tax payments for any other state lease. Credit varies from lease sale to lease sale but averaged \$600 per foot, not to exceed a certain proportion of total geophysical and exploration drilling costs. The rights to a credit are also assignable from one company to another.

2.0. Model Listing: HISTOIL-Offshore

Symbol Declarations

Endogenous:

AFTAX1 AFTAX2 AFTAX3 BONUSRT1 BONUSRT2 BONUSRT3 CAAFTAX CUMQOIL F NPR
OPAFTAX PDAFTAX PDAFTAX1 PDAFTAX2 PDAFTAX3 PDAFTPRO PDBONUS PDCARENT
PDEXCISE PDINCOME PDINC1 PDINC2 PDINC3 PDNRENT1 PDNRENT2 PDNRENT3
PDNV1 PDNV2 PDNV3 PDOPRENT PDREV PDSRPLUS PDVOP RESTAX RF RF1 RF2
RF3 TAXBASE TAXINCF TAXINCS

Definition:

AFTPROF C CAINCOME CAPITAL CARENT CAVALUE CONSVTAX CORPRATE CORPTXF
CORPTXS DEPALLOW ELFCALC ELFGAS ELFOIL EXCISE EXCSHR EXROYOIL
EXTAXOIL FRTIER1 GASNOMRT GASROY GASSEVRT GASSEVTX INCOME1 INCOME2
INCOME3 INTANG NBONUS NCAPCOST NCAPITAL NETREV NETTXROY NEWOIL
NPROPTAX NPS NPS1 NPS2 NPS3 NRATE NRENTAL NRENT1 - NRENT2 NRENT3
NSHARE NVALUE1 NVALUE2 NVALUE3 OILNOMRT OILPCT OILROY OILSEVRT OILSEVTX
OLDOIL OPINCOME OPRENT OPVALUE PDVCASH POILBAS1 POILBAS2 POILBAS3
PROPTAX REV ROYALTY S SEVTAX SRPLUS TAPSADJ T1981 WINDPROF WPTAX
WPTAXRT WPTAX1 WPTBASEN WPTBASE1 WPTBASE2 WPTBASE3

Exogenous:

BONUS CBBL CENTSBBL CENTSMCF CMCF CWGAS CWOIL DEFLATOR DEPALRT
DEVELOP DRILLING ELGASEXP ELOILEXP EXPLINCR EXPLORE FCORPRT FOOTAGE
FREXEMPT FRINDEPN FRTIERN FRTIER2 FRTIER3 GASPCT GASWELLS INEFFECT
INVTXCR LOWOIL NPSRATE OILPCT1 OILWELLS PGAS PHASEOUT POIL POIL79T1
POIL79T2 POIL79T3 QGAS QOIL RENTAL RGAS ROIL SCORPRT TARIFF TXOILROY
WPTRATEN YEAR

Parameter:

CONSRATE DEF1979 DELTA DEPRATE GAMMA PCTINTAN PELGAS PELOIL PROPRATE
RESRATE WPTRATE1 WPTRATE2 WPTRATE3

Equations

***** REVENUE AND COST *****

- 1: $REV == POIL * QOIL + PGAS * QGAS$
- 2: $C == CWOIL * OILWELLS + CBBL * QOIL + CWGAS * GASWELLS + CMC * QGAS$
- 3: $CAPITAL == EXPLORE + DEVELOP + DRILLING * FOOTAGE$
- 4: $SRPLUS == REV - C$
- 5: $GASROY == RGAS * PGAS * QGAS$
- 6: $OILROY == ROIL * POIL * QOIL$
- 7: $CONSVTAX == CONSRATE * QOIL$

***** EXCISE TAX SECTION *****

- 8: $OILPCT == IF\ YEAR\ LT\ 1982\ THEN\ OILPCT1\ ELSE\ OILPCT1 - 0.0275 * LOWOIL$

STATE SEVERANCE TAXES

- 9: $OILNOMRT == IF\ CENTSBBLE\ OILPCT * POIL\ THEN\ CENTSBBLE\ ELSE\ OILPCT * POIL$
- 10: $GASNOMRT == IF\ CENTSMCF\ GASPCT * PGAS\ THEN\ CENTSMCF\ ELSE\ GASPCT * PGAS$
- 11: $ELFGAS == IF\ QGAS\ LE\ PELGAS * GASWELLS\ THEN\ 0\ ELSE\ (1 - PELGAS * GASWELLS / QGAS) * ELGASEXP$
- 12: $ELFCALC == IF\ QOIL\ LE\ PELOIL * OILWELLS\ THEN\ 0\ ELSE\ (1 - PELOIL * OILWELLS / QOIL) * (ELOILEXP / PELOIL)$
- 13: $ELFOIL == IF\ YEAR\ LT\ 1982\ THEN\ ELFCALC\ ELSE\ (IF\ ELFCALC\ GE\ 0.7\ THEN\ 1.\ ELSE\ ELFCALC)$
- 14: $GASSEVRT == IF\ PGAS\ LE\ 0\ THEN\ 0\ ELSE\ GASNOMRT * ELFGAS / PGAS$
- 15: $OILSEVRT == IF\ POIL\ LE\ 0\ THEN\ 0\ ELSE\ OILNOMRT * ELFOIL / POIL$
- 16: $GASSEVTX == GASSEVRT * (1 - RGAS) * PGAS * QGAS$
- 17: $OILSEVTX == OILSEVRT * (1 - ROIL) * POIL * QOIL$

18: SEVTAX == OILSEVTX+GASSEVTX

19: FRTIER1 == IF YEAR LT 1980 THEN 0 ELSE 1-FREXEMPT-FRTIER2-FRTIER3

FEDERAL WINDFALL PROFITS TAX

20: TAPSADJ == IF TARIFF GE 6.26 THEN 0 ELSE 6.26-TARIFF

21: POILBAS1 == POIL79T1*(DEFLATOR/DEF1979)+TAPSADJ

22: POILBAS2 == POIL79T2*(DEFLATOR/DEF1979)+TAPSADJ

23: POILBAS3 == POIL79T3*(DEFLATOR*1.02015** (YEAR-1979)/DEF1979) +TAPSADJ

24: EXROYOIL == IF POIL LE 0 THEN 0 ELSE OILROY*(1-TXOILROY)/POIL

25: EXTAXOIL == IF OILSEVRT LT 0.15 THEN OILSEVRT*(1-ROIL)*QOIL ELSE
0.15*(1-ROIL)*QOIL

26: WPTBASE1 == IF POIL LE POILBAS1 THEN 0 ELSE (QOIL-EXTAXOIL-EXROYOIL)*
FRTIER1*(POIL-POILBAS1)

27: WPTBASE2 == IF POIL LE POILBAS2 THEN 0 ELSE (QOIL-EXTAXOIL-EXROYOIL)*
FRTIER2*(POIL-POILBAS2)

28: WPTBASE3 == IF POIL LE POILBAS3 THEN 0 ELSE (QOIL-EXTAXOIL-EXROYOIL)*
FRTIER3*(POIL-POILBAS3)

29: WPTBASEN == IF POIL LE POILBAS3 THEN 0 ELSE (QOIL-EXTAXOIL-EXROYOIL)*
FRTIERN*(POIL-POILBAS3)

30: WINDPROF == WPTBASE1+WPTBASE2+WPTBASE3

31: T1981 == IF YEAR GT 1982 THEN 0 ELSE 0.3

32: WPTAX1 == ((WPTRATE1-0.2*FRINDEPN)*WPTBASE1+(WPTRATE2-T1981*FRINDEPN)*
WPTBASE2+ (WPTRATEN*WPTBASEN+WPTRATE3*(WPTBASE3-WPTBASEN)))*PHASEOUT

33: WPTAX == IF TAXINCS LE 0 THEN 0 ELSE (IF WINDPROF GE 0.9*(TAXINCS+
WPTAX1) THEN 0.9*WPTAX1*TAXINCS/(WINDPROF-0.9*WPTAX1) ELSE WPTAX1)

34: WPTAXRT == IF POIL*(QOIL-EXROYOIL) LE 0 THEN 0 ELSE WPTAX/
(POIL*(QOIL-EXROYOIL))

***** CASH FLOW EQUATIONS *****

35: NETTXROY == (1-WPTAXRT*TXOILROY)*OILROY

36: ROYALTY == NETTXROY+GASROY
 37: EXCISE == ROYALTY+SEVTAX+WPTAX+CONSVTAX
 38: EXCSHR == IF REV EQ 0 THEN 0 ELSE EXCISE/REV
 39: NETREV == REV-EXCISE-C
 40: INTANG == PCTINTAN*DRILLING*FOOTAGE
 41: TAXBASE = TAXBASE(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA-DEPRATE)+
 CAPITAL-EXPLORE-INTANG
 42: PROPTAX == PROPRATE*TAXBASE
 43: F = F(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+BONUS+RENTAL+CAPITAL+PROPTAX
 44: RF == RF(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+CAPITAL+PROPTAX
 45: OPRENT == REV-(C+DELTA*RF)

***** CUMULATIVE CASH FLOWS BEFORE PROFIT SHARING AND INCOME TAXES *****

46: CARENT == REV-C-(CAPITAL+PROPTAX)
 47: CAVALUE == NETREV-(BONUS+RENTAL+CAPITAL+PROPTAX)
 48: OPVALUE == NETREV-DELTA*F
 49: CUMQOIL = CUMQOIL(-1)+QOIL
 50: PDBONUS = PDBONUS(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+BONUS+RENTAL
 51: PDREV = PDREV(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+REV
 52: PDSRPLUS = PDSRPLUS(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+SRPLUS
 53: PDEXCISE = PDEXCISE(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+EXCISE
 54: PDOPRENT = PDOPRENT(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+OPRENT
 55: PDCARENT = PDCARENT(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+CARENT

***** CAPITAL RECOVERY FACTORS *****

56: NPR = NPR(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+NETREV

```

57: PDVCASH == NPR-F
58: PDVOP = PDVOP(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+OPVALUE
59: OLDOIL == IF (1-GAMMA)*QOIL(-1) GT QOIL THEN QOIL ELSE (1-GAMMA)*
    QOIL(-1)
60: NEWOIL == QOIL-OLDOIL
61: NBONUS == BONUS(-7)*(DEFLATOR/DEFLATOR(-7))*EXP(DELTA*7)*GAMMA
62: NRENTAL == RENTAL(-4)*(DEFLATOR/DEFLATOR(-4))*EXP(DELTA*4)*GAMMA
63: NSHARE == NRENTAL+NBONUS
64: NRATE == IF NEWOIL LE 0 THEN 0 ELSE NSHARE/NEWOIL

```

***** PRORATED INVESTMENT USING CAPITAL RECOVERY FACTORS *****

```

65: NCAPITAL == CAPITAL(-2)*(DEFLATOR/DEFLATOR(-2))*EXP(DELTA*2)*GAMMA
66: NPROPTAX == PROPTAX(-1)*(DEFLATOR/DEFLATOR(-1))*EXP(DELTA*1)*GAMMA
67: NCAPCOST == NPROPTAX+NCAPITAL
68: BONUSRT1 = IF QOIL(-1) LE 0 THEN NSHARE ELSE OLDOIL/QOIL(-1)*
    BONUSRT1(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+NSHARE
69: BONUSRT2 = IF QOIL(-1) LE 0 THEN NSHARE ELSE OLDOIL/QOIL(-1)*
    BONUSRT2(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+0.5*NSHARE+0.25*NSHARE
    (-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+0.25*NSHARE(-2)*(DEFLATOR/
    DEFLATOR(-2))*(1+DELTA)*(1+DELTA)
70: BONUSRT3 = IF QOIL(-1) LE 0 THEN NSHARE ELSE OLDOIL/QOIL(-1)* BONUSRT3
    (-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+0.333*NSHARE(-2)*(DEFLATOR/
    DEFLATOR(-2))*(1+DELTA)*(1+DELTA)+0.333*NSHARE(-1)*(DEFLATOR/DEFLATOR
    (-1))*(1+DELTA)+0.333*NSHARE

```

***** CASH FLOWS ASSUMING PRORATED INVESTMENT *****

```

71: RF1 = IF QOIL(-1) LE 0 THEN NCAPCOST ELSE OLDOIL/QOIL(-1)*RF1(-1)*
    (DEFLATOR/DEFLATOR(-1))*(1+DELTA)+NCAPCOST

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72: RF2 = IF QOIL(-1) LE 0 THEN NCAPCOST ELSE OLDOIL/QOIL(-1)*RF2(-1)*
      (DEFLATOR/DEFLATOR(-1))*(1+DELTA)+0.5*NCAPCOST+0.25*NCAPCOST(-1)*
      (DEFLATOR/DEFLATOR(-1))*(1+DELTA)+0.25*NCAPCOST(-2)*(DEFLATOR/DEFLATOR
      (-2))*(1+DELTA)*(1+DELTA)

73: RF3 = IF QOIL(-1) LE 0 THEN NCAPCOST ELSE OLDOIL/QOIL(-1)*RF3(-1)*
      (DEFLATOR/DEFLATOR(-1))*(1+DELTA)+0.333*NCAPCOST(-2)*(DEFLATOR/DEFLATOR
      (-2))*(1+DELTA)*(1+DELTA)+0.333*NCAPCOST(-1)*(DEFLATOR/DEFLATOR(-1))*
      (1+DELTA)+0.333*NCAPCOST

74: NRENT1 == REV-C-RF1

75: NRENT2 == REV-C-RF2

76: NRENT3 == REV-C-RF3

77: NVALUE1 == REV-EXCISE-C-RF1-BONUSRT1

78: NVALUE2 == REV-C-EXCISE-RF2-BONUSRT2

79: NVALUE3 == REV-EXCISE-C-RF3-BONUSRT3

80: PDNRENT1 = PDNRENT1(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+NRENT1

81: PDNRENT2 = PDNRENT2(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+NRENT2

82: PDNRENT3 = PDNRENT3(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+NRENT3

```

***** NET PROFIT SHARING *****

```

83: PDNV1 = PDNV1(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+NVALUE1

84: PDNV2 = PDNV2(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+NVALUE2

85: PDNV3 = PDNV3(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+NVALUE3

86: S == IF PDVCASH LE 0 THEN 0 ELSE NPSRATE

87: NPS == S*CAVALUE

88: NPS1 == S*NVALUE1

89: NPS2 == S*NVALUE2

90: NPS3 == S*NVALUE3

91: CAINCOME == (1-S)*CAVALUE

```


92: OPINCOME == (1-S)*OPVALUE
 93: INCOME1 == (1-S)*NVALUE1
 94: INCOME2 == (1-S)*NVALUE2
 95: INCOME3 == (1-S)*NVALUE3
 96: PDINCOME = PDINCOME(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+CAINCOME

***** INCOME TAXES *****

97: PDINC1 = PDINC1(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+INCOME1
 98: PDINC2 = PDINC2(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+INCOME2
 99: PDINC3 = PDINC3(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+INCOME3
 100: TAXINCS = NETREV-PROPTAX-0.25*(BONUS+BONUS(-1)+BONUS(-2)+BONUS(-3)+
 RENTAL+RENTAL(-1)+RENTAL(-2)+RENTAL(-3)+CAPITAL+CAPITAL(-1)+CAPITAL
 (-2)+CAPITAL(-3))-NPS-RESTAX
 101: CORPTXS == INEFFECT*SCORPRT*TAXINCS-EXPLINCR*DRILLING*FOOTAGE
 102: TAXINCF = NETREV-RENTAL-EXPLORE-INTANG-PROPTAX-0.25*(BONUS+BONUS(-1)+
 BONUS(-2)+BONUS(-3)+CAPITAL+CAPITAL(-1)+CAPITAL(-2)+CAPITAL(-3)-
 EXPLORE-EXPLORE(-1)-EXPLORE(-2)-EXPLORE(-3)-INTANG-INTANG(-1)-INTANG
 (-2)-INTANG(-3))-CORPTXS-NPS-RESTAX
 103: DEPALLOW == IF TAXINCF LE 0 THEN 0 ELSE (IF DEPALLRT*REV LE 0.5*
 TAXINCF THEN FRINDEPN*DEPALLRT*REV ELSE FRINDEPN*0.5*TAXINCF)
 104: CORPTXF == FCORPRT*TAXINCF-DEPALLOW-INVTXCR*(CAPITAL-EXPLORE-INTANG)
 105: CORPRATE == IF TAXINCS EQ 0 THEN 0 ELSE (CORPTXF+CORPTXS)/TAXINCS
 106: CAAFTAX = CAINCOME-CORPTXF-CORPTXS-RESTAX
 107: OPAFTAX = OPINCOME-CORPTXF-CORPTXS-RESTAX
 108: AFTAX1 = INCOME1-CORPTXF-CORPTXS-RESTAX
 109: AFTAX2 = INCOME2-CORPTXF-CORPTXS-RESTAX
 110: AFTAX3 = INCOME3-CORPTXF-CORPTXS-RESTAX
 111: PDAFTAX = PDAFTAX(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+CAAFTAX

112: PDAFTAX1 = PDAFTAX1(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+AFTAX1
113: PDAFTAX2 = PDAFTAX2(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+AFTAX2
114: PDAFTAX3 = PDAFTAX3(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+AFTAX3
115: AFTPROF == TAXINCS-CORPTXF-CORPTXS-RESTAX
116: PDAFTPRO = PDAFTPRO(-1)*(DEFLATOR/DEFLATOR(-1))*(1+DELTA)+AFTPROF
117: RESTAX = RESRATE*(TAXINCS+ROYALTY)/(DELTA+GAMMA)

3.0. Data Sources for Cost Variables

TABLE D.1. SELECTED SOURCES FOR CAPITAL AND OPERATING COSTS BY REGION
(source, definition, range, and notes)

Capital Costs Variables				
Region	EXPLORE	DRILLING	FOOTAGE	DEVELOP
ALASKA Cook Inlet	1. AAPG, geologic and seismic crew months 1958-81 (Cook Inlet region estimated by ISER; Table 4) 2. SEG, geologic and seismic crew months by state, 1959-76 (land/marine distinction after 1967) 3. SEG, \$ per crew month 1964-76, land/marine (Table 9) 4. Mead, \$ per crew month in Gulf of Mexico, 1950-69, derived from SEG national data 5. U.S. Census, Total U.S. geological and geophysical expenditures, 1973-81.	1. Erickson and Latham, \$ per foot, 1957-75 (Tables 15, 15.A, 16) 2. JAS, \$ per foot, Alaska offshore, 1975-81, (this reflects mainly development drilling in Cook Inlet; see Table 13)	1. AOGCC, Total footage, 1959-82 (Cook Inlet region estimated by ISER; Table 12) 2. Nehring, average well depth for Alaska region, 1957-75 3. AOGCC, number of wells, 1959-82 (see Table 21)	1. Erickson and Latham, Platform investments in Cook Inlet, 1957-75 (Table 15) 2. LFD (PB Model), oil and gas field capital costs in Cook Inlet, 1958-82 (Table 17) 3. BPDH, total national leasing equipment costs, 1973-81 (divide by number of U.S. active wells to derive estimate of average development cost per well; multiply by number of wells from AOGCC) 4. Dames and Moore, development well cost estimates, 1980

Operating Cost Variables (CWOIL, CBBL, CWGAS, CMCF)

1. LFD (PB Model) Cook Inlet oil and gas operating costs, expressed either as \$/bbl, mcf, or \$/well, 1958-81.
2. Erickson and Latham, estimated total oil (and gas) operating costs in Cook Inlet can be expressed either as \$/bbl, mcf, or \$/well, 1958-1975, pegged in 1975, deflation factor for earlier years (Table 22).
3. AOGCC, number of active wells by type for Cook Inlet, 1959-82 (Table 21.A).

(Table D.1., Continued)

Capital Costs Variables

Region	EXPLORE	DRILLING	FOOTAGE	DEVELOP
ALASKA North Slope	1. AAPG, geologic and seismic crew months, 1958-81 (N. Slope region estimated by ISER; Table 4) 2. SEG, \$ per crew month, national average, land/marine, 1964-76 3. Mead, \$ per crew month (based on SEG), 1950-69 (Table 7) 4. NPC, \$ per crew month by Alaska regions, 1981 only (Table 6) 5. Beck, index of geo-physical costs per line mile for data acquisition Alaska region, 1975 only (Table 8)	1. JAS, Alaska onshore drilling cost per foot, 1975-81 (Table 13) 2. CER, drilling costs in \$ per foot, Alaska-Hawaii (fairly close to JAS figures above) 1969-82, Table 14 3. U.S. DOE, drilling cost index by well depth; estimates for onshore drilling, but exclude Alaska (may nevertheless reflect frontier onshore drilling) 1980-81 4. BPDH, total national expenditures onshore/offshore (from JAS), 1973-81; estimate of average drilling cost could be derived from national data on total footage 5. JAS, Index of U.S. avg. drilling costs to Alaska drilling costs, 1975-81, Table 13.A. 6. NPC, exploration well costs, 1981, Table E-1.	1. AOGCC, total footage, 1959-82 (N. Slope region estmd by ISER; Table 12) 2. OGJ, average U.S. well depth, 1954-82 3. Nehring, average well depth, Alaska region, 1936-75 4. JAS, average well depth, Alaska onshore/offshore 1975-81 [Could apply estimates from 2, 3, and 4, above, to data on number of wells from AOGCC, Table 21]	1. LFD (PB Model), oil and gas field capital costs, 1958-82, N. Slope region (Table 17) 2. NPC, nondrilling exploration well costs for 12,000-foot depth in N. Slope, 1981 (Table 18) 3. NPC, N. Slope field development costs of facilities, 1981 (Table 19) 4. Dames & Moore, development well cost estimates, 1980

Operating Cost Variables
(CWOIL, CBBL, CWGAS, CMCf)

1. LFD (PB Model) North Slope total operating costs, 1958-82 (Table 21) expressed in total \$.
2. AOGCC, number of active wells, 1959-82.
3. NPC, total operating expenses per initially productive well (\$/well), 1981 (Table 23).

(Table D.1., Continued)

Capital Costs Variables

Region	EXPLORE	DRILLING	FOOTAGE	DEVELOP
OTHER ALASKA (Includes Federal OCS)	1. AAPG, geologic and seismic crew months, ISER estimate for "other areas," 1958-81 (Table 4) 2. SEG, \$ per crew month national average land/marine, 1964-76 3. Mead, \$ per crew month (based on SEG), 1950-69 (Table 7) 4. NPC, \$ per crew month by Alaska regions, 1981 only (Table 6) 5. Beck, index on geo-physical cost per line mile for data acquisition, Alaska region,	1. JAS, Alaska onshore drilling costs per foot, 1975-81 (Table 13) 2. BPDH, U.S. average onshore drilling costs, 1953-81 (JAS derived). (These figures differ substantially from Alaska costs, 1975-81; need method of adjusting upward; see Table 13.A) 3. DOE, Drilling Cost Index by well depth, 4. CER drilling costs, Alaska-Hawaii region, 1969-82 (Table 14) 5. NPC, Exploration well costs for Alaska region, 1981	1. AOGCC, estimated drilling activity footage well depth for "Other Alaska" region, 1959-82 (Table 12) 2. OGJ, number of wells and total footage (derive average well depth) Alaska OCS, 1981-82 U.S. Total, 1954-82 3. Nehring, average well depth, Alaska region, 1936-75 4. JAS, average well depth Alaska onshore/offshore 1975-81 5. MMS, Federal offshore statistics, number of new wells, Alaska region, 1977-82	1. LFD (PB Model), oil and gas Field Capital Costs, "Other N. Slope," 1958-82 (Table 17) 2. NPC, nondrilling exploration well costs for 12,000-foot depth, 1981 (Table 18) 3. NPC, field development facilities costs, 1981 (Table 19) 4. Dames & Moore, development well cost estimates, 1980

Operating Cost Variables

(CWOIL, CBBL, CWGAS, CMCf)

(Zero operations, historically)

1. For Projections: Legislative Finance estimates for N. Slope or Cook Inlet regions, depending upon field location (See Table 21).
2. NPC, total operating expenses for initially productive wells, 1981, (Table 23).

(Table D.1., Continued)

Capital Costs Variables

Region	EXPLORE	DRILLING	FOOTAGE	DEVELOP
TEXAS OFFSHORE	- Note: AAPG data that is comparable to Alaska not available for Texas OCS and other regions - SEG, crew months for Texas marine geologic and seismic activity, 1959-76 (this variable may include state offshore activity; develop method to separate state on-shore/offshore) - Mead, \$ per crew month, 1950-76, based on SEG data for U.S. as a whole - U.S. Census, total U.S. geologic & geophysical expenditures, 1973-81 - AAPG offshore geophysical activity for the Upper Gulf Coast of Texas, 1975-82	- JAS, Texas offshore drilling cost per foot, 1975-81 - CER, drilling costs by cost region, Texas offshore, 1969-85 (comparable to JAS until 1978; then JAS higher) - BPDH, U.S. avg. offshore drilling costs, 1953-81, Table 13	- OGJ, Texas federal OCS, number of wells and total footage, 1981 - JAS, number of wells and total footage, Texas, federal OCS, 1975-82 - Nehring, total footage and number of exploratory wells for Western Gulf of Mexico, 1936-75 (derive estimate of avg. well depth; apply to number of wells) - MMS, federal offshore statistics, number of wells, 1950-82	- Mead, cost per well beyond Christmas tree, 1955-76 - MMS, federal offshore statistics, total active and shut-in wells, 1950-82 - Nehring, number of exploratory wells for the Western Gulf of Mexico, 1936-75 (include state offshore) - BPDH, total national leasing equipment cost divided by total U.S. active and shut in wells, 1973-81

Operating Cost Variables

(CWOIL, CBBL, CWGAS, CMCF)

- Mead, \$ per currently productive oil and gas well for Gulf of Mexico, 1954-76, extrapolate to 1982 using GNP deflator. (From JAS and Mead special survey of producers). Apply same series of gas well operating costs.

(Table D.1., Continued)

Capital Costs Variables

Region	EXPLORE	DRILLING	FOOTAGE	DEVELOP
TEXAS ONSHORE	1. SEG, geologic and seismic crew months for Texas land, 1967-76; excludes state offshore lands; also, this variable combines state and private leases 2. SEG, \$ per crew month, national average; land vs. marine, or weighted average, 1964-76 3. U.S. Census, total U.S. geologic & geophysical expenditures, 1973-81	1. JAS, Texas drilling cost per foot onshore (or offshore) 1975-81 2. CER, drilling cost per foot by cost region, 1969-85 (west, south-central, and Texas offshore) 3. JAS, U.S. average cost per foot, 1953-74, (Table 13) 4. DOE, drilling cost index by well depth, 1980-81 (13 onshore regions for contiguous U.S.)	1. JAS, total footage Texas onshore, 1975-81 (incl. state and private) 2. Texas RR Com., number of wells, total footage 1935-82 (regional breakdowns) 3. OGJ, footage and number of wells, U.S. total: 1954-82; Texas: 1981-82 4. Nehring, total footage for 12 regions, 1936-75, Permian Basin and North Central Texas	1. BPOH, total national leasing equipment costs, 1973-81 (divide by number of U.S. wells to derive estimate of average development cost per well; multiply by number of wells in region) 2. CER, production cost (i.e., capital expenditures) = 1.8 x drilling costs 3. AAPG, further investigation of monthly publications for report on Texas development costs 4. Mead, cost per well beyond Christmas tree, 1955-76

Operating Cost Variables

(CWOIL, CBBL, CWGAS, CMCF)

1. U.S. Census, total production expenditures, 1973-81 (could divide series by U.S. production or number of wells).
2. Gruy, stripper well production costs, \$ per year, 1944-79.

(Table D.1., Continued)

SOURCE CODE

AAPG	American Association of Petroleum Geologists
AOGCC	Alaska Oil and Gas Conservation Commission
BPDH	Basic Petroleum Data Handbook
CER	Council on Energy Resources, University of Texas
JAS	Joint Association Survey
LFD	State of Alaska, Legislative Finance Division
MMS	Department of Interior, Minerals Management Services
NPC	National Petroleum Council
OGJ	Oil and Gas Journal
SEG	Society of Exploration Geophysicists
DOE	United States Department of Energy

(Consult reference section in Appendix B for specific citations)

Table D.2 Characteristics of Data on Capital and Operating Cost by Variables

EXPLORE: Predrilling exploratory geophysical work, expressed as the product of crew months exploration activity and \$ millions per crew month.

Source	Regions Covered	Range of Data	Definition of Data	Method of Estimation	Comments
Mead and Sorensen, 1980, Table 30, p. 129	Gulf of Mexico OCS area	1950-69	\$ per crew month for marine seismic exploration	Survey	Bases on SEG <i>Geophysics</i> , Vols. 17-35 (data apply to average national marine activity)
Society of Exploration Geophysicists, 1964-76	National Average land/marine	1964-76	\$ per crew month for exploration activity	Survey	Continuation of above series cited in Mead (Note, land/marine distinction available after 1967.)
Society of Exploration Geophysicists, 1959-76	All states; federal OCS areas after 1967	1959-76	Crew months of exploration activity (seismic and gravity/magnetic)	Survey	
U.S. Census, 1982	National Total	1973-81	Total exploration expenditures by type (i.e., geologic, geophysical, lease rental, etc.)	Survey	Part of a larger series on exploration, development and production costs. (Note, on- and off-shore is mixed.)
American Association of Petroleum Geologists	Alaska regions	1958-82	Crew months geologic and seismic	Survey	A consistent series corresponding to Texas regions not available, historically. Further investigation required to ascertain status of AAPG data on crew months exploration in Texas.
Beck, 1977	Major U.S. OCS areas	1975	Index of geophysical costs per line mile for data acquisition		
National Petroleum Council, 1981	Alaska regions	1981	\$ per crew month		

(Table D.2, continued)

DRILLING: Cost of exploratory and development drilling in \$ per foot.

Source	Regions Covered	Range of Data	Definition of Data	Method of Estimation	Comments
Joint Association Survey (JAS) 1975-81	States, OCS regions, national total	1975-82	Total cost for drilling oil, gas, and dry wells (also have \$/foot)	Survey	
U.S. Census, 1982	National total	1973-81	Total expenditures for drilling and equipping wells for exploration and development phases	Survey	Not distinguish between onshore and offshore.
Basic Petroleum Data Handbook (BPDH), 1983	National total (onshore/offshore)	1959-81	Total expenditures by oil, gas, dry, and combined wells	Survey	Not have state breakdown; based on JAS.
Erickson and Latham, 1976	Cook Inlet	1957-75	Drilling cost by exploration and development phases (total and \$ per foot)	Count	
U.S. Department of Energy Info. Admin. (DOE), 1981	Contiguous U.S. plus 13 onshore regions (same as Texas RR Commission)	1980-81	Indexes and estimates of domestic well drilling costs for a given average well depth	Survey	Based on JAS. Excludes offshore areas and Alaska.
National Petroleum Council (NPC), 1981	Alaska regions	1981	Exploration well costs, oil production cost, transportation costs	Site-specific deductive analysis	Estimates, based on development characteristics; low, medium, high cases.
Council on Energy Resources (CER), 1978	Alaska-Hawaii, Alaska offshore	1969-82	Drilling cost per foot	Survey	Alaska-Hawaii assumed to reflect onshore conditions, only.

(Table D.2, continued)

C: Operating costs, expressed as either \$ millions per well { CWOLL
CWGAS and \$ millions per unit production: { CBBL
CMCF

Source	Regions Covered	Range of Data	Definition of Data	Method of Estimation	Comments
Mead and Sorensen, 1976	Gulf of Mexico	1954-76	\$ per currently productive oil and gas well	Survey	Based on JAS data; apply same series for both oil and gas wells; use GNP deflator to estimate operating costs in later years.
U.S. Census, 1982	National total	1973-81	Total production expenditures	Survey	Not distinguish between on- and offshore operations.
Legislative Finance Division, 1983	Alaska fields	1958-81	Total oil (gas) operating costs	NA	
Erickson and Latham, 1976	Cook Inlet	1958-1975	Total operating costs for oil and gas, separately	Count	Costs pegged at 1975 level and deflated at 3 percent per year for previous years.
Gruy, 1981	National average	1944-79	Cost per year for stripper wells	Survey	
National Petroleum Council, 1981	Alaska regions (excluding Cook Inlet)	1981	Total operating expenses per initially productive fields	Scenario	Used for base year start-up assumptions in NPC analysis.
Alaska Statutes	Alaska state	1977	Production per well at the economic limit (PEL)		PEL equals: 300 bbl/day for oil; 3,000 mcf/day for gas
Dames & Moore	Beaufort Sea; Northern Gulf; Western Gulf; Bering Norton	1976-80	Annual field operating costs		Best suited for projection.

(Table D.2, continued)

FOOTAGE: Depth of exploration and development drilling in millions of feet

Source	Regions Covered	Range of Data	Definition of Data	Method of Estimation	Comments
Joint Association Survey (JAS), 1975-82	State and federal OCS regions	1975-82	Number of wells and total footage drilled on oil, gas, and dry wells	Survey	
U.S. Department of Interior, Minerals Management Services, 1983	Federal OCS regions	1954-82	Number of active and shut-in wells	Count	This series requires estimate of average well depth.
Oil and Gas Journal, 1982	National total	1954-82	Total wells and footage	Unknown	Data not distinguish between on- and off-shore wells; state breakdown not available.
Oil and Gas Journal, 1982	State and federal OCS regions	1981-82	Total wells and footage	Unknown	Estimate for 1981, forecast for 1982.
Nehring, 1981	National summary, 12 regions including Alaska and Western Gulf of Mexico	1936-75	Total footage and number of exploratory wells	Survey	Based on AAPG data; not distinguish between on- and offshore for Alaska; Western Gulf of Mexico includes state offshore.
Alaska Oil and Gas Conservation Comm. 1959-82	Alaska oil and gas fields	1959-82	Exploratory and development drilling footage	Count	
Texas Railroad Commission, 1982	Ten districts onshore	1936-82	Number of wells, total footage	Count	

(Table D.2, continued)

DEVELOP: Non-drilling development costs, in \$ millions

Source	Regions Covered	Range of Data	Definition of Data	Method of Estimation	Comments
Mead and Sorensen, 1980	Gulf of Mexico	1955-76	Cost per well for equipment beyond Christmas tree, for initially productive wells	Survey	Based on JAS. Find product of cost per well (Mead) and number of wells (MMS) to determine DEVELOP.
U.S. Dept. of Interior, Minerals Management Services (MMS), 1983	Texas OCS	1950-82	Total active and shut-in producible-zone well completions	Count	
U.S. Census, 1982	National total	1973-81	Total development expenditure	Survey	
Erickson and Latham, 1976	Cook Inlet	1957-75	Platform investment in millions	Unknown secondary sources	
Basic Petroleum Data Handbook, 1983	National total	1973-81	Lease equipment costs beyond Christmas tree installation required for preliminary production	Survey	
Div. of Legislative Finance, 1983	Alaska regions	1958-82	Oil and gas field capital costs (excluding TAPS)	Count	
National Petroleum Council, 1981	Alaska regions	1981	Nondrilling exploration well costs for 12,000-foot depth	Scenario	Best suited for projection purposes, Alaska frontier OCS regions.
Dames & Moore 1976, 1979, 1980	Beaufort, Northern Gulf, Western Gulf, Bering Norton	1976-80	Platform costs, development well costs, pipeline, oil terminal, and LNG facility costs	Scenario	Best suited for projection purposes, Alaska Frontier OCS regions.

APPENDIX E

GENERATION AND DISTRIBUTION OF ECONOMIC RENT FROM OIL
AND GAS PRODUCTION BY ALASKA AND TEXAS REGION
BASE CASE SIMULATIONS

TABLE 2.1.
GENERATION AND DISTRIBUTION OF ECONOMIC RENT FROM
OIL AND GAS PRODUCTION, 1963 TO 1982
COOK INLET BASECASE
(MILLIONS OF CURRENT DOLLARS)

	<u>OIL PRODUCTION (MMBBLs)</u>	<u>GAS SALES (BCF)</u>	<u>TOTAL OIL AND GAS REVENUE</u>	<u>OPERATING COSTS</u>	<u>REAL CAPITAL COSTS</u>	<u>PROPERTY TAXES</u>	<u>TOTAL ECONOMIC RENT</u>	<u>OIL AND GAS ROYALTIES</u>
1963	10.7	4.5	33.8	2.1	30.1	0.0	1.5	4.1
1964	11.1	6.2	35.3	2.1	23.6	0.1	9.5	4.3
1965	11.1	7.3	35.9	2.3	55.5	0.6	-22.5	4.2
1966	14.4	11.3	46.7	3.4	86.0	1.0	-43.7	5.7
1967	29.1	14.4	94.8	6.6	95.5	1.2	-8.6	9.5
1968	66.2	17.3	191.1	14.8	142.1	1.6	32.6	23.0
1969	74.0	50.9	227.6	19.8	97.3	1.9	108.7	26.7
1970	83.6	111.6	279.1	24.3	31.5	2.0	221.3	32.9
1971	79.5	121.6	275.4	24.3	13.2	2.1	235.9	39.5
1972	72.9	125.6	253.9	24.5	28.5	2.2	198.8	36.5
1973	72.3	131.0	281.3	25.0	39.8	2.3	214.2	39.6
1974	70.6	128.9	369.3	25.3	44.7	2.6	296.7	52.1
1975	69.8	160.3	412.9	25.8	60.0	2.8	324.3	52.7
1976	63.4	166.1	383.5	31.9	60.9	3.0	287.7	49.9
1977	56.4	153.0	357.0	39.7	40.8	3.2	273.3	41.3
1978	50.5	163.5	362.3	49.7	50.3	3.5	258.8	42.9
1979	43.1	168.4	371.3	64.0	41.8	3.8	261.7	43.0
1980	36.3	160.4	452.3	70.8	34.9	4.1	342.5	49.7
1981	31.9	176.7	1062.0	95.9	37.0	4.4	924.7	128.3
1982	27.9	167.0	885.0	108.3	43.6	4.7	723.4	109.4

SOURCE: OUTPUT FILE HISTOIL COOK BASECASE

TABLE E.1. (CONTINUED)
 GENERATION AND DISTRIBUTION OF ECONOMIC RENT FROM
 OIL AND GAS PRODUCTION, 1963 TO 1982
 COOK INLET BASECASE
 (MILLIONS OF CURRENT DOLLARS)

	LEASE BONUS AND RENTAL PAYMENTS	STATE PRODUCTION TAXES	FEDERAL WINDFALL PROFITS TAX	PRE-TAX PRODUCERS' ECONOMIC RENT	FEDERAL INCOME TAX	STATE AND LOCAL INCOME AND RESERVES TAXES	AFTER TAX PRODUCERS' ECONOMIC RENT	AFTERTAX PRODUCERS' PROFITS
1963	8.2	0.3	0.0	-11.1	-8.0	0.0	-3.1	-10.9
1964	1.8	0.3	0.0	3.1	-4.1	0.0	7.2	-13.7
1965	6.3	0.3	0.0	-33.4	-9.8	0.0	-23.6	-7.7
1966	8.5	0.4	0.0	-58.3	-24.7	0.0	-33.6	5.9
1967	20.1	1.5	0.0	-39.8	-15.3	0.0	-24.4	16.9
1968	8.2	5.0	0.0	-3.6	-7.6	0.0	4.1	48.7
1969	1.2	8.1	0.0	72.6	29.8	0.0	42.8	26.6
1970	1.0	12.2	0.0	175.2	77.7	0.0	97.5	30.8
1971	1.4	12.8	0.0	182.1	84.1	0.0	98.0	38.7
1972	4.0	13.8	0.0	144.5	69.1	0.0	75.4	63.4
1973	27.1	12.2	0.0	135.3	74.1	0.0	61.2	91.4
1974	2.3	24.7	0.0	217.7	101.5	0.0	116.2	122.9
1975	1.2	27.2	0.0	243.3	113.5	0.0	129.8	139.1
1976	1.0	26.2	0.0	210.6	97.7	0.0	112.9	115.6
1977	0.7	32.0	0.0	199.3	94.8	0.0	104.6	93.2
1978	0.6	17.0	0.0	198.4	90.2	9.2	98.9	96.0
1979	0.5	13.7	0.0	204.5	84.8	18.6	101.1	94.3
1980	1.7	11.9	62.1	217.2	88.6	19.8	108.8	102.6
1981	7.5	15.3	450.9	322.6	141.0	15.2	166.4	167.3
1982	4.6	8.1	349.9	251.3	113.8	0.0	137.5	146.6

SOURCE: OUTPUT FILE HISTOIL COOK BASECASE

TABLE E.2.
GENERATION AND DISTRIBUTION OF ECONOMIC RENT FROM
OIL AND GAS PRODUCTION, 1964 TO 1982
NORTH SLOPE BASECASE
(MILLIONS OF CURRENT DOLLARS)

	<u>OIL PRODUCTION (MMBLS)</u>	<u>GAS SALES (BCF)</u>	<u>TOTAL OIL AND GAS REVENUE</u>	<u>OPERATING COSTS</u>	<u>REAL CAPITAL COSTS</u>	<u>PROPERTY TAXES</u>	<u>TOTAL ECONOMIC RENT</u>	<u>OIL AND GAS ROYALTIES</u>
1964	0.0	0.0	0.0	0.0	61.4	0.0	-61.4	0.0
1965	0.0	0.0	0.0	0.0	38.5	0.1	-38.6	0.0
1966	0.0	0.0	0.0	0.0	9.1	0.2	-9.3	0.0
1967	0.0	0.0	0.0	0.0	3.2	0.2	-3.5	0.0
1968	0.0	0.0	0.0	0.1	43.0	0.4	-43.4	0.0
1969	0.0	0.0	0.0	0.1	228.6	0.5	-229.1	0.0
1970	0.0	0.0	0.0	0.1	625.8	8.9	-634.9	0.0
1971	0.0	0.0	0.0	0.1	157.3	11.0	-168.4	0.0
1972	0.0	0.0	0.0	0.1	98.4	12.4	-111.0	0.0
1973	0.0	0.0	0.0	0.2	130.6	13.9	-144.7	0.0
1974	0.0	0.0	0.0	0.2	342.5	17.6	-360.2	0.0
1975	0.0	0.0	0.0	0.2	912.6	29.3	-942.1	0.0
1976	0.0	0.0	0.0	0.2	1266.5	51.1	-1317.8	0.0
1977	112.8	2.0	693.4	111.4	1096.1	70.7	-584.8	79.0
1978	398.2	7.2	2008.8	161.2	686.7	81.5	1079.4	224.8
1979	467.0	9.0	4909.5	204.3	650.6	92.8	3961.8	583.6
1980	555.6	10.9	9314.2	237.3	848.1	105.8	8123.1	1117.5
1981	556.5	11.6	12916.6	243.1	1997.7	136.5	10539.3	1573.2
1982	591.5	13.0	11666.5	250.3	2763.3	176.9	8476.0	1425.8

SOURCE: OUTPUT FILE HISTOIL NSLOPE BASECASE

TABLE E.2. (CONTINUED)
 GENERATION AND DISTRIBUTION OF ECONOMIC RENT FROM
 OIL AND GAS PRODUCTION, 1964 TO 1982
 NORTH SLOPE BASECASE
 (MILLIONS OF CURRENT DOLLARS)

	LEASE BONUS AND RENTAL PAYMENTS	STATE PRODUCTION TAXES	FEDERAL WINDFALL PROFITS TAX	PRE-TAX PRODUCERS' ECONOMIC RENT	FEDERAL INCOME TAX	STATE AND LOCAL INCOME AND RESERVES TAXES	AFTER TAX PRODUCERS' ECONOMIC RENT	AFTERTAX PRODUCERS' PROFITS
1964	4.9	0.0	0.0	-66.3	-31.4	0.0	-34.9	4.0
1965	7.2	0.0	0.0	-45.8	-18.9	0.0	-27.0	-19.7
1966	1.1	0.0	0.0	-10.4	-5.7	0.0	-4.7	-33.5
1967	2.6	0.0	0.0	-6.1	-4.3	0.0	-1.7	-27.9
1968	1.4	0.0	0.0	-44.8	-21.1	0.0	-23.7	-5.8
1969	901.6	0.0	0.0	-1130.8	-218.8	0.0	-911.9	-79.4
1970	1.4	0.0	0.0	-636.3	-263.8	0.0	-372.5	-197.2
1971	1.5	0.0	0.0	-169.9	-210.1	0.0	40.2	-291.1
1972	1.5	0.0	0.0	-112.5	-205.5	0.0	93.0	-311.1
1973	1.7	0.0	0.0	-146.3	-124.0	0.0	-22.4	-144.7
1974	1.8	0.0	0.0	-362.0	-158.1	0.0	-203.9	-43.5
1975	1.7	0.0	0.0	-943.8	-348.0	0.0	-595.8	-54.1
1976	1.4	0.0	0.0	-1319.2	-446.3	0.0	-872.9	-269.7
1977	1.3	62.2	0.0	-727.3	-324.0	0.0	-403.2	-211.8
1978	1.1	265.5	0.0	588.0	74.7	13.3	799.9	195.9
1979	568.4	493.2	0.0	2316.5	965.8	231.9	1118.8	1269.7
1980	15.2	933.2	700.5	5356.7	2050.7	493.8	2812.2	2708.6
1981	3.3	1411.3	2445.8	5105.8	2290.7	278.0	2537.2	3345.4
1982	116.9	1520.5	1113.6	4299.2	2148.1	0.0	2151.1	3290.4

SOURCE: OUTPUT FILE HISTOIL NSLOPE BASECASE

TABLE E.3.
GENERATION AND DISTRIBUTION OF ECONOMIC RENT FROM
OIL AND GAS PRODUCTION, 1963 TO 1982
OTHER ALASKA BASECASE
(MILLIONS OF CURRENT DOLLARS)

	<u>OIL PRODUCTION (MMBBLs)</u>	<u>GAS SALES (BCF)</u>	<u>TOTAL OIL AND GAS REVENUE</u>	<u>OPERATING COSTS</u>	<u>REAL CAPITAL COSTS</u>	<u>PROPERTY TAXES</u>	<u>TOTAL ECONOMIC RENT</u>	<u>OIL AND GAS ROYALTIES</u>
1963	0.0	0.0	0.0	0.0	8.8	0.0	-8.8	0.0
1964	0.0	0.0	0.0	0.0	5.2	0.0	-5.2	0.0
1965	0.0	0.0	0.0	0.0	4.6	0.0	-4.6	0.0
1966	0.0	0.0	0.0	0.0	7.3	0.0	-7.3	0.0
1967	0.0	0.0	0.0	0.0	10.4	0.0	-10.4	0.0
1968	0.0	0.0	0.0	0.0	10.6	0.0	-10.6	0.0
1969	0.0	0.0	0.0	0.0	18.2	0.0	-18.3	0.0
1970	0.0	0.0	0.0	0.0	20.3	0.1	-20.4	0.0
1971	0.0	0.0	0.0	0.0	12.6	0.1	-12.7	0.0
1972	0.0	0.0	0.0	0.0	15.2	0.1	-15.2	0.0
1973	0.0	0.0	0.0	0.0	18.7	0.1	-18.8	0.0
1974	0.0	0.0	0.0	0.0	70.8	0.1	-70.9	0.0
1975	0.0	0.0	0.0	0.0	125.7	0.3	-125.9	0.0
1976	0.0	0.0	0.0	0.0	85.1	0.3	-85.4	0.0
1977	0.0	0.0	0.0	0.0	91.6	0.4	-92.0	0.0
1978	0.0	0.0	0.0	0.0	83.5	0.4	-84.0	0.0
1979	0.0	0.0	0.0	0.0	92.7	0.5	-93.2	0.0
1980	0.0	0.0	0.0	0.0	179.9	0.6	-180.6	0.0
1981	0.0	0.0	0.0	0.0	269.6	0.8	-270.5	0.0
1982	0.0	0.0	0.0	0.0	235.0	0.9	-235.9	0.0

SOURCE: OUTPUT FILE HISTOIL AKOTHER BASECASE

TABLE E.3. (CONTINUED)
 GENERATION AND DISTRIBUTION OF ECONOMIC RENT FROM
 OIL AND GAS PRODUCTION, 1963 TO 1982
 OTHER ALASKA BASECASE
 (MILLIONS OF CURRENT DOLLARS)

	LEASE BONUS AND RENTAL PAYMENTS	STATE PRODUCTION TAXES	FEDERAL WINDFALL PROFITS TAX	PRE-TAX PRODUCERS' ECONOMIC RENT	FEDERAL INCOME TAX	STATE AND LOCAL INCOME AND RESERVES TAXES	AFTER TAX PRODUCERS' ECONOMIC RENT	AFTERTAX PRODUCERS' PROFITS
1963	0.1	0.0	0.0	-8.8	-4.7	0.0	-4.2	-5.3
1964	0.2	0.0	0.0	-5.4	-2.8	0.0	-2.5	-6.2
1965	0.0	0.0	0.0	-4.6	-2.4	0.0	-2.3	-5.1
1966	0.5	0.0	0.0	-7.8	-3.8	0.0	-4.0	-2.9
1967	0.6	0.0	0.0	-11.0	-5.3	0.0	-5.7	-1.9
1968	3.7	0.0	0.0	-14.3	-5.8	0.0	-8.5	-3.6
1969	0.8	0.0	0.0	-19.0	-9.3	0.0	-9.8	-3.8
1970	0.7	0.0	0.0	-21.1	-10.2	0.0	-10.9	-6.2
1971	0.8	0.0	0.0	-13.4	-7.0	0.0	-6.4	-9.9
1972	0.7	0.0	0.0	-16.0	-7.8	0.0	-8.2	-9.6
1973	0.0	0.0	0.0	-18.8	-9.2	0.0	-9.7	-8.2
1974	0.9	0.0	0.0	-71.8	-33.7	0.0	-38.1	3.7
1975	0.9	0.0	0.0	-126.8	-57.3	0.0	-69.5	-1.2
1976	561.8	0.0	0.0	-647.1	-105.0	0.0	-542.1	-111.2
1977	402.0	0.0	0.0	-494.0	-154.5	0.0	-339.5	-180.6
1978	3.4	0.0	0.0	-87.4	-144.0	-15.9	72.6	-179.0
1979	491.7	0.0	0.0	-584.8	-191.5	-42.6	-350.7	-219.3
1980	113.4	0.0	0.0	-293.9	-183.0	-34.3	-76.6	-147.9
1981	8.1	0.0	0.0	-278.6	-187.6	-14.6	-76.3	-109.1
1982	2060.4	0.0	0.0	-2296.3	-417.2	0.0	-1879.1	-446.5

SOURCE: OUTPUT FILE HISTOIL AKOTHER BASECASE

TABLE E.4.
GENERATION AND DISTRIBUTION OF ECONOMIC RENT FROM
OIL AND GAS PRODUCTION, 1963 TO 1982
TEXAS ONSHORE BASECASE
(MILLIONS OF CURRENT DOLLARS)

	<u>OIL PRODUCTION (MMBBLs)</u>	<u>GAS SALES (BCF)</u>	<u>TOTAL OIL AND GAS REVENUE</u>	<u>OPERATING COSTS</u>	<u>REAL CAPITAL COSTS</u>	<u>PROPERTY TAXES</u>	<u>TOTAL ECONOMIC RENT</u>	<u>OIL AND GAS ROYALTIES</u>
1963	977.1	5994.0	3651.3	1762.0	1101.0	12.6	775.7	16.3
1964	988.9	6459.2	3734.6	1776.9	1063.3	18.4	875.9	16.4
1965	1057.1	6609.1	3981.7	1772.0	1109.5	24.7	1075.6	18.4
1966	1055.4	6890.2	4030.4	1760.2	1021.9	30.7	1217.7	18.3
1967	1116.9	7028.1	4289.4	1942.7	942.9	36.2	1367.6	19.7
1968	1129.8	7194.4	4405.7	1903.4	867.3	41.8	1593.2	22.6
1969	1148.8	7615.2	4731.0	2068.3	870.7	47.9	1744.1	23.9
1970	1246.8	8093.7	5254.9	2006.4	882.7	54.4	2311.4	24.4
1971	1220.7	8315.7	5587.0	2155.7	864.2	60.9	2506.2	26.2
1972	1299.2	8380.8	5895.8	2096.7	946.3	67.6	2785.2	24.7
1973	1292.4	8262.9	6881.8	2192.2	1046.3	76.0	3567.3	24.3
1974	1260.1	7900.8	11137.0	2396.4	1643.4	90.2	7007.0	36.0
1975	1220.2	7264.8	13180.2	2615.0	2548.4	111.1	7905.6	124.8
1976	1187.7	6985.9	14676.7	2828.6	2901.3	131.1	8815.8	161.2
1977	1134.4	6783.0	15760.5	2927.7	3741.8	155.5	8935.5	201.4
1978	1069.5	6146.2	15988.3	3391.9	4689.7	189.2	7717.5	194.0
1979	1012.0	6454.6	20378.6	3693.7	5129.5	225.9	11329.5	239.0
1980	964.9	6372.9	30696.2	4260.4	7868.8	283.0	18284.0	305.4
1981	929.0	6083.2	42942.8	4707.0	13402.9	369.6	24463.3	411.8
1982	905.9	5336.4	39785.2	5384.1	13660.3	451.5	20289.4	349.3

SOURCE: OUTPUT FILE HISTOIL TXONSHR BASECASE

TABLE E.4. (CONTINUED)
GENERATION AND DISTRIBUTION OF ECONOMIC RENT FROM
OIL AND GAS PRODUCTION, 1963 TO 1982
TEXAS ONSHORE BASECASE
(MILLIONS OF CURRENT DOLLARS)

	LEASE BONUS AND RENTAL PAYMENTS	STATE PRODUCTION TAXES	FEDERAL WINDFALL PROFITS TAX	PRE-TAX PRODUCERS' ECONOMIC RENT	FEDERAL INCOME TAX	STATE AND LOCAL INCOME AND RESERVES TAXES	AFTER TAX PRODUCERS' ECONOMIC RENT	AFTERTAX PRODUCERS' PROFITS
1963	8.8	190.6	0.0	560.0	227.7	42.7	289.7	182.8
1964	11.7	196.1	0.0	651.7	271.4	50.8	329.5	220.1
1965	13.2	208.8	0.0	835.1	346.1	71.8	417.1	353.9
1966	15.4	212.3	0.0	971.6	422.9	78.4	470.3	343.0
1967	7.3	225.2	0.0	1115.3	460.4	86.6	568.4	385.7
1968	9.9	231.6	0.0	1329.1	555.1	102.7	671.3	449.0
1969	8.1	248.7	0.0	1463.4	619.0	119.2	725.2	548.9
1970	7.4	276.5	0.0	2003.2	881.8	168.2	953.2	776.0
1971	7.0	296.6	0.0	2176.3	957.8	182.9	1035.7	844.7
1972	5.4	312.1	0.0	2443.0	1061.0	210.1	1171.9	1015.6
1973	12.0	363.9	0.0	3167.1	1383.3	275.6	1508.2	1348.1
1974	32.5	583.6	0.0	6354.8	2818.3	577.3	2959.3	2918.7
1975	23.6	708.1	0.0	7049.1	3124.3	681.8	3243.0	3568.8
1976	31.4	811.8	0.0	7811.4	3435.6	737.1	3638.7	3774.5
1977	37.7	892.6	0.0	7803.7	3397.4	753.7	3652.6	3938.4
1978	48.1	901.7	0.0	6573.7	2872.1	666.7	3034.9	3600.6
1979	33.4	1146.2	0.0	9910.8	4073.6	930.0	4907.2	4986.9
1980	41.8	1672.9	2514.6	13749.5	1881.5	1380.6	10487.3	11619.5
1981	169.8	2269.2	7752.5	13860.0	1849.5	1666.5	10343.9	14404.0
1982	69.4	2136.2	5459.8	12274.6	1548.8	1355.0	9370.8	11651.6

SOURCE: OUTPUT FILE HISTOIL TXONSHR BASECASE

TABLE E.5.
GENERATION AND DISTRIBUTION OF ECONOMIC RENT FROM
OIL AND GAS PRODUCTION, 1963 TO 1982
TEXAS OFFSHORE BASECASE
(MILLIONS OF CURRENT DOLLARS)

	<u>OIL PRODUCTION (MMBLS)</u>	<u>GAS SALES(BCF)</u>	<u>TOTAL OIL AND GAS REVENUE</u>	<u>OPERATING COSTS</u>	<u>REAL CAPITAL COSTS</u>	<u>PROPERTY TAXES</u>	<u>TOTAL ECONOMIC RENT</u>	<u>OIL AND GAS ROYALTIES</u>
1963	0.7	31.0	5.9	1.0	41.5	0.0	-36.7	0.8
1964	0.6	31.0	5.6	1.0	44.0	0.1	-39.4	0.7
1965	0.6	27.5	5.2	0.9	57.7	0.1	-53.5	0.8
1966	1.3	63.6	13.5	2.1	38.8	0.2	-27.6	2.4
1967	3.1	160.8	34.9	6.3	37.7	0.2	-9.4	5.5
1968	3.6	301.0	55.5	10.8	42.6	0.3	1.7	7.0
1969	3.0	238.0	45.9	8.4	46.2	0.5	-9.3	8.0
1970	3.0	264.0	50.2	9.5	30.6	0.7	9.4	8.5
1971	2.2	235.0	45.3	9.2	25.2	0.8	10.2	9.3
1972	2.5	277.0	55.3	10.7	17.8	0.8	26.0	10.5
1973	2.3	251.0	57.4	10.9	57.2	1.1	-11.7	10.5
1974	2.0	270.0	79.6	13.8	181.7	1.8	-117.7	14.6
1975	1.7	221.0	97.0	13.4	267.0	2.8	-186.3	26.4
1976	1.8	206.0	126.4	16.8	486.4	4.9	-381.8	36.0
1977	3.5	268.0	247.8	25.5	538.9	6.9	-323.6	50.6
1978	4.6	402.0	500.4	37.1	737.0	9.8	-283.6	115.2
1979	6.1	720.0	1219.8	56.0	789.9	13.4	360.5	215.5
1980	12.5	879.0	1927.8	82.3	1149.8	18.0	677.6	405.9
1981	16.1	967.0	2737.1	100.9	1533.7	23.9	1078.6	543.6
1982	19.0	1105.0	3430.1	126.7	1652.5	29.0	1621.9	678.4

SOURCE: OUTPUT FILE HISTOIL TXOFFSHR BASECASE

TABLE E.5. (CONTINUED)
 GENERATION AND DISTRIBUTION OF ECONOMIC RENT FROM
 OIL AND GAS PRODUCTION, 1963 TO 1982
 TEXAS OFFSHORE BASECASE
 (MILLIONS OF CURRENT DOLLARS)

	LEASE BONUS AND RENTAL PAYMENTS	STATE PRODUCTION TAXES	FEDERAL WINDFALL PROFITS TAX	PRE-TAX PRODUCERS' ECONOMIC RENT	FEDERAL INCOME TAX	STATE AND LOCAL INCOME AND RESERVES TAXES	AFTER TAX PRODUCERS' ECONOMIC RENT	AFTERTAX PRODUCERS' PROFITS
1963	3.3	0.3	0.0	-41.1	-24.7	0.0	-16.4	-26.4
1964	3.4	0.3	0.0	-43.8	-21.5	0.0	-22.3	-21.5
1965	54.3	0.3	0.0	-108.9	-33.1	0.0	-75.7	-25.3
1966	21.4	0.2	0.0	-51.6	-25.3	0.0	-26.2	-32.1
1967	7.6	0.6	0.0	-23.0	-18.4	0.0	-4.5	-25.4
1968	599.6	1.8	0.0	-606.7	-85.5	0.0	-521.2	-93.9
1969	5.0	0.9	0.0	-23.2	-83.0	0.0	59.8	-88.7
1970	8.0	1.2	0.0	-8.3	-74.1	0.0	65.8	-89.9
1971	6.4	0.9	0.0	-6.5	-74.8	0.0	68.4	-91.0
1972	3.2	1.3	0.0	11.0	2.7	0.0	8.3	-6.3
1973	1544.1	1.3	0.0	-1567.6	-197.7	0.0	-1369.9	-191.7
1974	1532.0	2.2	0.0	-1666.5	-428.6	0.0	-1237.9	-366.1
1975	359.6	2.5	0.0	-574.8	-511.2	0.0	-63.5	-427.6
1976	83.6	4.2	0.0	-505.5	-610.5	0.0	105.0	-452.9
1977	405.7	10.4	0.0	-790.4	-468.5	0.0	-321.9	-341.0
1978	649.7	9.1	0.0	-1057.5	-371.1	0.0	-686.4	-181.8
1979	686.4	15.7	0.0	-557.1	-151.9	0.0	-405.2	-23.3
1980	1467.7	19.2	0.0	-1215.1	-251.6	0.0	-963.6	47.7
1981	2705.5	22.3	0.0	-2192.8	-396.5	0.0	-1796.4	12.9
1982	658.6	26.4	0.0	258.5	-228.8	0.0	487.3	137.4

SOURCE: OUTPUT FILE HISTOIL TXOFFSHR BASECASE

TABLE E.6.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
COOK INLET PRICE DEREGULATION
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<u>CUMULATIVE, 1963-1971</u>	1730.7	561.6	261.1	112.4	69.1	119.0	143.1	0.116
1972.....	253.9	198.8	50.3	4.0	69.1	75.4	63.4	0.119
1973.....	281.3	214.2	51.8	27.1	74.1	61.2	91.4	0.122
1974.....	785.1	712.6	164.6	2.3	259.0	286.7	293.5	0.133
1975.....	829.8	741.2	163.3	1.2	273.5	303.2	312.5	0.140
1976.....	834.9	739.1	169.3	1.0	269.6	299.2	301.8	0.144
1977.....	839.7	755.9	172.6	0.7	278.8	303.9	292.5	0.146
1978.....	792.7	689.2	131.1	0.6	280.6	277.0	274.0	0.147
1979.....	916.6	807.1	143.3	0.5	337.7	325.6	318.7	0.148
1980.....	1197.4	1087.6	558.1	1.7	265.3	262.6	256.4	0.147
1981.....	1062.0	924.7	594.6	7.5	156.2	166.4	167.3	0.145
1982.....	885.0	723.4	467.4	4.6	113.8	137.5	146.6	0.144
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	30242.3	20551.0	6600.7	871.9	6225.1	6853.4	7096.3	0.144
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		20730.8		1392.4		6512.7		

SOURCE: OUTPUT FILE HISTOIL COOK DEREG

TABLE E.7.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
COOK INLET 1971 PRICE FREEZE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<u>CUMULATIVE, 1963-1971</u>	1730.7	561.6	261.1	112.4	69.1	119.0	143.1	0.116
1972.....	264.5	209.3	52.4	4.0	73.2	79.8	67.7	0.119
1973.....	277.8	210.6	51.1	27.1	72.8	59.7	89.9	0.122
1974.....	296.2	223.6	61.3	2.3	73.8	86.2	92.9	0.124
1975.....	344.9	256.3	66.2	1.2	87.4	101.5	110.8	0.125
1976.....	347.7	251.9	68.7	1.0	84.1	98.1	100.8	0.125
1977.....	327.1	243.3	67.1	0.7	83.4	92.2	80.8	0.125
1978.....	336.4	232.9	55.6	0.6	88.5	88.3	85.3	0.124
1979.....	348.1	238.6	53.0	0.5	93.4	91.6	84.7	0.123
1980.....	305.7	195.9	43.9	1.7	74.7	75.7	69.5	0.123
1981.....	314.2	176.8	51.1	7.5	58.3	59.9	60.8	0.12
1982.....	305.1	143.5	47.4	4.6	41.3	50.1	59.2	0.12
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	19694.6	10003.3	3290.7	871.9	2698.6	3142.0	3384.9	0.121
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		10183.0		1392.4		2801.4		

SOURCE: OUTPUT FILE HISTOIL COOK FREEZ71

TABLE E.8.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
COOK INLET 1976 PRICE FREEZE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<u>CUMULATIVE, 1963-1971</u>	1730.7	561.6	261.1	112.4	69.1	119.0	143.1	0.116
1972.....	253.9	198.8	50.3	4.0	69.1	75.4	63.4	0.119
1973.....	281.3	214.2	51.8	27.1	74.1	61.2	91.4	0.122
1974.....	369.3	296.7	76.8	2.3	101.5	116.2	122.9	0.125
1975.....	412.9	324.3	79.8	1.2	113.5	129.8	139.1	0.127
1976.....	383.5	287.7	76.1	1.0	97.7	112.9	115.6	0.127
1977.....	360.9	277.1	74.0	0.7	96.2	106.1	94.8	0.127
1978.....	368.8	265.3	61.0	0.6	102.2	101.7	98.7	0.126
1979.....	378.2	268.6	57.8	0.5	106.4	103.9	97.1	0.126
1980.....	333.3	223.6	54.3	1.7	83.4	84.2	78.0	0.125
1981.....	340.7	203.4	63.4	7.5	65.1	67.4	68.3	0.124
1982.....	329.7	168.1	58.8	4.6	47.3	57.3	66.4	0.123
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	20543.7	10852.5	3481.7	871.9	3017.5	3481.4	3724.2	0.123
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		11032.2		1392.4		3140.7		

SOURCE: OUTPUT FILE HISTOIL COOK FREEZ76

TABLE E.9.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
NORTH SLOPE 1976 PRICE FREEZE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND 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.....	2009.0	1079.6	490.3	1.1	88.2	500.0	195.9	-
1979.....	2564.7	1617.0	612.8	568.4	237.1	198.6	349.6	-
1980.....	3331.1	2140.1	765.2	15.2	523.4	836.4	732.7	-
1981.....	3646.9	1269.6	842.6	3.3	324.1	99.5	907.8	-
1982.....	4110.2	919.7	1037.8	116.9	85.9	-321.0	818.4	-
 <u>CUMULATIVE DISCOUNTED CASH FLOW, 1964-82 (IN 1982 DOLLARS)</u>	 23056.8	 -9919.6	 5450.5	 8809.1	 -9678.4	 -14500.8	 -4871.5	 -
 <u>CUMULATIVE, 1964-1982 WITH PARTIAL CAPITAL RECOVERY</u>		 14706.8		 3162.4		 15772.3		

^a"-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL NSLOPE FREEZ76

TABLE E.10.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS OFFSHORE 1971 PRICE FREEZE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND 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.....	55.6	26.3	11.8	3.2	2.8	8.5	-6.2	-
1973.....	56.8	-12.3	11.6	1544.1	-197.9	-1370.2	-192.0	-
1974.....	74.5	-122.9	15.9	1532.0	-430.7	-1240.2	-368.3	-
1975.....	92.7	-190.5	28.1	359.6	-512.9	-65.3	-429.4	-
1976.....	118.7	-389.4	38.5	83.6	-613.4	101.8	-456.1	-
1977.....	235.4	-335.9	58.4	405.7	-473.2	-326.9	-346.0	-
1978.....	480.5	-303.4	119.3	649.7	-378.2	-694.1	-189.4	-
1979.....	1183.1	323.7	224.3	686.4	-165.7	-421.4	-39.5	-
1980.....	1771.1	520.9	396.3	1467.7	-310.4	-1032.7	-21.4	-
1981.....	2355.9	697.3	500.5	2705.5	-541.7	-1966.9	-157.6	-
1982.....	2965.4	1157.2	625.6	658.6	-406.1	279.1	-70.8	-
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	15547.7	-2639.3	3336.3	30797.6	-13781.2	-22992.1	-11191.0	-
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		6205.4		9456.1		7194.1		

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

SOURCE: OUTPUT FILE HISTOIL TXOFFSHR FREEZ71

TABLE E.11.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS OFFSHORE 1976 PRICE FREEZE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND 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.....	251.6	-319.7	61.9	405.7	-467.1	-320.3	-339.4	-
1978.....	503.1	-280.9	125.0	649.7	-370.1	-685.4	-180.7	-
1979.....	1216.0	356.6	230.5	686.4	-153.4	-406.9	-25.0	-
1980.....	1844.0	593.8	409.7	1467.7	-283.0	-1000.5	10.8	-
1981.....	2458.9	800.4	518.2	2705.5	-502.5	-1920.8	-111.5	-
1982.....	3094.4	1286.3	647.6	658.6	-356.9	336.9	-13.0	-
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	16094.5	-2092.5	3438.2	30797.6	-13574.4	-22754.1	-10953.0	-
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		6752.2		9456.1		7432.2		

^a- " INDICATES RETURN OF LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL TXOFFSHR FREEZ76

TABLE E.12.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS ONSHORE PRICE DEREGULATION
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<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.....	16072.5	11942.4	857.9	32.5	5854.3	5197.8	4764.7	0.145
1975.....	17351.7	12077.1	1048.2	23.6	5877.6	5127.7	5121.7	0.148
1976.....	20431.9	14570.9	1314.8	31.4	7007.9	6216.8	5897.3	0.149
1977.....	22923.5	16098.5	1517.9	37.7	7680.8	6862.0	6580.7	0.150
1978.....	22083.9	13813.1	1457.2	48.1	6542.1	5765.7	5848.6	0.148
1979.....	27405.9	18356.8	1792.1	33.4	8349.8	8181.5	7704.2	0.147
1980.....	39889.3	27477.1	8016.4	41.8	4778.7	14640.4	15293.6	0.148
1981.....	43532.1	25052.6	10485.1	169.8	3640.3	10757.4	14772.1	0.147
1982.....	39901.7	20405.8	7955.0	69.4	2928.4	9453.0	11724.8	0.144
 CUMULATIVE DISCOUNTED CASH FLOW, 1962-82 (IN 1982 DOLLARS)	1028315.0	488868.5	83407.9	2154.4	193565.4	209740.5	195958.1	0.144
 CUMULATIVE, 1962-1982 WITH PARTIAL CAPITAL RECOVERY		546575.6		1717.9		267884.7		

SOURCE: OUTPUT FILE HISTOIL TXONSHR Dereg

TABLE E.13.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS ONSHORE 1971 PRICE FREEZE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<u>CUMULATIVE, 1962-1971</u>	81143.6	23930.2	4635.2	197.3	9576.8	9520.8	6886.7	0.141
1972.....	6084.1	2973.6	346.0	5.4	1364.8	1257.3	1085.9	0.140
1973.....	6556.2	3241.7	372.5	12.0	1496.7	1360.6	1226.3	0.139
1974.....	7708.1	3578.1	454.1	32.5	1687.4	1404.1	1636.1	0.137
1975.....	9262.1	3987.5	630.5	23.6	1860.5	1472.8	2110.1	0.136
1976.....	10684.7	4823.8	764.6	31.4	2191.5	1836.2	2289.5	0.134
1977.....	11920.6	5095.6	891.9	37.7	2246.3	1919.8	2510.9	0.133
1978.....	11917.7	3646.8	877.6	48.1	1521.2	1200.0	2089.3	0.130
1979.....	13647.9	4598.9	1025.2	33.4	1784.1	1756.2	2371.2	0.129
1980.....	15798.2	3386.0	1182.3	41.8	588.9	1573.1	3680.6	0.127
1981.....	17441.6	-1037.9	1307.0	169.8	-673.6	-1841.1	3601.2	0.125
1982.....	17938.1	-1557.7	1293.3	69.4	-1242.9	-1677.6	1885.8	0.12
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1962-82 (IN 1982 DOLLARS)</u>	786626.9	247179.9	48058.9	2154.4	101859.9	95106.5	98666.1	0.122
<u>CUMULATIVE, 1962-1982 WITH PARTIAL CAPITAL RECOVERY</u>		304886.5		1717.9		153250.4		

SOURCE: OUTPUT FILE HISTOIL TXONSHR FREEZ71

TABLE E.14.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS ONSHORE 1976 PRICE FREEZE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<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.....	14676.8	8815.9	972.9	31.4	4172.8	3638.7	3774.5	0.141
1977.....	15958.1	9133.2	1104.4	37.7	4249.2	3741.8	4011.8	0.140
1978.....	16004.3	7733.5	1096.6	48.1	3546.7	3042.2	3606.5	0.138
1979.....	17848.8	8799.8	1249.9	33.4	3793.5	3722.9	4003.8	0.136
1980.....	20171.6	7759.4	1415.9	41.8	1543.4	4758.3	6518.0	0.135
1981.....	22046.2	3566.7	1555.1	169.8	739.8	1102.0	6178.0	0.132
1982.....	22700.1	3204.3	1553.2	69.4	433.6	1148.0	4332.6	0.130
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1962-82 (IN 1982 DOLLARS)</u>	865131.3	325683.8	52147.8	2154.4	137305.9	134075.7	131392.2	0.130
<u>CUMULATIVE, 1962-1982 WITH PARTIAL CAPITAL RECOVERY</u>		383391.2		1717.9		192219.9		

SOURCE: OUTPUT FILE HISTOIL TXONSHR FREEZ76

TABLE E.15.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
COOK INLET WITH TEXAS MARKET PARAMETERS
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVE'S TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<u>CUMULATIVE, 1963-1971</u>	1778.7	1416.6	271.4	112.4	476.6	556.3	511.9	0.240
1972.....	274.3	265.3	54.3	4.0	99.8	107.2	107.1	0.245
1973.....	321.0	309.4	59.0	27.1	116.2	107.2	127.8	0.243
1974.....	526.7	508.4	108.9	2.3	187.6	209.6	209.4	0.251
1975.....	624.3	606.9	120.2	1.2	229.6	256.0	251.2	0.257
1976.....	635.7	611.8	125.6	1.0	229.7	255.5	254.1	0.259
1977.....	616.7	598.1	126.3	0.7	226.0	245.2	243.1	0.259
1978.....	629.0	606.4	101.3	0.6	254.5	250.1	250.9	0.257
1979.....	741.0	716.5	113.6	0.5	307.6	294.8	295.8	0.255
1980.....	1035.3	1003.6	274.3	1.7	368.9	358.8	365.9	0.254
1981.....	1415.9	1388.3	585.2	7.5	384.6	411.0	415.8	0.252
1982.....	1271.5	1238.5	451.0	4.6	357.0	425.8	429.3	0.250
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	28038.5	25277.8	5598.9	871.9	8988.6	9818.3	9637.9	0.249
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		25182.1		1392.4		9202.3		

SOURCE: OUTPUT FILE HISTOIL COOK ECONTEXT

TABLE E.16.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
NORTH SLOPE WITH COOK INLET MARKET PARAMETERS
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND 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	-1570.7	0.0	1247.6	-994.4	-1823.9	-784.5	-
1972.....	0.0	-116.0	0.0	1.5	-208.0	90.5	-315.5	-
1973.....	0.0	-148.8	0.0	1.7	-126.1	-24.4	-149.3	-
1974.....	0.0	-356.9	0.0	1.8	-156.9	-201.9	-49.5	-
1975.....	0.0	-920.6	0.0	1.7	-338.3	-583.9	-60.0	-
1976.....	0.0	-1263.2	0.0	1.4	-421.2	-843.3	-276.0	-
1977.....	593.7	-515.1	121.0	1.3	-282.3	-355.1	-212.4	-
1978.....	2228.5	1445.6	514.8	1.1	257.3	672.5	304.5	-
1979.....	2832.6	1885.2	644.1	568.4	356.9	315.7	440.9	-
1980.....	5596.6	4331.0	2070.7	15.2	965.6	1279.5	1104.4	-
1981.....	16730.9	13995.3	10642.3	3.3	1719.9	1629.8	2297.9	-
1982.....	16447.4	12572.7	9987.1	116.9	1309.6	1159.0	2150.4	-
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1964-82 (IN 1982 DOLLARS)</u>	54492.6	21047.7	27717.5	8809.1	-5549.0	-9929.8	-1118.3	-
<u>CUMULATIVE, 1964-1982 WITH PARTIAL CAPITAL RECOVERY</u>		43997.1		3162.4		18666.2		

a "-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL NSLOPE ECONCI

TABLE E.17.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
NORTH SLOPE WITH TEXAS MARKET PARAMETERS
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND 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	-1360.4	0.0	1247.6	-897.6	-1710.5	-771.2	-
1972.....	0.0	-92.5	0.0	1.5	-195.5	101.5	-281.5	-
1973.....	0.0	-130.5	0.0	1.7	-116.3	-15.9	-121.6	-
1974.....	0.0	-325.6	0.0	1.8	-141.7	-185.8	-34.3	-
1975.....	0.0	-840.7	0.0	1.7	-301.2	-541.2	-58.6	-
1976.....	0.0	-1188.7	0.0	1.4	-385.9	-804.2	-260.0	-
1977.....	956.1	-57.5	194.7	1.3	-97.5	-156.1	-14.0	-
1978.....	3693.3	3168.0	789.3	1.1	987.0	1390.7	999.3	-
1979.....	5882.9	5390.0	1290.6	568.4	1815.0	1716.0	1809.5	-
1980.....	12187.8	11621.1	4478.5	15.2	3432.1	3695.4	3462.5	0.104
1981.....	19231.9	17678.6	10170.2	3.3	3707.9	3797.1	4389.7	0.104
1982.....	18728.0	16503.9	9216.6	116.9	3448.8	3721.6	4627.2	0.104
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1964-82 (IN 1982 DOLLARS)</u>	77892.9	52055.9	31593.0	8809.1	7720.5	3933.2	11781.9	0.118
<u>CUMULATIVE, 1964-1982 WITH PARTIAL CAPITAL RECOVERY</u>		72125.6		3162.4		29649.6		

^a- " INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL NSLOPE ECONTEX

TABLE E.18.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS OFFSHORE WITH COOK INLET MARKET PARAMETERS
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN ^a
<u>CUMULATIVE, 1963-1971</u>	557.2	-379.9	105.1	1149.6	-699.0	-935.6	-713.4	-
1972.....	48.7	15.1	10.4	3.2	-2.6	4.1	-24.1	-
1973.....	45.7	-72.5	9.3	1544.1	-224.8	-1401.1	-197.0	-
1974.....	55.5	-245.5	11.7	1532.0	-485.3	-1303.9	-370.5	-
1975.....	75.6	-289.5	22.6	359.6	-557.6	-114.2	-454.1	-
1976.....	89.0	-419.1	28.6	83.6	-625.7	94.3	-519.2	-
1977.....	124.0	-382.3	30.5	405.7	-485.8	-332.7	-439.5	-
1978.....	223.1	-462.8	55.4	649.7	-426.6	-741.3	-304.6	-
1979.....	510.6	-85.4	96.8	686.4	-299.6	-569.0	-331.8	-
1980.....	603.6	-198.8	131.0	1467.7	-525.4	-1272.2	-477.1	-
1981.....	1055.2	65.0	205.6	2705.5	-704.3	-2141.8	-528.5	-
1982.....	1181.7	199.7	229.2	658.6	-668.9	-19.2	-642.2	-
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	9465.6	-7612.7	1941.9	30797.6	-15486.0	-24866.3	-14008.5	-
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		-565.0		9456.1		3523.1		

^a "-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL TXOFFSHR ECONCI

TABLE E.19.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS OFFSHORE WITH TEXAS ONSHORE MARKET PARAMETERS
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN ^a
<u>CUMULATIVE, 1963-1971</u>	359.0	-213.1	67.0	1149.6	-603.5	-826.2	-696.4	-
1972.....	54.0	39.3	11.5	3.2	9.7	14.9	9.4	-
1973.....	57.9	24.4	11.9	1544.1	-180.8	-1350.8	-184.5	-
1974.....	97.2	1.1	20.7	1532.0	-375.5	-1176.1	-360.2	-
1975.....	125.6	44.4	37.8	359.6	-408.3	55.3	-420.7	-
1976.....	161.5	5.7	52.1	83.6	-435.3	305.3	-428.3	-
1977.....	273.2	98.9	67.5	405.7	-271.1	-103.2	-247.1	-
1978.....	440.4	199.7	109.4	649.7	-134.4	-425.0	-76.2	-
1979.....	931.0	671.3	176.4	686.4	16.8	-208.3	67.7	-
1980.....	1591.4	1228.7	387.3	1467.7	12.7	-639.1	121.6	-
1981.....	2284.3	1791.6	509.7	2705.5	-47.4	-1376.2	97.0	-
1982.....	2908.7	2428.1	684.9	658.6	139.2	945.3	296.8	-
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	14901.9	7186.4	3375.1	30797.6	-9239.2	-17747.2	-9051.5	-
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		9516.7		9456.1		5924.7		

^a"-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL TXOFFSHR ECONTEXT

TABLE E.20.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
COOK INLET WITH FEDERAL OCS TAX STRUCTURE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<u>CUMULATIVE, 1963-1971</u>	1730.7	561.6	231.7	112.4	83.1	134.4	158.4	0.117
1972.....	253.9	198.8	39.7	4.0	74.2	80.9	68.8	0.121
1973.....	281.3	214.2	43.1	27.1	78.3	65.7	95.9	0.124
1974.....	369.3	296.7	57.0	2.3	111.0	126.4	133.2	0.127
1975.....	412.9	324.3	57.5	1.2	124.2	141.5	150.8	0.129
1976.....	383.5	287.7	57.0	1.0	106.9	122.9	125.5	0.130
1977.....	357.0	273.3	52.7	0.7	104.6	115.2	103.9	0.129
1978.....	362.3	258.8	49.7	0.6	99.5	109.0	106.0	0.129
1979.....	371.3	261.7	49.0	0.5	96.9	115.3	108.4	0.128
1980.....	452.3	342.5	112.2	1.7	93.3	135.3	129.1	0.127
1981.....	1062.0	924.7	429.4	7.5	209.0	278.8	279.7	0.128
1982.....	885.0	723.4	279.6	4.6	192.3	246.8	255.9	0.128
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	22073.6	12382.3	3644.8	871.9	3571.7	4294.0	4536.8	0.128
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		12562.1		1392.4		3953.3		

SOURCE: OUTPUT FILE HISTOIL COOK TAXOCS

TABLE E.21.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
COOK INLET WITH TEXAS STATE TAX STRUCTURE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<u>CUMULATIVE, 1963-1971</u>	1730.7	561.6	281.2	112.4	76.9	91.1	81.7	0.109
1972.....	253.9	198.8	47.1	4.0	78.1	69.6	43.2	0.111
1973.....	281.3	214.2	51.3	27.1	83.3	52.5	65.6	0.114
1974.....	369.3	296.7	67.4	2.3	118.4	108.7	91.6	0.116
1975.....	412.9	324.3	70.6	1.2	131.5	121.0	104.1	0.118
1976.....	383.5	287.7	67.1	1.0	113.8	105.8	85.8	0.119
1977.....	357.0	273.3	57.4	0.7	113.0	102.2	70.4	0.119
1978.....	362.3	258.8	59.8	0.6	105.0	93.4	70.6	0.118
1979.....	371.3	261.7	61.2	0.5	102.0	98.1	71.6	0.118
1980.....	452.3	342.5	105.3	1.7	60.3	175.2	145.7	0.118
1981.....	1062.0	924.7	436.3	7.5	123.0	357.9	307.8	0.117
1982.....	885.0	723.4	324.6	4.6	108.8	285.3	251.5	0.117
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	22073.6	12382.3	4231.8	871.9	3457.9	3820.7	3206.1	0.120
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		12562.1		1392.4		3480.0		

SOURCE: OUTPUT FILE HISTOIL COOK TAXTEX

TABLE E.22.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
NORTH SLOPE WITH FEDERAL OCS TAX STRUCTURE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND 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	98.7	1.3	-303.7	-391.1	-189.7	-
1978.....	2008.8	1079.4	261.2	1.1	191.1	626.0	321.9	-
1979.....	4909.5	3961.8	667.7	568.4	1260.7	1465.0	1615.9	-
1980.....	9314.2	8123.1	1914.9	15.2	2463.8	3729.2	3625.6	-
1981.....	12916.6	10539.3	3388.8	3.3	3184.5	3962.7	4771.0	0.108
1982.....	11666.5	8476.0	2020.1	116.9	2987.7	3351.2	4490.6	0.113
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1964-82 (IN 1982 DOLLARS)</u>	53773.7	20797.4	10546.5	8809.1	1263.9	177.9	9807.2	0.113
<u>CUMULATIVE, 1964-1982 WITH PARTIAL CAPITAL RECOVERY</u>		45423.7		3162.4		30450.9		

^a- " INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL NSLOPE TAXOCS

TABLE E.23.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
NORTH SLOPE WITH TEXAS STATE TAX STRUCTURE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND 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	-1060.2	-1734.3	-561.8	-
1972.....	0.0	-111.0	0.0	1.5	-227.9	115.4	-245.7	-
1973.....	0.0	-144.7	0.0	1.7	-135.6	-10.7	-110.7	-
1974.....	0.0	-360.2	0.0	1.8	-166.8	-195.2	-17.9	-
1975.....	0.0	-942.1	0.0	1.7	-365.5	-578.3	-3.2	-
1976.....	0.0	-1317.8	0.0	1.4	-477.3	-841.9	-179.0	-
1977.....	693.4	-584.8	107.4	1.3	-326.2	-367.3	-140.6	-
1978.....	2008.8	1079.4	307.3	1.1	199.0	572.0	210.3	-
1979.....	4909.5	3961.8	783.9	568.4	1357.7	1251.7	1124.0	-
1980.....	9314.2	8123.1	1929.0	15.2	1776.9	4402.0	3699.0	0.102
1981.....	12916.6	10539.3	3699.6	3.3	2113.0	4723.4	4763.5	0.11
1982.....	11666.5	8476.0	2495.4	116.9	2014.4	3849.3	4286.2	0.115
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1964-82 (IN 1982 DOLLARS)</u>	53773.7	20797.4	11713.3	8809.1	-2617.4	2892.3	11158.5	0.115
<u>CUMULATIVE, 1964-1982 WITH PARTIAL CAPITAL RECOVERY</u>		45423.7		3162.4		33165.4		

^a "-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL NSLOPE TAXTEX

TABLE E.24.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS OFFSHORE WITH ALASKA STATE TAX STRUCTURE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND 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	69.2	1149.6	-688.7	-920.0	-756.5	-
1972.....	55.3	26.0	12.5	3.2	2.4	8.0	-6.6	-
1973.....	57.4	-11.7	12.4	1544.1	-198.0	-1370.3	-192.1	-
1974.....	79.6	-117.7	17.6	1532.0	-429.0	-1238.4	-366.5	-
1975.....	97.0	-186.3	29.7	359.6	-511.6	-63.9	-428.0	-
1976.....	126.4	-381.8	42.4	83.6	-611.6	103.8	-454.1	-
1977.....	247.8	-323.6	70.4	405.7	-473.0	-326.7	-345.8	-
1978.....	500.4	-283.6	134.2	649.7	-375.9	-691.6	-186.9	-
1979.....	1219.8	360.5	266.6	686.4	-168.2	-424.3	-42.4	-
1980.....	1927.8	677.6	476.1	1467.7	-275.0	-991.1	20.2	-
1981.....	2737.1	1078.6	633.3	2705.5	-427.5	-1832.8	-23.5	-
1982.....	3430.1	1621.9	784.0	658.6	-260.2	444.5	94.6	-
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	16864.2	-1322.8	3907.9	30797.6	-13437.4	-22591.1	-10790.0	-
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		7521.8		9456.1		7595.2		

^a"-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL TXOFFSHR TAXCI

TABLE E.25.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS OFFSHORE WITH TEXAS STATE TAX STRUCTURE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND 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	81.7	1149.6	-754.8	-866.4	-586.5	-
1972.....	55.3	26.0	13.6	3.2	2.0	7.2	-7.9	-
1973.....	57.4	-11.7	13.7	1544.1	-215.1	-1354.5	-144.5	-
1974.....	79.6	-117.7	19.1	1532.0	-463.6	-1205.2	-268.2	-
1975.....	97.0	-186.3	31.4	359.6	-552.1	-25.2	-313.0	-
1976.....	126.4	-381.8	42.4	83.6	-636.2	148.4	-323.7	-
1977.....	247.8	-323.6	64.7	405.7	-503.3	-290.7	-246.3	-
1978.....	500.4	-283.6	143.1	649.7	-399.9	-676.4	-133.7	-
1979.....	1219.8	360.5	289.0	686.4	-179.3	-435.6	-52.3	-
1980.....	1927.8	677.6	514.3	1467.7	-287.5	-1016.8	-15.0	-
1981.....	2737.1	1078.6	696.0	2705.5	-455.0	-1868.0	-61.2	-
1982.....	3430.1	1621.9	869.9	658.6	-285.8	379.1	-6.0	-
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	16864.2	-1322.8	4263.2	30797.6	-14521.0	-21861.7	-13289.6	-
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		7521.8		9456.1		8323.5		

a "-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL TXOFFSHR TAXTEX

TABLE E.26.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS ONSHORE WITH ALASKA STATE TAX STRUCTURE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<u>CUMULATIVE, 1962-1971</u>	81143.6	23930.2	2048.9	197.3	10055.9	11628.1	10524.7	0.163
1972.....	5895.8	2785.2	373.8	5.4	1144.0	1261.9	1315.7	0.159
1973.....	6881.8	3567.3	358.2	12.0	1530.0	1667.1	1782.6	0.157
1974.....	11137.0	7007.0	828.3	32.5	2995.2	3151.0	3687.7	0.159
1975.....	13180.2	7905.6	1025.6	23.6	3359.1	3497.3	4504.9	0.158
1976.....	14676.7	8815.8	1275.0	31.4	3644.5	3864.9	4737.8	0.157
1977.....	15760.5	8935.5	1770.7	37.7	3434.4	3692.7	4732.1	0.155
1978.....	15988.3	7717.5	674.9	48.1	3394.1	3600.4	4832.7	0.152
1979.....	20378.6	11329.5	841.4	33.4	4751.6	5703.1	6712.8	0.150
1980.....	30696.2	18284.0	5006.6	41.8	6107.8	7127.9	9640.8	0.149
1981.....	42942.8	24463.3	13560.4	169.8	5187.7	5545.4	11272.1	0.146
1982.....	39785.2	20289.4	10706.7	69.4	4370.1	5143.2	8778.9	0.143
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1962-82 (IN '82 DOLLARS)</u>	925123.0	385675.6	66806.6	2154.4	149436.4	167277.6	189527.5	0.143
<u>CUMULATIVE, 1962-1982 WITH PARTIAL CAPITAL RECOVERY</u>		443382.9		1717.9		225421.8		

SOURCE: OUTPUT FILE HISTOIL TXONSHR TAXCI

TABLE E.27.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS ONSHORE WITH FEDERAL OCS TAX STRUCTURE
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<u>CUMULATIVE, 1962-1971</u>	81143.6	23930.2	2996.5	197.3	9575.6	11160.9	10057.5	0.160
1972.....	5895.8	2785.2	131.5	5.4	1260.4	1387.9	1441.7	0.158
1973.....	6881.8	3567.3	143.1	12.0	1633.3	1779.0	1894.4	0.156
1974.....	11137.0	7007.0	250.9	32.5	3272.3	3451.2	3987.9	0.158
1975.....	13180.2	7905.6	358.4	23.6	3679.3	3844.3	4851.8	0.159
1976.....	14676.7	8815.8	554.8	31.4	3990.2	4239.4	5112.4	0.158
1977.....	15760.5	8935.5	845.7	37.7	3878.4	4173.6	5213.1	0.156
1978.....	15988.3	7717.5	538.2	48.1	3459.7	3671.5	4903.8	0.153
1979.....	20378.6	11329.5	600.4	33.4	4862.5	5833.3	6842.9	0.151
1980.....	30696.2	18284.0	4277.1	41.8	5788.3	8176.9	10689.7	0.150
1981.....	42942.8	24463.3	9261.8	169.8	6585.4	8446.3	14173.0	0.149
1982.....	39785.2	20289.4	5790.1	69.4	6269.5	8160.4	11796.1	0.145
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1962-82 (IN 1982 DOLLARS)</u>	925123.0	385675.6	50146.2	2154.4	155091.9	178283.0	200532.5	0.145
<u>CUMULATIVE, 1962-1982 WITH PARTIAL CAPITAL RECOVERY</u>		443382.9		1717.9		236427.0		

SOURCE: OUTPUT FILE HISTOIL TXONSHR TAXOCS

TABLE E.28.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
COOK INLET WITH TEXAS TAX AND MARKET PARAMETERS
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN
<u>CUMULATIVE, 1963-1971</u>	1778.7	1416.6	291.7	112.4	518.0	494.5	351.4	0.196
1972.....	274.3	265.3	50.8	4.0	112.3	98.1	77.2	0.200
1973.....	321.0	309.4	58.5	27.1	128.9	94.9	91.4	0.199
1974.....	526.7	508.4	96.0	2.3	214.7	195.4	154.8	0.206
1975.....	624.3	606.9	106.7	1.2	260.9	238.1	185.6	0.211
1976.....	635.7	611.8	111.0	1.0	261.9	237.9	188.1	0.213
1977.....	616.7	598.1	99.9	0.7	263.2	234.4	185.1	0.214
1978.....	629.0	606.4	103.7	0.6	266.0	236.2	189.0	0.213
1979.....	741.0	716.5	122.2	0.5	303.7	290.0	234.3	0.212
1980.....	1035.3	1003.6	250.0	1.7	248.4	503.5	437.8	0.215
1981.....	1415.9	1388.3	488.7	7.5	291.2	600.9	515.6	0.218
1982.....	1271.5	1238.5	381.7	4.6	300.7	551.5	469.5	0.218
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	28038.5	25277.8	5311.1	871.9	9434.0	9660.8	7609.6	0.218
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		25182.1		1392.4		9044.7		

SOURCE: OUTPUT FILE HISTOIL COOK COMB.TEX

TABLE E.29.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
NORTH SLOPE WITH TEXAS TAX AND MARKET PARAMETERS
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND 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	-1360.4	0.0	1247.6	-969.8	-1638.3	-559.9	-
1972.....	0.0	-92.5	0.0	1.5	-216.1	122.1	-221.1	-
1973.....	0.0	-130.5	0.0	1.7	-126.6	-5.6	-91.5	-
1974.....	0.0	-325.6	0.0	1.8	-149.3	-178.1	-12.0	-
1975.....	0.0	-840.7	0.0	1.7	-316.8	-525.7	-13.0	-
1976.....	0.0	-1188.7	0.0	1.4	-413.9	-776.2	-178.2	-
1977.....	956.1	-57.5	148.1	1.3	-73.3	-133.8	4.6	-
1978.....	3693.3	3168.0	565.0	1.1	1159.8	1442.2	832.2	-
1979.....	5882.9	5390.0	939.2	568.4	2003.0	1879.3	1583.2	-
1980.....	12187.8	11621.1	3241.4	15.2	2509.0	5855.6	4823.2	0.111
1981.....	19231.9	17678.6	7233.0	3.3	3196.9	7245.3	6723.1	0.111
1982.....	18728.0	16503.9	6231.1	116.9	3444.1	6711.8	6504.9	0.111
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1964-82 (IN 1982 DOLLARS)</u>	77892.9	52055.9	22290.4	8809.1	5787.8	15168.6	19838.2	0.130
<u>CUMULATIVE, 1964-1982 WITH PARTIAL CAPITAL RECOVERY</u>		72125.6		3162.4		40885.0		

^a"-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL NSLOPE COMB.TEX

TABLE E.30.
DISTRIBUTION OF ECONOMIC RENT FROM OIL AND GAS PRODUCTION
TEXAS OFFSHORE WITH TEXAS STATE TAX AND MARKET PARAMETERS
(MILLIONS OF CURRENT DOLLARS)

	TOTAL OIL AND GAS REVENUE	TOTAL ECONOMIC RENT	ROYALTIES AND EXCISE TAXES	LEASE BONUS AND RENTAL PAYMENTS	INCOME AND RESERVES TAXES	AFTER-TAX PRODUCERS' ECONOMIC RENT	AFTER-TAX PRODUCERS' PROFITS	CUMULATIVE AFTER-TAX RATE OF RETURN ^a
<u>CUMULATIVE, 1963-1971</u>	359.0	-213.1	77.9	1149.6	-662.6	-778.0	-543.7	-
1972.....	54.0	39.3	13.3	3.2	10.0	12.8	5.0	-
1973.....	57.9	24.4	13.9	1544.1	-197.2	-1336.4	-140.3	-
1974.....	97.2	1.1	23.6	1532.0	-408.1	-1146.4	-270.4	-
1975.....	125.6	44.4	41.1	359.6	-444.4	88.1	-321.3	-
1976.....	161.5	5.7	54.9	83.6	-472.2	339.4	-325.9	-
1977.....	273.2	98.9	71.5	405.7	-293.2	-85.1	-190.1	-
1978.....	440.4	199.7	125.9	649.7	-147.8	-428.1	-68.8	-
1979.....	931.0	671.3	220.0	686.4	6.0	-241.1	17.8	-
1980.....	1591.4	1228.7	442.6	1467.7	8.7	-690.4	36.3	-
1981.....	2284.3	1791.6	572.6	2705.5	-56.7	-1429.7	7.2	-
1982.....	2908.7	2428.1	828.9	658.6	82.8	857.8	138.7	-
<u>CUMULATIVE DISCOUNTED CASH FLOW, 1963-82 (IN 1982 DOLLARS)</u>	14901.9	7186.4	3901.6	30797.6	-10191.2	-17321.7	-7301.2	-
<u>CUMULATIVE, 1963-1982 WITH PARTIAL CAPITAL RECOVERY</u>		9516.7		9456.1		6350.1		

^a"-" INDICATES RETURN LESS THAN 10 PERCENT

SOURCE: OUTPUT FILE HISTOIL TXOFFSHR COMB.TEX

APPENDIX F
FINDOIL MODEL DOCUMENTATION

FINDOIL is a model adapting the accounting conventions of the model HISTOIL to the analysis of future production from individual oil fields. The accounting structure of FINDOIL is virtually identical to that of HISTOIL, except that all cash flows are discounted to 1984 (in 1984 dollars), instead of to 1982. The only difference is the addition of two optional capital cost variables, representing fixed and variable field development costs. The model arbitrarily allocates cash flow capital spending over time from these two new variables, following the pattern discussed in for the North Slope region in Appendix C.

In addition to the two capital cost variables, FINDOIL differs from HISTOIL in that oil production is endogenously determined by three parameters specific to the individual field (these parameters are actually defined as "exogenous" variables in the model). These are the the initial recoverable reserves in the field, the peak production capacity, and the number of years production remains at the peak rate. Oil production reaches peak capacity during the second year of commercial production, and eventually declines at a rate determined by the ratio of production to reserves remaining in the field at the time production begins its decline. Production ends when operating costs exceed revenues or at the end of year 2010, whichever occurs first, and abandonment costs or salvage values are not considered.

Exact definitions for the new variables in FINDOIL are displayed below. Variables not explicitly included below are defined as described in Appendix D for the model HISTOIL. Table F.1 contains base case assumptions for the main exogenous variables for each proposed or ongoing field development activity. The field development assumptions are compiled from information obtained from

published industry sources,¹ the State of Alaska,² and from Arlon Tussing.³ Table F.2 through F.14 summarize the base case projection for each of the 13 North Slope field development activities considered in the study.

Variable Definitions

<u>Symbol</u>	<u>Type</u>	<u>Variable</u>	<u>Definition</u>
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Exogenous

CAPOIL			Peak production capacity, in thousands of barrels per day.
FIXED			Total cumulative fixed exploration and development costs in millions of dollars. ⁴
NOIL			Number of years production remains at peak level.
POILBASE			Initial price of oil (\$ 1984 per barrel).
RESERVTO			Initial technically recoverable reserves (at time to) in millions of barrels.
TO			Year production commences from the field.
VARIABLE			Total cumulative variable development costs per barrel of reserves. ⁴

Definition

GAMMA			Production decline rate after time to + NOIL.
RESERVES			Remaining technically recoverable reserves in million barrels.

Parameter

BETA			Annual rate of escalation of oil prices.
DEF1984			Value of GNP deflator in 1984.

ENDNOTES

¹Oil and Gas Journal, July 2, 1984, p. 27; Oil and Gas Journal, June 25, 1984, pp. 55-58; Oil and Gas Journal, June 25, 1984, pp. 63-65

²Alaska Oil and Gas Conservation Commission, Annual Statistical Report, 1983; and Historical and Projected Oil and Gas Consumption, January 1984, Alaska Department of Natural Resources, Division of Minerals and Energy Management, Appendix A.

³Arlon R. Tussing, personal communication, May 20, 1984.

⁴Model projected with DEFLATOR equal to DEF1984 for 1984 and for all later years, so that nominal values produced by the model are the same as real values in 1984.

MODEL LISTING: FINDOIL

SYMBOL DECLARATIONS

ENDOGENOUS:

CAAFTAX CUMQOIL F NPR OPAFTAX PDAFTAX PDAFTPRO PDBONUS PDCARENT PDEXCISE PDINCOME POOPRENT
PDREV PDSRPLUS PDVOP QOIL RESTAX RF TAXBASE TAXINCF TAXINCS

DEFINITION:

AFTPROF C CAINCOME CAPITAL CARENT CAVALUE CONSVTAX CORPRATE CORPTXF CORPTXS DEPALLOW DEVELOP
ELFCALC ELFGAS ELFOIL EXCISE EXCSHR EXROYOIL EXTAXOIL FRTIER1 GAMMA GASNOMRT GASROY GASSEVRT
GASSEVTX INTANG NETREV NETTXROY NPS OILNOMRT OILPCT OILROY OILSEVRT OILSEVTX OPINCOME OPRENT
OPVALUE PDVCASH POIL POILBAS1 POILBAS2 POILBAS3 PROPTAX RESERVES REV ROYALTY S SEVTAX SRPLUS
TAPSAJ T1981 WINDPROF WPTAX WPTAXRT WPTAX1 WPTBASEN WPTBASE1 WPTBASE2 WPTBASE3

EXOGENOUS:

BONUS CAPOIL CBBL CENTSBBL CENTSMCF CMCF CWGAS CWOIL DEFLATOR DEPALLRT DRILLING ELGASEXP
ELOILEXP EXPLINCR EXPLORE FCORPRT FIXED FOOTAGE FREXEMPT FRINDEPN FRTIERN FRTIER2 FRTIER3
GASPCT GASWELLS INEFFECT INVIXCR LOWOIL NOIL NPSRATE OILPCT1 OILWELLS PGAS PHASEOUT POILBASE
POIL79T1 POIL79T2 POIL79T3 QGAS RENTAL RESERVTO RGAS ROIL SCORPRT TARIFF TXOILROY TO VARIABLE
WPTRATEN YEAR

PARAMETER:

BETA CONSRATE DEF1979 DEF1984 DELTA DEPRATE PCTINTAN PELGAS PELOIL PROPRATE RESRATE WPTRATE1
WPTRATE2 WPTRATE3

EQUATIONS:

- 1: $GAMMA = CAPOIL * 365 / (RESERVTO - CAPOIL * 365 * NOIL)$
- 2: $POIL = POILBASE * (1 + BETA) ** (YEAR - 1984)$
- 3: $DEVELOP = IF\ YEAR\ LT\ TO-2\ THEN\ 0\ ELSE\ (IF\ YEAR\ EQ\ TO-2\ THEN\ 0.2 * FIXED + 0.1 * VARIABLE * RESERVTO$
 $ELSE\ (IF\ YEAR\ LE\ TO\ THEN\ 0.4 * FIXED + 0.2 * VARIABLE * RESERVTO\ ELSE\ (IF\ YEAR\ LE\ TO + NOIL\ THEN$
 $0.5 / NOIL * VARIABLE * RESERVTO\ ELSE\ 0))$
- 4: $REV = POIL * QOIL + PGAS * QGAS$

5: C = IF QOIL LE 0 THEN (IF QGAS LE 0 THEN 0 ELSE CWGAS*GASWELLS+CMCF*QGAS) ELSE (IF QGAS LE 0 THEN CWOIL*OILWELLS+CBBL*QOIL ELSE CWOIL*OILWELLS+CBBL*QOIL+CWGAS*GASWELLS+CMCF*QGAS)
 6: CAPITAL = EXPLORE+DEVELOP+DRILLING*FOOTAGE
 7: SRPLUS = REV-C
 8: GASROY = RGAS*PGAS*QGAS
 9: OILROY = ROIL*POIL*QOIL
 10: CONSVTAX = CONSRATE*QOIL
 11: OILPCT = IF YEAR GT T0+4 THEN OILPCT1 ELSE OILPCT1-0.0275*LOWOIL
 12: OILNOMRT = IF CENTSBBL GE OILPCT*POIL THEN CENTSBBL ELSE OILPCT*POIL
 13: GASNOMRT = IF CENTSMCF GE GASPCT*PGAS THEN CENTSMCF ELSE GASPCT*PGAS
 14: ELFGAS = IF QGAS LE PELGAS*GASWELLS THEN 0 ELSE (1-PELGAS*GASWELLS/QGAS)**ELGASEXP
 15: ELFCALC = IF QOIL LE PELOIL*OILWELLS THEN 0 ELSE (IF YEAR EQ TO THEN (1-PELOIL*OILWELLS/(2*QOIL))**(ELOILEXP/PELOIL) ELSE (1-PELOIL*OILWELLS/QOIL)**(ELOILEXP/PELOIL))
 16: ELFOIL = IF YEAR LT 1982 THEN ELFCALC ELSE (IF ELFCALC GE 0.7 THEN 1. ELSE ELFCALC)
 17: GASSEVRT = IF PGAS LE 0 THEN 0 ELSE GASNOMRT*ELFGAS/PGAS
 18: OILSEVRT = IF POIL LE 0 THEN 0 ELSE OILNOMRT*ELFOIL/POIL
 19: GASSEVTX = GASSEVRT*(1-RGAS)*PGAS*QGAS
 20: OILSEVTX = OILSEVRT*(1-ROIL)*POIL*QOIL
 21: SEVTAX = OILSEVTX+GASSEVTX
 22: FRTIER1 = IF YEAR LT 1980 THEN 0 ELSE 1-FREXEMPT-FRTIER2-FRTIER3
 23: TAPSADJ = IF TARIFF GE 6.26 THEN 0 ELSE 6.26-TARIFF
 24: POILBAS1 = POIL79T1*(DEFLATOR/DEF1979)+TAPSADJ
 25: POILBAS2 = POIL79T2*(DEFLATOR/DEF1979)+TAPSADJ
 26: POILBAS3 = POIL79T3*(DEFLATOR*1.02015**(YEAR-1979)/DEF1979)+TAPSADJ
 27: EXROYOIL = IF POIL LE 0 THEN 0 ELSE OILROY*(1-TXOILROY)/POIL

28: $\text{EXTAXOIL} = \text{IF OILSEVRT LT } 0.15 \text{ THEN OILSEVRT} \times (1 - \text{ROIL}) \times \text{QOIL} \text{ ELSE } 0.15 \times (1 - \text{ROIL}) \times \text{QOIL}$
 29: $\text{WPTBASE1} = \text{IF POIL LE POILBAS1 THEN } 0 \text{ ELSE } (\text{QOIL} - \text{EXTAXOIL} - \text{EXROYOIL}) \times \text{FRTIER1} \times (\text{POIL} - \text{POILBAS1})$
 30: $\text{WPTBASE2} = \text{IF POIL LE POILBAS2 THEN } 0 \text{ ELSE } (\text{QOIL} - \text{EXTAXOIL} - \text{EXROYOIL}) \times \text{FRTIER2} \times (\text{POIL} - \text{POILBAS2})$
 31: $\text{WPTBASE3} = \text{IF POIL LE POILBAS3 THEN } 0 \text{ ELSE } (\text{QOIL} - \text{EXTAXOIL} - \text{EXROYOIL}) \times \text{FRTIER3} \times (\text{POIL} - \text{POILBAS3})$
 32: $\text{WPTBASEN} = \text{IF POIL LE POILBAS3 THEN } 0 \text{ ELSE } (\text{QOIL} - \text{EXTAXOIL} - \text{EXROYOIL}) \times \text{FRTIERN} \times (\text{POIL} - \text{POILBAS3})$
 33: $\text{WINDPROF} = \text{WPTBASE1} + \text{WPTBASE2} + \text{WPTBASE3}$
 34: $\text{T1981} = \text{IF YEAR GT } 1982 \text{ THEN } 0 \text{ ELSE } 0.3$
 35: $\text{WPTAX1} = ((\text{WPRATE1} - 0.2 \times \text{FRINDEPN}) \times \text{WPTBASE1} + (\text{WPRATE2} - \text{T1981} \times \text{FRINDEPN}) \times \text{WPTBASE2} + (\text{WPRATEN}$
 $\quad \times \text{WPTBASEN} + \text{WPRATE3} \times (\text{WPTBASE3} - \text{WPTBASEN})) \times \text{PHASEOUT}$
 36: $\text{WPTAX} = \text{IF TAXINCS LE } 0 \text{ THEN } 0 \text{ ELSE } (\text{IF WINDPROF GE } 0.9 \times (\text{TAXINCS} + \text{WPTAX1}) \text{ THEN } 0.9 \times \text{WPTAX1}$
 $\quad \times \text{TAXINCS} / (\text{WINDPROF} - 0.9 \times \text{WPTAX1}) \text{ ELSE WPTAX1})$
 37: $\text{WPTAXRT} = \text{IF POIL} \times (\text{QOIL} - \text{EXROYOIL}) \text{ LE } 0 \text{ THEN } 0 \text{ ELSE WPTAX} / (\text{POIL} \times (\text{QOIL} - \text{EXROYOIL}))$
 38: $\text{NETTXROY} = (1 - \text{WPTAXRT} \times \text{TXOILROY}) \times \text{OILROY}$
 39: $\text{ROYALTY} = \text{NETTXROY} + \text{GASROY}$
 40: $\text{EXCISE} = \text{ROYALTY} + \text{SEVTAX} + \text{WPTAX} + \text{CONSVTAX}$
 41: $\text{EXCSHR} = \text{IF REV EQ } 0 \text{ THEN } 0 \text{ ELSE EXCISE} / \text{REV}$
 42: $\text{NETREV} = \text{REV} - \text{EXCISE} - \text{C}$
 43: $\text{INTANG} = \text{IF FIXED} + \text{VARIABLE LE } 0 \text{ THEN PCTINTAN} \times \text{DRILLING} \times \text{FOOTAGE} \text{ ELSE PCTINTAN}$
 $\quad \times \text{DRILLING} \times \text{FOOTAGE} + \text{PCTINTAN} \times (\text{VARIABLE} \times \text{RESERVTO} / (\text{FIXED} + \text{VARIABLE} \times \text{RESERVTO})) \times \text{DEVELOP}$
 44: $\text{TAXBASE} = \text{TAXBASE}(-1) \times (\text{DEFLATOR} / \text{DEFLATOR}(-1)) \times (1 - \text{DEPRATE}) + \text{CAPITAL} - \text{EXPLORE} - \text{INTANG}$
 45: $\text{PROPTAX} = \text{IF YEAR LE } 10 \text{ THEN PROPRATE} \times \text{TAXBASE} \text{ ELSE } (\text{IF QOIL LE } 0 \text{ THEN } 0 \text{ ELSE PROPRATE} \times \text{TAXBASE})$
 46: $\text{F} = \text{F}(-1) + \text{DEF1984} / \text{DEFLATOR} / (1 + \text{DELTA})^{**} (\text{YEAR} - 1984) \times (\text{BONUS} + \text{RENTAL} + \text{CAPITAL} + \text{PROPTAX})$
 47: $\text{RF} = \text{RF}(-1) + \text{DEF1984} / \text{DEFLATOR} / (1 + \text{DELTA})^{**} (\text{YEAR} - 1984) \times (\text{CAPITAL} + \text{PROPTAX})$
 48: $\text{OPRENT} = \text{REV} - (\text{C} + \text{DELTA} \times \text{RF})$
 49: $\text{CARENT} = \text{REV} - \text{C} - (\text{CAPITAL} + \text{PROPTAX})$

50: CAVALUE = NETREV-(BONUS+RENTAL+CAPITAL+PROPTAX)
 51: OPVALUE = NETREV-DELTA*F
 52: CUMQOIL = CUMQOIL(-1)+QOIL
 53: PDBONUS = PDBONUS(-1)+DEF1984/DEFLATOR/(1+DELTA)**(YEAR-1984)*(BONUS+RENTAL)
 54: PDREV = PDREV(-1)+DEF1984/DEFLATOR/(1+DELTA)**(YEAR-1984)*REV
 55: PDSRPLUS = PDSRPLUS(-1)+DEF1984/DEFLATOR/(1+DELTA)**(YEAR-1984)*SRPLUS
 56: PDEXCISE = PDEXCISE(-1)+DEF1984/DEFLATOR/(1+DELTA)**(YEAR-1984)*EXCISE
 57: PDOPRENT = PDOPRENT(-1)+DEF1984/DEFLATOR/(1+DELTA)**(YEAR-1984)*OPRENT
 58: PDCARENT = PDCARENT(-1)+DEF1984/DEFLATOR/(1+DELTA)**(YEAR-1984)*CARENT
 59: NPR = NPR(-1)+DEF1984/DEFLATOR/(1+DELTA)**(YEAR-1984)*NETREV
 60: PDVCASH = NPR-F
 61: PDVOP = PDVOP(-1)+DEF1984/DEFLATOR/(1+DELTA)**(YEAR-1984)*OPVALUE
 62: S = IF PDVCASH LE 0 THEN 0 ELSE NPSRATE
 63: NPS = S*CAVALUE
 64: CAINCOME = (1-S)*CAVALUE
 65: OPINCOME = (1-S)*OPVALUE
 66: PDINCOME = PDINCOME(-1)+DEF1984/DEFLATOR/(1+DELTA)**(YEAR-1984)*CAINCOME
 67: TAXINCS = NETREV-PROPTAX-0.25*(BONUS+BONUS(-1)+BONUS(-2)+BONUS(-3)+RENTAL+RENTAL(-1)+RENTAL(-2)+RENTAL(-3)+CAPITAL+CAPITAL(-1)+CAPITAL(-2)+CAPITAL(-3))-NPS-RESTAX
 68: CORPTXS = INEFFECT*SCORPRT*TAXINCS-EXPLINCR*DRILLING*FOOTAGE
 69: TAXINCF = NETREV-RENTAL-EXPLORE-INTANG-PROPTAX-0.25*(BONUS+BONUS(-1)+BONUS(-2)+BONUS(-3)+CAPITAL+CAPITAL(-1)+CAPITAL(-2)+CAPITAL(-3)-EXPLORE-EXPLORE(-1)-EXPLORE(-2)-EXPLORE(-3)-INTANG-INTANG(-1)-INTANG(-2)-INTANG(-3))-CORPTXS-NPS-RESTAX
 70: DEPALLOW = IF TAXINCF LE 0 THEN 0 ELSE (IF DEPALLRT*REV LE 0.5*TAXINCF THEN FRINDEPN*DEPALLRT*REV ELSE FRINDEPN*0.5*TAXINCF)
 71: CORPTXF = FCORPRT*TAXINCF-DEPALLOW-INVXCR*(CAPITAL-EXPLORE-INTANG)

72: CORPRATE = IF TAXINCS EQ 0 THEN 0 ELSE (CORPTXF+CORPTXS)/TAXINCS
 73: CAAFTAX = CAINCOME-CORPTXF-CORPTXS-RESTAX
 74: OPAFTAX = OPINCOME-CORPTXF-CORPTXS-RESTAX
 75: PDAFTAX = PDAFTAX(-1)+DEF1984/DEFLATOR/(1+DELTA)**(YEAR-1984)*CAAFTAX
 76: AFTPROF = TAXINCS-CORPTXF-CORPTXS-RESTAX
 77: PDAFTPRO = PDAFTPRO(-1)+AFTPROF*(DEF1984/DEFLATOR)/(1+DELTA)**(YEAR-1984)
 78: RESTAX = RESRATE*(TAXINCS+ROYALTY)/(DELTA+GAMMA)
 79: RESERVES = RESERVTO-CUMQOIL
 80: QOIL = IF YEAR LT TO THEN 0 ELSE (IF YEAR EQ TO THEN CAPOIL*365/2 ELSE (IF YEAR LE TO+NOIL
 THEN CAPOIL*365 ELSE (IF QOIL(-1)*(1-GAMMA) LE CWOIL*OILWELLS/(QOIL*(1-EXCSHR(-1))-CBBL) THEN
 0 ELSE QOIL(-1)*(1-GAMMA))))

TABLE F.1.
BASE CASE ASSUMPTIONS FOR ALASKA
NORTH SLOPE OIL PROJECTIONS

	<u>RESERVTO</u>	<u>CAPOIL</u>	<u>TO</u>	<u>NOIL</u>	<u>POILBASE</u>
ENDICOTT	350.	0.085	1987.	3.	16.5
FLAXMAN	300.	0.08	1990.	1.	15.
GWYDYR	35.	0.01	1987.	2.	15.5
KUPARUK1	520.	0.11	1982.	4.	16.
KUPARUK2	520.	0.11	1985.	4.	16.
LISBURNE	475.	0.1	1987.	5.	17.5
MILNEPT1	65.	0.03	1986.	2.	15.5
MILNEPT2	60.	0.03	1990.	1.	15.5
PRUDHOE	7565.	1.534	1982.	5.	17.5
PRUDEOR	7565.	1.534	1982.	6.	17.5
SEALISL	350.	0.085	1992.	3.	17.5
WESTSAK1	1150.	0.15	1989.	8.	15.5
WESTSAK2	6200.	0.6	1992.	10.	15.5

	<u>FIXED</u>	<u>VARIABLE</u>	<u>EXPLORE</u>	<u>FOOTAGE</u>	<u>OILWELLS</u>
ENDICOTT	1300.	2.6	0.	0.	60.
FLAXMAN	1050.	2.7	0.	0.	60.
GWYDYR	270.	2.9	0.	0.	12.
KUPARUK1	0.	3.3	0.	0.	85.
KUPARUK2	0.	3.5	0.	0.	85.
LISBURNE	540.	1.8	0.	0.	180.
MILNEPT1	312.	0.	0.	0.	45.
MILNEPT2	376.	0.	0.	0.	60.
PRUDHOE	0.	0.	2000.	0.324	454.
PRUDEOR	0.	0.	2000.	0.324	454.
SEALISL	840.	1.7	0.	0.	60.
WESTSAK1	0.	3.5	0.	0.	0.
WESTSAK2	2700.	3.8	0.	0.	2000.

	<u>CWOIL</u>	<u>ROIL</u>	<u>LOWOIL</u>	<u>NPSRATE</u>	<u>FREXEMPT</u>
ENDICOTT	0.85	0.2	1.	0.3	1.
FLAXMAN	0.85	0.121	1.	0.	1.
GWYDYR	0.85	0.121	1.	0.	1.
KUPARUK1	0.85	0.121	1.	0.	1.
KUPARUK2	0.85	0.121	1.	0.	1.
LISBURNE	0.85	0.121	0.	0.	1.
MILNEPT1	0.85	0.2	1.	0.3	1.
MILNEPT2	0.85	0.2	1.	0.3	1.
PRUDHOE	0.85	0.121	0.	0.	0.
PRUDEOR	0.85	0.121	0.	0.	0.
SEALISL	0.62	0.2	1.	0.6	1.
WESTSAK1	0.85	0.121	1.	0.	1.
WESTSAK2	0.85	0.121	1.	0.	1.

TABLE F.2.
BASECASE PROJECTION, ENDICOTT FIELD

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	0.	0.	0.	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	4.418	0.	-3.466	-107.772
1986	0.	0.	0.	0.	12.593	-0.	-10.372	-241.095
1987	15.512	51.191	17.415	0.	19.541	-0.	-12.106	-231.594
1988	31.025	102.382	34.83	0.	18.519	-0.	-6.449	-30.078
1989	31.025	102.382	34.83	0.	17.65	-0.	-4.543	-16.127
1990	31.025	102.382	34.83	0.	16.912	0.	0.658	21.214
1991	27.279	90.019	28.909	0.	14.375	0.	5.716	85.633
1992	23.985	79.149	29.069	0.	12.219	0.	5.582	77.718
1993	21.088	69.591	23.557	0.	10.386	0.	5.846	74.481
1994	18.542	61.188	18.771	0.	8.828	0.	6.246	72.83
1995	16.303	53.799	14.636	0.	7.504	0.	5.341	62.25
1996	14.334	47.303	11.085	0.	6.378	0.	4.539	52.894
1997	12.603	41.59	8.065	0.	5.422	0.	3.83	44.607
1998	11.081	36.568	5.531	0.	4.608	0.	3.201	37.255
1999	9.743	32.152	3.454	0.	3.917	0.	2.641	30.713
2000	8.567	28.27	1.818	0.	3.33	0.	2.14	24.868
2001	7.532	24.856	0.636	0.	2.83	0.	1.69	19.618
2002	6.623	21.855	0.008	0.	2.406	0.	1.278	14.838
2003	5.823	19.216	0.	0.	2.045	0.	0.895	10.392
2004	5.12	16.895	0.	0.	1.738	0.	0.558	6.475
2005	4.502	14.855	0.	0.	1.477	-0.	0.261	3.028
2006	3.958	13.061	0.	0.	1.256	0.	-0.001	-0.007
2007	0.	0.	0.	0.	0.	0.	0.	0.
2008	0.	0.	0.	0.	0.	0.	0.	0.
2009	0.	0.	0.	0.	0.	0.	0.	0.
2010	0.	0.	0.	0.	0.	0.	0.	0.

	<u>CUMOOIL</u>	<u>PDREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>
2010	305.667	2267.73	1804.25	104.64	591.305	-210.462	8.913

SIMULATION OUTPUT BY DSET FINDOIL ENDICOTT BASE

TABLE F.3.
BASECASE PROJECTION, FLAXMAN FIELD

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	0.	0.	0.	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	0.	0.	0.	0.
1986	0.	0.	0.	0.	0.	0.	0.	0.
1987	0.	0.	0.	0.	0.	0.	0.	0.
1988	0.	0.	0.	0.	3.539	0.	-2.868	-90.816
1989	0.	0.	0.	0.	10.086	0.	-8.585	-202.055
1990	14.6	26.419	15.959	0.	15.651	-0.	-9.543	-187.095
1991	29.2	52.839	31.918	0.	18.229	-0.	-6.806	-93.948
1992	26.051	47.141	26.959	0.	15.494	0.	-5.343	7.698
1993	23.242	42.058	22.565	0.	13.17	0.	-1.013	32.101
1994	20.736	37.523	18.681	0.	11.195	0.	3.435	57.975
1995	18.5	33.477	18.68	0.	9.515	0.	6.197	72.311
1996	16.505	29.867	14.996	0.	8.088	0.	5.4	62.996
1997	14.726	26.646	11.774	0.	6.875	0.	4.684	54.63
1998	13.138	23.773	8.978	0.	5.844	0.	4.04	47.109
1999	11.721	21.21	6.574	0.	4.967	0.	3.461	40.34
2000	10.457	18.923	4.537	0.	4.222	0.	2.939	34.236
2001	9.33	16.882	2.851	0.	3.589	0.	2.467	28.718
2002	8.324	15.062	1.512	0.	3.05	0.	2.039	23.711
2003	7.426	13.438	0.535	0.	2.593	0.	1.647	19.137
2004	6.625	11.989	0.009	0.	2.204	0.	1.285	14.914
2005	5.911	10.696	0.	0.	1.873	0.	0.943	10.949
2006	5.274	9.543	0.	0.	1.592	0.	0.638	7.403
2007	4.705	8.514	0.	0.	1.353	0.	0.365	4.234
2008	4.198	7.596	0.	0.	1.15	0.	0.121	1.402
2009	0.	0.	0.	0.	0.	0.	0.	0.
2010	0.	0.	0.	0.	0.	0.	0.	0.

	<u>CUMOOIL</u>	<u>PDREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>
2010	250.668	1285.82	1154.76	-133.84	230.546	-163.274	-22.61

SIMULATION OUTPUT BY DSET FINDOIL FLAXMAN BASE

TABLE F.4.
BASECASE PROJECTION, KUPARUK PHASE I

	<u>QOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	40.15	77.497	46.184	0.	12.795	0.	6.223	91.974
1984	40.15	77.497	46.184	0.	11.81	0.	5.857	92.1
1985	40.15	77.497	46.184	0.	10.468	0.	7.117	93.597
1986	40.15	77.497	46.184	0.	9.327	0.	8.369	95.005
1987	35.665	68.839	47.34	0.	7.928	-0.	8.022	159.721
1988	31.68	61.149	39.222	0.	6.739	0.	8.281	140.715
1989	28.141	54.318	32.085	0.	5.728	0.	8.731	123.952
1990	24.997	48.25	25.83	0.	4.869	0.	9.352	109.178
1991	22.205	42.859	20.372	0.	4.138	0.	8.108	94.629
1992	19.724	38.071	15.64	0.	3.518	0.	6.997	81.642
1993	17.521	33.818	11.572	0.	2.99	0.	6.004	70.035
1994	15.563	30.04	8.12	0.	2.541	0.	5.115	59.645
1995	13.825	26.684	5.25	0.	2.16	0.	4.318	50.32
1996	12.28	23.703	2.945	0.	1.836	0.	3.6	41.923
1997	10.909	21.055	1.214	0.	1.561	0.	2.949	34.318
1998	9.69	18.703	0.144	0.	1.327	0.	2.354	27.351
1999	8.607	16.614	0.	0.	1.128	0.	1.794	20.826
2000	7.646	14.758	0.	0.	0.959	0.	1.292	14.995
2001	6.792	13.109	0.	0.	0.815	0.	0.845	9.813
2002	6.033	11.645	0.	0.	0.693	0.	0.449	5.208
2003	5.359	10.344	0.	0.	0.589	0.	0.096	1.115
2004	0.	0.	0.	0.	0.	0.	0.	0.
2005	0.	0.	0.	0.	0.	0.	0.	0.
2006	0.	0.	0.	0.	0.	0.	0.	0.
2007	0.	0.	0.	0.	0.	0.	0.	0.
2008	0.	0.	0.	0.	0.	0.	0.	0.
2009	0.	0.	0.	0.	0.	0.	0.	0.
2010	0.	0.	0.	0.	0.	0.	0.	0.
	<u>CUMQOIL</u>	<u>PDREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>	
2010	437.236	4665.5	903.339	3002.4	868.512	1152.96	770.211	

SIMULATION OUTPUT BY DSET FINDOIL KUPARUK1 BASE

TABLE F.5.
BASECASE PROJECTION, KUPARUK PHASE II

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	0.	0.	0.	0.	0.364	-0.	-1.724	-78.635
1984	0.	0.	0.	0.	1.052	0.	-5.172	-158.719
1985	20.075	38.748	23.092	0.	1.622	0.	-1.581	-78.761
1986	40.15	77.497	46.184	0.	1.834	0.	6.024	90.862
1987	40.15	77.497	46.184	0.	2.014	0.	5.589	90.462
1988	40.15	77.497	46.184	0.	2.167	0.	6.867	91.361
1989	40.15	77.497	46.184	0.	2.297	0.	8.145	92.27
1990	35.665	68.839	47.34	0.	1.952	-0.	7.88	162.087
1991	31.68	61.149	39.222	0.	1.659	0.	8.227	142.777
1992	28.141	54.318	32.085	0.	1.41	0.	8.772	125.77
1993	24.997	48.25	25.83	0.	1.199	0.	9.49	110.803
1994	22.205	42.859	20.372	0.	1.019	0.	8.225	96.01
1995	19.724	38.071	15.64	0.	0.866	0.	7.096	82.816
1996	17.521	33.818	11.572	0.	0.736	0.	6.089	71.033
1997	15.563	30.04	8.12	0.	0.626	0.	5.187	60.493
1998	13.825	26.684	5.25	0.	0.532	0.	4.379	51.041
1999	12.28	23.703	2.945	0.	0.452	0.	3.652	42.536
2000	10.909	21.055	1.214	0.	0.384	0.	2.994	34.839
2001	9.69	18.703	0.144	0.	0.327	0.	2.391	27.794
2002	8.607	16.614	0.	0.	0.278	0.	1.826	21.197
2003	7.646	14.758	0.	0.	0.236	0.	1.319	15.31
2004	6.792	13.109	0.	0.	0.201	0.	0.869	10.081
2005	6.033	11.645	0.	0.	0.171	0.	0.468	5.436
2006	5.359	10.344	0.	0.	0.145	0.	0.113	1.309
2007	0.	0.	0.	0.	0.	0.	0.	0.
2008	0.	0.	0.	0.	0.	0.	0.	0.
2009	0.	0.	0.	0.	0.	0.	0.	0.
2010	0.	0.	0.	0.	0.	0.	0.	0.

	<u>CUMOOIL</u>	<u>PDREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>
2010	457.311	3772.6	1573.67	1565.17	704.012	457.087	663.003

SIMULATION OUTPUT BY DSET FINDOIL KUPARUK2 BASE

TABLE F.6.
BASECASE PROJECTIONS, LISBURNE FIELD

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	0.	0.	0.	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	1.735	0.	-1.884	-67.685
1986	0.	0.	0.	0.	4.945	0.	-5.643	-145.163
1987	18.25	38.528	0.	0.	7.674	-0.	-4.577	-108.065
1988	36.5	77.056	25.615	0.	7.29	0.	4.23	89.729
1989	36.5	77.056	25.615	0.	6.963	0.	5.257	94.902
1990	36.5	77.056	25.615	0.	6.685	0.	8.102	109.188
1991	36.5	77.056	25.615	0.	6.449	0.	10.945	123.536
1992	36.5	77.056	25.615	0.	6.249	0.	10.952	123.624
1993	31.945	67.441	16.929	0.	5.311	0.	9.483	126.611
1994	27.959	59.025	9.93	0.	4.515	0.	8.273	107.109
1995	24.47	51.659	4.589	0.	3.837	0.	7.284	90.189
1996	21.417	45.213	1.022	0.	3.262	0.	6.477	75.386
1997	18.744	39.571	0.	0.	2.773	0.	4.988	57.959
1998	16.405	34.633	0.	0.	2.357	0.	3.65	42.369
1999	14.358	30.311	0.	0.	2.003	0.	2.479	28.775
2000	12.566	26.529	0.	0.	1.703	0.	1.454	16.874
2001	10.998	23.218	0.	0.	1.447	0.	0.556	6.454
2002	0.	0.	0.	0.	0.	0.	0.	0.
2003	0.	0.	0.	0.	0.	0.	0.	0.
2004	0.	0.	0.	0.	0.	0.	0.	0.
2005	0.	0.	0.	0.	0.	0.	0.	0.
2006	0.	0.	0.	0.	0.	0.	0.	0.
2007	0.	0.	0.	0.	0.	0.	0.	0.
2008	0.	0.	0.	0.	0.	0.	0.	0.
2009	0.	0.	0.	0.	0.	0.	0.	0.
2010	0.	0.	0.	0.	0.	0.	0.	0.
	<u>CUMOOIL</u>	<u>PDREV</u>	<u>F</u>	<u>POCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>	
2010	379.611	3071.12	1069.68	1039.67	456.6	325.546	457.681	

SIMULATION OUTPUT BY DSET FINDOIL LISBURNE BASE

TABLE F.7.
BASECASE PROJECTIONS, MILNE POINT PHASE I

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	0.	0.	0.	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	1.248	0.	-0.633	-13.699
1985	0.	0.	0.	0.	3.557	0.	-1.893	-34.773
1986	5.475	16.972	3.325	0.	5.519	0.	-2.151	-37.808
1987	10.95	33.945	6.651	0.	4.691	0.	0.307	3.568
1988	10.95	33.945	6.651	0.	3.988	0.	0.92	10.683
1989	8.168	25.321	3.006	0.	3.39	0.	0.956	11.098
1990	6.093	18.888	0.733	0.	2.881	0.	1.266	14.7
1991	4.545	14.089	0.	0.	2.449	-0.	0.589	6.831
1992	3.39	10.51	0.	0.	2.082	0.	0.064	0.743
1993	0.	0.	0.	0.	0.	0.	0.	0.
1994	0.	0.	0.	0.	0.	0.	0.	0.
1995	0.	0.	0.	0.	0.	0.	0.	0.
1996	0.	0.	0.	0.	0.	0.	0.	0.
1997	0.	0.	0.	0.	0.	0.	0.	0.
1998	0.	0.	0.	0.	0.	0.	0.	0.
1999	0.	0.	0.	0.	0.	0.	0.	0.
2000	0.	0.	0.	0.	0.	0.	0.	0.
2001	0.	0.	0.	0.	0.	0.	0.	0.
2002	0.	0.	0.	0.	0.	0.	0.	0.
2003	0.	0.	0.	0.	0.	0.	0.	0.
2004	0.	0.	0.	0.	0.	0.	0.	0.
2005	0.	0.	0.	0.	0.	0.	0.	0.
2006	0.	0.	0.	0.	0.	0.	0.	0.
2007	0.	0.	0.	0.	0.	0.	0.	0.
2008	0.	0.	0.	0.	0.	0.	0.	0.
2009	0.	0.	0.	0.	0.	0.	0.	0.
2010	0.	0.	0.	0.	0.	0.	0.	0.

	<u>CUMOOIL</u>	<u>PDREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>
2010	49.571	506.162	300.244	36.628	115.841	-30.042	5.749

SIMULATION OUTPUT BY DSET FINDOIL MILNEPT1 BASE

TABLE F.8.
BASECASE PROJECTION, MILNE POINT PHASE II

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	0.	0.	0.	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	0.	0.	0.	0.
1986	0.	0.	0.	0.	0.	0.	0.	0.
1987	0.	0.	0.	0.	0.	0.	0.	0.
1988	0.	0.	0.	0.	1.504	0.	-0.763	-16.509
1989	0.	0.	0.	0.	4.286	0.	-2.282	-41.906
1990	5.475	16.972	4.813	0.	6.651	-0.	-2.372	-42.966
1991	10.95	33.945	9.626	0.	5.654	0.	0.037	0.431
1992	10.95	33.945	9.626	0.	4.806	0.	0.776	9.006
1993	8.168	25.321	5.637	0.	4.085	0.	1.07	12.417
1994	6.093	18.888	2.822	0.	3.472	0.	1.645	19.147
1995	4.545	14.089	1.182	0.	2.951	0.	1.005	11.663
1996	3.39	10.51	0.031	0.	2.509	0.	0.526	6.108
1997	2.529	7.84	0.	0.	2.132	0.	0.14	1.625
1998	0.	0.	0.	0.	0.	0.	0.	0.
1999	0.	0.	0.	0.	0.	0.	0.	0.
2000	0.	0.	0.	0.	0.	0.	0.	0.
2001	0.	0.	0.	0.	0.	0.	0.	0.
2002	0.	0.	0.	0.	0.	0.	0.	0.
2003	0.	0.	0.	0.	0.	0.	0.	0.
2004	0.	0.	0.	0.	0.	0.	0.	0.
2005	0.	0.	0.	0.	0.	0.	0.	0.
2006	0.	0.	0.	0.	0.	0.	0.	0.
2007	0.	0.	0.	0.	0.	0.	0.	0.
2008	0.	0.	0.	0.	0.	0.	0.	0.
2009	0.	0.	0.	0.	0.	0.	0.	0.
2010	0.	0.	0.	0.	0.	0.	0.	0.

	<u>CUMOOIL</u>	<u>PDREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>
2010	52.1	357.07	247.756	24.844	87.493	-23.427	6.033

SIMULATION OUTPUT BY DSET FINDOIL MILNEPT2 BASE

TABLE F.9.
BASECASE PROJECTION, PRUDHOE BAY FIELD

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	559.91	1182.04	1292.46	284.805	79.999	0.	199.016	1422.22
1984	559.91	1182.04	1292.46	61.709	71.451	0.	189.948	2015.37
1985	559.91	1182.04	1292.46	61.709	60.885	0.	181.162	2276.48
1986	559.91	1182.04	1292.46	61.709	52.882	0.	173.116	2234.02
1987	559.91	1182.04	1292.46	61.709	44.949	0.	199.48	2941.75
1988	494.124	1043.16	1140.6	54.458	38.207	0.	191.74	2608.39
1989	436.068	920.596	1006.59	48.06	32.476	0.	178.045	2269.15
1990	384.832	812.431	888.319	42.413	27.605	0.	169.873	1984.34
1991	339.617	716.976	783.947	23.955	23.464	0.	149.094	1741.53
1992	299.714	632.736	691.838	9.249	19.944	0.	130.668	1526.21
1993	264.5	558.393	610.552	0.	16.953	0.	114.545	1337.83
1994	233.423	492.785	375.603	0.	14.41	0.	106.102	1239.69
1995	205.997	434.886	322.788	0.	12.248	0.	93.164	1088.48
1996	181.794	383.79	277.329	0.	10.411	0.	81.802	955.693
1997	160.434	338.697	236.347	0.	8.849	0.	71.714	837.8
1998	141.584	298.902	201.097	0.	7.522	0.	62.855	734.258
1999	124.949	263.783	169.919	0.	6.394	0.	55.02	642.693
2000	110.268	232.79	137.526	0.	5.435	0.	47.78	558.052
2001	97.312	205.439	119.457	0.	4.619	0.	42.049	491.103
2002	85.879	181.301	94.655	0.	3.927	0.	36.393	424.971
2003	75.789	159.999	73.205	0.	3.338	0.	31.383	366.404
2004	66.884	141.201	54.793	0.	2.837	0.	26.942	314.482
2005	59.025	124.61	39.16	0.	2.411	0.	22.999	268.38
2006	52.09	109.969	26.111	0.	2.05	0.	19.491	227.358
2007	45.97	97.049	15.517	0.	1.742	0.	16.36	190.742
2008	40.569	85.646	7.354	0.	1.481	0.	13.552	157.899
2009	35.802	75.583	1.801	0.	1.259	0.	11.011	128.181
2010	31.596	66.703	0.	0.	1.07	0.	8.652	100.578

	<u>CUMQOIL</u>	<u>PDREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDRAFTAX</u>	<u>PDRAFTPRO</u>
2010	6767.72	75127.6	9148.88	61616.2	19213.3	22268.1	22288.1

SIMULATION OUTPUT BY DSET FINDOIL PRUDHOE BASE

TABLE F.10.
BASECASE PROJECTION, PRUDHOE BAY WITH ENHANCED OIL RECOVERY

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	559.91	1182.04	1292.46	284.805	79.999	-0.	197.973	1372.35
1984	559.91	1182.04	1292.46	61.709	71.451	0.	188.905	2015.85
1985	559.91	1182.04	1292.46	61.709	60.885	0.	180.119	2276.96
1986	559.91	1182.04	1292.46	61.709	52.882	0.	169.723	2120.58
1987	559.91	1182.04	1292.46	60.783	44.949	0.	193.122	2792.15
1988	508.445	1073.39	1173.66	54.299	38.207	0.	192.628	2681.51
1989	448.694	947.252	1035.73	47.918	32.476	0.	177.871	2329.84
1990	395.965	835.935	914.018	42.287	27.605	0.	171.351	2035.78
1991	349.433	737.698	806.605	23.883	23.464	0.	152.785	1784.59
1992	308.369	651.006	711.816	9.221	19.944	0.	133.822	1562.99
1993	272.13	574.503	628.166	0.	16.953	0.	117.247	1369.32
1994	240.151	506.989	554.346	0.	14.41	0.	102.265	1194.24
1995	211.929	447.41	336.189	0.	12.248	0.	95.145	1111.56
1996	187.024	394.832	289.111	0.	10.411	0.	83.498	975.455
1997	165.046	348.433	246.695	0.	8.849	0.	73.154	854.564
1998	145.65	307.487	210.182	0.	7.522	0.	64.074	748.446
1999	128.534	271.352	177.885	0.	6.394	0.	56.795	663.442
2000	113.429	239.464	144.466	0.	5.435	0.	49.348	576.383
2001	100.099	211.323	125.561	0.	4.619	0.	43.432	507.273
2002	88.336	186.489	99.948	0.	3.927	0.	37.615	439.267
2003	77.955	164.574	77.767	0.	3.338	-0.	32.465	379.056
2004	68.794	145.233	58.69	0.	2.837	0.	27.901	325.692
2005	60.71	128.166	42.448	0.	2.411	0.	23.85	278.329
2006	53.575	113.105	28.828	0.	2.05	0.	20.248	236.21
2007	47.279	99.813	17.687	0.	1.742	0.	17.036	198.648
2008	41.723	89.083	8.971	0.	1.481	0.	14.159	165.001
2009	36.82	77.732	2.794	0.	1.259	0.	11.563	134.633
2010	32.493	68.597	0.	0.	1.07	0.	9.171	106.655

	<u>CUMOOIL</u>	<u>PDREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>
2010	6882.09	75984.9	9708.66	61753.6	19490.2	22195.2	22290.6

SIMULATION OUTPUT BY DSET FINDOIL PRUDEOR BASE

TABLE F.11.
BASECASE PROJECTION, GWYDYR BAY FIELD

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	0.	0.	0.	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	0.968	0.	-0.639	-17.808
1986	0.	0.	0.	0.	2.757	0.	-1.913	-41.266
1987	1.825	3.412	1.537	0.	4.279	-0.	-2.682	-46.696
1988	3.65	6.825	3.074	0.	4.02	-0.	-2.033	-18.937
1989	3.65	6.825	3.074	0.	3.799	-0.	-1.661	-15.645
1990	3.169	5.926	2.328	0.	3.23	-0.	-0.652	-2.609
1991	2.751	5.145	1.698	0.	2.745	0.	0.382	5.853
1992	2.389	4.467	1.435	0.	2.333	0.	0.46	6.052
1993	2.074	3.878	0.91	0.	1.983	0.	0.571	6.643
1994	1.801	3.367	0.495	0.	1.686	0.	0.457	5.319
1995	1.564	2.924	0.192	0.	1.433	0.	0.357	4.142
1996	1.357	2.538	0.014	0.	1.218	0.	0.266	3.085
1997	1.179	2.278	0.	0.	1.035	0.	0.182	2.107
1998	1.023	1.918	0.	0.	0.88	0.	0.108	1.251
1999	0.888	1.661	0.	0.	0.748	0.	0.044	0.507
2000	0.771	1.442	0.	0.	0.636	0.	-0.012	-0.143
2001	0.	0.	0.	0.	0.	0.	0.	0.
2002	0.	0.	0.	0.	0.	0.	0.	0.
2003	0.	0.	0.	0.	0.	0.	0.	0.
2004	0.	0.	0.	0.	0.	0.	0.	0.
2005	0.	0.	0.	0.	0.	0.	0.	0.
2006	0.	0.	0.	0.	0.	0.	0.	0.
2007	0.	0.	0.	0.	0.	0.	0.	0.
2008	0.	0.	0.	0.	0.	0.	0.	0.
2009	0.	0.	0.	0.	0.	0.	0.	0.
2010	0.	0.	0.	0.	0.	0.	0.	0.

	<u>CUMOOIL</u>	<u>PDREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>
2010	28.092	216.872	312.86	-158.089	34.847	-91.762	-54.067

SIMULATION OUTPUT BY DSET FINDOIL GWYDYR BASE

TABLE F.12.
BASECASE PROJECTION, SEAL ISLAND FIELD

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	0.	0.	0.	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	0.	0.	0.	0.
1986	0.	0.	0.	0.	0.	0.	0.	0.
1987	0.	0.	0.	0.	0.	0.	0.	0.
1988	0.	0.	0.	0.	0.	0.	0.	0.
1989	0.	0.	0.	0.	0.	0.	0.	0.
1990	0.	0.	0.	0.	2.852	0.	-2.246	-69.991
1991	0.	0.	0.	0.	8.128	0.	-6.721	-156.471
1992	15.512	54.294	18.471	0.	12.613	0.	-5.095	-117.798
1993	31.025	108.587	36.941	0.	11.964	0.	1.468	46.361
1994	31.025	108.587	36.941	0.	11.413	0.	2.695	55.175
1995	31.025	108.587	36.941	0.	10.944	0.	6.057	79.15
1996	27.279	95.475	30.661	0.	9.303	0.	8.66	113.616
1997	23.985	83.946	30.831	0.	7.907	0.	7.905	100.599
1998	21.088	73.809	24.984	0.	6.721	135.782	2.471	32.883
1999	18.542	64.896	19.909	0.	5.713	118.044	2.959	34.347
2000	16.303	57.06	15.523	0.	4.856	102.383	2.566	29.73
2001	14.334	50.169	11.757	0.	4.128	88.545	2.22	25.764
2002	12.603	44.111	8.553	0.	3.508	76.3	1.913	22.201
2003	11.081	38.784	5.866	0.	2.982	65.445	1.64	19.042
2004	9.743	34.101	3.663	0.	2.535	55.796	1.399	16.235
2005	8.567	29.983	1.928	0.	2.155	47.184	1.183	13.729
2006	7.532	26.363	0.674	0.	1.831	39.441	0.989	11.476
2007	6.623	23.179	0.008	0.	1.557	32.366	0.811	9.417
2008	5.823	20.38	0.	0.	1.323	25.794	0.647	7.505
2009	5.12	17.919	0.	0.	1.125	20.007	0.502	5.821
2010	4.502	15.755	0.	0.	0.956	14.916	0.374	4.34

	<u>CUMOOIL</u>	<u>POREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>
2010	301.71	1488.14	726.959	601.495	388.344	47.407	135.824

SIMULATION OUTPUT BY DSET FINDOIL SEALISL BASE

TABLE F.13.
BASECASE PROJECTION, WEST SAK PHASE I

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	0.	0.	0.	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	0.	0.	0.	0.
1986	0.	0.	0.	0.	0.	0.	0.	0.
1987	0.	0.	0.	0.	0.805	0.	-3.814	-173.904
1988	0.	0.	0.	0.	2.294	-0.	-11.437	-351.
1989	27.375	51.187	0.	0.	3.56	-0.	-17.807	-342.688
1990	54.75	102.375	7.749	0.	3.529	-0.	-6.434	51.146
1991	54.75	102.375	5.504	0.	3.503	0.	-5.569	45.786
1992	54.75	102.375	3.541	0.	3.481	0.	-0.931	43.149
1993	54.75	102.375	1.901	0.	3.462	-0.	3.694	40.368
1994	54.75	102.375	0.804	0.	3.446	0.	3.097	33.434
1995	54.75	102.375	0.804	0.	3.432	0.	3.098	33.44
1996	54.75	102.375	0.804	0.	3.42	0.	3.098	33.445
1997	54.75	102.375	0.804	0.	3.41	0.	3.098	33.45
1998	50.54	94.502	0.	0.	2.899	0.	3.355	115.952
1999	46.654	87.236	0.	0.	2.464	0.	3.745	94.804
2000	43.066	80.528	0.	0.	2.094	0.	4.285	75.406
2001	39.755	74.335	0.	0.	1.78	0.	4.964	57.624
2002	36.698	68.619	0.	0.	1.513	0.	3.408	39.557
2003	33.876	63.343	0.	0.	1.286	-0.	1.97	22.87
2004	31.271	58.472	0.	0.	1.093	-0.	0.643	7.46
2005	0.	0.	0.	0.	0.	0.	0.	0.
2006	0.	0.	0.	0.	0.	0.	0.	0.
2007	0.	0.	0.	0.	0.	0.	0.	0.
2008	0.	0.	0.	0.	0.	0.	0.	0.
2009	0.	0.	0.	0.	0.	0.	0.	0.
2010	0.	0.	0.	0.	0.	0.	0.	0.

	<u>CUMOOIL</u>	<u>PDREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>
2010	747.231	3981.41	2204.08	-273.061	491.36	-390.62	-110.266

SIMULATION OUTPUT BY DSET FINDOIL WESTSAK1 BASE

TABLE F.14.
BASECASE PROJECTION, WEST SAK PHASE II

	<u>OOIL</u>	<u>ROYALTY</u>	<u>SEVTAX</u>	<u>WPTAX</u>	<u>PROPTAX</u>	<u>NPS</u>	<u>CORPTXS</u>	<u>CORPTXF</u>
1983	0.	0.	0.	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	0.	0.	0.	0.
1986	0.	0.	0.	0.	0.	0.	0.	0.
1987	0.	0.	0.	0.	0.	0.	0.	0.
1988	0.	0.	0.	0.	0.	0.	0.	0.
1989	0.	0.	0.	0.	0.	0.	0.	0.
1990	0.	0.	0.	0.	11.152	0.	-27.642	-1187.97
1991	0.	0.	0.	0.	31.782	0.	-82.862	-2431.72
1992	109.5	204.749	0.	0.	49.318	-0.	-145.773	-2634.61
1993	219.	409.499	0.	0.	46.457	-0.	-100.626	-191.032
1994	219.	409.499	0.	0.	44.024	-0.	-84.385	-159.342
1995	219.	409.499	0.	0.	41.957	-0.	-40.936	-76.216
1996	219.	409.499	0.	0.	40.2	0.	2.501	6.356
1997	219.	409.499	0.	0.	38.706	0.	2.558	7.008
1998	219.	409.499	0.	0.	37.436	0.	2.605	7.562
1999	219.	409.499	0.	0.	36.357	0.	2.646	8.033
2000	219.	409.499	0.	0.	35.439	0.	2.68	8.433
2001	219.	409.499	0.	0.	34.66	0.	2.71	8.774
2002	219.	409.499	0.	0.	33.997	0.	2.735	9.063
2003	207.04	387.135	0.	0.	28.897	-0.	7.871	414.883
2004	195.733	365.992	0.	0.	24.563	0.	13.312	370.209
2005	185.043	346.004	0.	0.	20.878	0.	19.046	328.925
2006	174.937	327.107	0.	0.	17.747	0.	25.059	290.872
2007	165.383	309.243	0.	0.	15.085	0.	20.263	235.204
2008	156.351	292.354	0.	0.	12.822	0.	15.719	182.465
2009	147.812	276.387	0.	0.	10.899	0.	11.416	132.513
2010	139.74	261.293	0.	0.	9.264	0.	7.341	85.209

	<u>CUMOOIL</u>	<u>PDREV</u>	<u>F</u>	<u>PDCARENT</u>	<u>PDEXCISE</u>	<u>PDAFTAX</u>	<u>PDAFTPRO</u>
2010	3671.54	13144.1	10864.1	-5017.4	1586.71	-3371.07	-2000.25

SIMULATION OUTPUT BY DSET FINDOIL WESTSAK2 BASE

APPENDIX G

ALASKA NORTH SLOPE PETROLEUM PROJECTIONS

TABLE G.1.
PROJECTED ALASKA NORTH SLOPE OIL PRODUCTION: LOW CASE
(MILLION BARRELS)

	<u>PRUDHOE BAY</u>	<u>KUPARUK</u>	<u>MILNE POINT</u>	<u>LISBURN</u>	<u>ENDICOTT</u>	<u>GWYDYR BAY</u>	<u>WEST SAK</u>	<u>FLAXMAN</u>	<u>SEAL ISLAND</u>
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	40.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1986	559.9	40.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1987	559.9	35.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1988	494.1	31.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1989	436.1	28.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1990	384.8	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1991	339.6	22.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1992	299.7	19.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1993	264.5	17.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1994	233.4	15.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1995	206.0	13.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1996	181.8	12.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1997	160.4	10.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1998	141.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1999	124.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2000	110.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2001	97.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2002	85.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	75.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2004	66.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	59.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	52.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2007	46.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	40.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	35.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	31.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE G.2.
PROJECTED ALASKA NORTH SLOPE OIL PRODUCTION: HIGH CASE
(MILLION BARRELS)

	<u>PRUDHOE BAY</u>	<u>KUPARUK</u>	<u>MILNE POINT</u>	<u>LISBURNE</u>	<u>ENDICOTT</u>	<u>GWYDYR BAY</u>	<u>WEST SAK</u>	<u>FLAXMAN</u>	<u>SEAL ISLAND</u>
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	27.4	0.0	0.0
1990	396.0	60.7	11.6	36.5	31.0	0.0	54.7	14.6	0.0
1991	349.4	53.9	15.5	36.5	27.3	0.0	54.7	29.2	0.0
1992	308.4	47.9	14.3	36.5	24.0	0.0	164.2	26.1	15.5
1993	272.1	42.5	10.7	31.9	21.1	0.0	273.7	23.2	31.0
1994	240.2	37.8	6.1	28.0	18.5	0.0	273.7	20.7	31.0
1995	211.9	33.5	4.5	24.5	16.3	0.0	273.7	18.5	31.0
1996	187.0	29.8	3.4	21.4	14.3	0.0	273.7	16.5	27.3
1997	165.0	26.5	2.5	18.7	12.6	0.0	273.7	14.7	24.0
1998	145.7	23.5	1.9	16.4	11.1	0.0	269.5	13.1	21.1
1999	128.5	20.9	1.4	14.4	9.7	0.0	265.7	11.7	18.5
2000	113.4	18.6	0.0	12.6	8.6	0.0	262.1	10.5	16.3
2001	100.1	16.5	0.0	11.0	7.5	0.0	258.8	9.3	14.3
2002	88.3	14.6	0.0	9.6	6.6	0.0	255.7	8.3	12.6
2003	78.0	13.0	0.0	8.4	5.8	0.0	240.9	7.4	11.1
2004	68.8	11.6	0.0	7.4	5.1	0.0	227.0	6.6	9.7
2005	60.7	10.3	0.0	0.0	4.5	0.0	213.9	5.9	8.6
2006	53.6	9.1	0.0	0.0	4.0	0.0	201.6	5.3	7.5
2007	47.3	4.8	0.0	0.0	3.5	0.0	190.0	4.7	6.6
2008	41.7	4.2	0.0	0.0	3.1	0.0	179.1	4.2	5.8
2009	36.8	3.8	0.0	0.0	2.7	0.0	168.8	3.7	5.1
2010	32.5	0.0	0.0	0.0	0.0	0.0	139.7	3.3	4.5

TABLE G.3.
PROJECTED ALASKA NORTH SLOPE OIL PRODUCTION: EXPORT CASE
(MILLION BARRELS)

	<u>PRUDHOE BAY</u>	<u>KUPARUK</u>	<u>MILNE POINT</u>	<u>LISBURN</u>	<u>ENDICOTT</u>	<u>GWYDYR BAY</u>	<u>WEST SAK</u>	<u>FLAXMAN</u>	<u>SEAL ISLAND</u>
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	27.4	0.0	0.0
1990	396.0	60.7	11.6	36.5	31.0	0.0	54.7	14.6	0.0
1991	349.4	53.9	15.5	36.5	27.3	0.0	54.7	29.2	0.0
1992	308.4	47.9	14.3	36.5	24.0	0.0	54.7	26.1	15.5
1993	272.1	42.5	8.2	31.9	21.1	0.0	54.7	23.2	31.0
1994	240.2	37.8	6.1	28.0	18.5	0.0	54.7	20.7	31.0
1995	211.9	33.5	4.5	24.5	16.3	0.0	54.7	18.5	31.0
1996	187.0	29.8	3.4	21.4	14.3	0.0	54.7	16.5	27.3
1997	165.0	26.5	2.5	18.7	12.6	0.0	54.7	14.7	24.0
1998	145.7	23.5	1.9	16.4	11.1	0.0	50.5	13.1	21.1
1999	128.5	20.9	0.0	14.4	9.7	0.0	46.7	11.7	18.5
2000	113.4	18.6	0.0	12.6	8.6	0.0	43.1	10.5	16.3
2001	100.1	16.5	0.0	11.0	7.5	0.0	39.8	9.3	14.3
2002	88.3	14.6	0.0	9.6	6.6	0.0	36.7	8.3	12.6
2003	78.0	13.0	0.0	0.0	5.8	0.0	33.9	7.4	11.1
2004	68.8	11.6	0.0	0.0	5.1	0.0	31.3	6.6	9.7
2005	60.7	6.0	0.0	0.0	4.5	0.0	28.9	5.9	8.6
2006	53.6	5.4	0.0	0.0	4.0	0.0	26.6	5.3	7.5
2007	47.3	4.8	0.0	0.0	3.5	0.0	0.0	4.7	6.6
2008	41.7	0.0	0.0	0.0	0.0	0.0	0.0	4.2	5.8
2009	36.8	0.0	0.0	0.0	0.0	0.0	0.0	3.7	5.1
2010	32.5	0.0	0.0	0.0	0.0	0.0	0.0	3.3	4.5

TABLE G.4.
PROJECTED ALASKA NORTH SLOPE OIL PRODUCTION: SEVLIMIT CASE
(MILLION BARRELS)

	<u>PRUDHOE BAY</u>	<u>KUPARUK</u>	<u>MILNE POINT</u>	<u>LISBURNE</u>	<u>ENDICOTT</u>	<u>GWYDYR BAY</u>	<u>WEST SAK</u>	<u>FLAXMAN</u>	<u>SEAL ISLAND</u>
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1987	559.9	75.8	0.0	18.3	0.0	0.0	0.0	0.0	0.0
1988	508.4	71.8	0.0	36.5	0.0	0.0	0.0	0.0	0.0
1989	448.7	68.3	0.0	36.5	0.0	0.0	0.0	0.0	0.0
1990	396.0	60.7	0.0	36.5	0.0	0.0	0.0	0.0	0.0
1991	349.4	53.9	0.0	36.5	0.0	0.0	0.0	0.0	0.0
1992	308.4	47.9	0.0	36.5	0.0	0.0	0.0	0.0	15.5
1993	272.1	42.5	0.0	31.9	0.0	0.0	0.0	0.0	31.0
1994	240.2	37.8	0.0	28.0	0.0	0.0	0.0	0.0	31.0
1995	211.9	33.5	0.0	24.5	0.0	0.0	0.0	0.0	31.0
1996	187.0	29.8	0.0	21.4	0.0	0.0	0.0	0.0	27.3
1997	165.0	26.5	0.0	18.7	0.0	0.0	0.0	0.0	24.0
1998	145.7	23.5	0.0	16.4	0.0	0.0	0.0	0.0	21.1
1999	128.5	20.9	0.0	14.4	0.0	0.0	0.0	0.0	18.5
2000	113.4	18.6	0.0	12.6	0.0	0.0	0.0	0.0	16.3
2001	100.1	16.5	0.0	11.0	0.0	0.0	0.0	0.0	14.3
2002	88.3	14.6	0.0	0.0	0.0	0.0	0.0	0.0	12.6
2003	78.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0	11.1
2004	68.8	6.8	0.0	0.0	0.0	0.0	0.0	0.0	9.7
2005	60.7	6.0	0.0	0.0	0.0	0.0	0.0	0.0	8.6
2006	53.6	5.4	0.0	0.0	0.0	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

TABLE G.5.
PROJECTED ALASKA NORTH SLOPE OIL PRODUCTION: TAXSHIFT CASE
(MILLION BARRELS)

	<u>PRUDHOE BAY</u>	<u>KUPARUK</u>	<u>MILNE POINT</u>	<u>LISBURNE</u>	<u>ENDICOTT</u>	<u>GWYDYR BAY</u>	<u>WEST SAK</u>	<u>FLAXMAN</u>	<u>SEAL ISLAND</u>
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

TABLE G.6.
CUMULATIVE OIL PRODUCTION AND DISCOUNTED VALUE, 1983-2010
LOW 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	279.643	-383.411	-922.505	315.405	1802.87
FLAXMAN	NA	NA	NA	NA	NA
KUPARUK (I)	393.11	-152.012	826.349	451.711	902.129
KUPARUK (II)	413.185	-82.68	-195.711	366.739	1573.45
LISBURNE	325.284	-113.891	-260.961	245.711	1067.92
MILNEPOINT (I)	35.543	-84.472	-204.196	47.821	296.391
MILNEPOINT (II)	46.181	-59.287	-145.506	42.264	246.339
PRUDHOE BAY	6767.72	9937.86	29418.5	10609.5	9148.88
PRUDHOE EOR	6882.09	9808.59	29188.5	10768.4	9708.66
SEAL ISLAND	297.208	-28.791	-36.854	221.201	726.879
WESTSAK1 (I)	465.374	-904.729	-2089.4	197.227	2201.27
WESTSAK2 (II)	2299.5	-4672.51	-11081.3	655.998	10846.

TABLE G.7.
CUMULATIVE OIL PRODUCTION AND DISCOUNTED VALUE, 1983-2010
HIGH 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	314.897	355.063	1142.3	864.553	1804.53
FLAXMAN	257.754	254.933	514.006	347.464	1154.92
GWYDYR	29.848	-7.743	-51.573	52.587	313.113
KUPARUK (I)	449.981	1704.4	5200.68	1280.39	903.514
KUPARUK (II)	470.056	1417.54	3342.2	1037.59	1573.7
LISBURNE	405.034	1051.96	2385.18	664.878	1070.21
MILNEPOINT (I)	52.1	84.419	289.24	176.808	300.995
MILNEPOINT (II)	55.393	57.307	203.128	133.65	248.602
PRUDHOE BAY	6767.72	27699.2	93813.3	41135.5	9148.88
PRUDHOE EOR	6882.09	27850.2	94318.1	41495.7	9708.66
SEAL ISLAND	301.71	208.993	1239.27	554.731	726.959
WESTSAK (I)	871.007	806.119	1748.83	768.269	2204.48
WESTSAK (II)	3671.54	935.417	1342.63	2353.96	10864.1

TABLE G.8.
CUMULATIVE OIL PRODUCTION AND DISCOUNTED VALUE, 1983-2010
EXPORT 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	309.147	141.812	449.802	682.349	1804.37
FLAXMAN	257.754	69.596	82.271	270.274	1154.92
KUPARUK (I)	441.996	1081.22	3733.66	1005.74	903.413
KUPARUK (II)	462.071	914.278	2156.39	815.154	1573.69
LISBURNE	389.237	654.412	1485.28	525.976	1069.9
MILNEPOINT (I)	49.571	38.794	118.267	134.518	300.244
MILNEPOINT (II)	53.986	28.823	84.185	103.389	248.233
PRUDHOE BAY	6767.72	24091.8	72348.4	26520.7	9148.88
PRUDHOE EOR	6882.09	24143.8	72608.1	26825.4	9708.66
SEAL ISLAND	301.71	175.095	814.086	443.806	726.959
WESTSAK (I)	802.743	189.767	392.758	586.147	2204.3
WESTSAK (II)	3671.54	-1022.47	-2897.39	1842.46	10864.1

TABLE G.9.
CUMULATIVE OIL PRODUCTION AND DISCOUNTED VALUE, 1983-2010
HIGH CASE WITH WINDFALL PROFITS TAX
(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	314.897	355.063	1142.3	864.553	1804.53
FLAXMAN	257.754	254.933	514.006	347.464	1154.92
KUPARUK (I)	449.981	1704.4	5200.68	1280.39	903.514
KUPARUK (II)	470.056	1417.54	3342.2	1037.59	1573.7
LISBURNE	405.034	1051.96	2385.18	664.878	1070.21
MILNEPOINT (I)	52.1	84.419	289.24	176.808	300.995
MILNEPOINT (II)	55.393	57.307	203.128	133.65	248.602
PRUDHOE BAY	6767.72	26128.7	93813.3	44157.4	9148.88
PRUDHOE EOR	6882.09	26287.8	94318.1	44502.	9708.66
SEAL ISLAND	301.71	208.993	1239.27	554.731	726.959
WESTSAK (I)	871.007	806.119	1748.83	768.269	2204.48
WESTSAK (II)	3671.54	935.417	1342.63	2353.96	10864.1

TABLE G.10.
CUMULATIVE OIL PRODUCTION AND DISCOUNTED VALUE, 1983-2010
EXPORT CASE WITH WINDFALL PROFITS TAX
(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	309.147	141.812	449.802	682.349	1804.37
FLAXMAN	257.754	69.596	82.271	270.274	1154.92
KUPARUK (I)	441.996	1081.22	3733.66	1005.74	903.413
KUPARUK (II)	462.071	914.278	2156.39	815.154	1573.69
LISBURNE	389.237	654.412	1485.28	525.976	1069.9
MILNEPOINT (I)	49.571	38.794	118.267	134.518	300.244
MILNEPOINT (II)	53.986	28.823	84.185	103.389	248.233
PRUDHOE BAY	6767.72	23539.6	72348.4	27583.2	9148.88
PRUDHOE EOR	6882.09	23594.4	72608.1	27882.5	9708.66
SEAL ISLAND	301.71	175.095	814.086	443.806	726.959
WESTSAK (I)	802.743	189.767	392.758	586.147	2204.3
WESTSAK (II)	3671.54	-1022.47	-2897.39	1842.46	10864.1

TABLE G.11.
CUMULATIVE OIL PRODUCTION AND DISCOUNTED VALUE, 1983-2010
SEVERANCE TAX LIMIT 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	-11.989	104.64	631.427	1804.25
FLAXMAN	250.668	-40.644	-133.84	265.129	1154.76
KUPARUK (I)	437.236	720.541	3002.4	963.573	903.339
KUPARUK (II)	457.311	623.461	1565.17	779.721	1573.67
LISBURNE	379.611	387.122	1039.67	591.818	1069.68
MILNEPOINT (I)	49.571	-5.316	36.628	136.913	300.244
MILNEPOINT (II)	52.1	-0.043	24.844	99.1	247.756
PRUDHOE BAY	6767.72	23774.	61616.2	16359.8	9148.88
PRUDHOE EOR	6882.09	23828.1	61753.6	16537.4	9708.66
SEAL ISLAND	301.71	144.747	601.495	414.766	726.959
WESTSAK (I)	747.231	-234.633	-273.061	727.824	2204.08
WESTSAK (II)	3671.54	-2000.25	-5017.4	1586.71	10864.1

TABLE G.12.
CUMULATIVE OIL PRODUCTION AND DISCOUNTED VALUE, 1983-2010
TAXSHIFT 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	32.692	104.64	559.36	1804.25
FLAXMAN	250.668	-7.473	-133.84	213.63	1154.76
KUPARUK (I)	437.236	753.454	3002.4	793.604	903.339
KUPARUK (II)	457.311	659.717	1565.17	644.203	1573.67
LISBURNE	379.611	449.892	1039.67	427.969	1069.68
MILNEPOINT (I)	49.571	8.369	36.628	113.165	300.244
MILNEPOINT (II)	52.1	8.518	24.844	84.482	247.756
PRUDHOE BAY	6767.72	22526.3	61616.2	16086.8	9148.88
PRUDHOE EOR	6882.09	22559.2	61753.6	16305.6	9708.66
SEAL ISLAND	301.71	139.706	601.495	367.306	726.959
WESTSAK (I)	747.231	-94.501	-273.061	489.226	2204.08
WESTSAK (II)	3671.54	-1841.04	-5017.4	1586.71	10864.1

Impact of Tax Simplification Proposals on Oil and Gas Production and the Economy

ALASKA



INTERSTATE OIL COMPACT COMMISSION

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Joint Chairmen

W. TIMOTHY DOWD
Executive Director

February 27, 1985

MEMORANDUM

TO: Governors, Official Representatives, and Members
of the Interstate Oil Compact Commission

FROM: W. Timothy Dowd

The attached report explains the effects of the tax simplification proposals on oil and gas production and the economics of the various producing states. This includes an analysis of the impact of the proposal on your state. Its focus is upon the impact of the repeal of expensing of intangible drilling costs and on the proposals as they relate to enhanced oil recovery projects.

This effort represents a preliminary report, and is subject to revision. Should there be any suggestions to be made as to format or content, please write me.

MEMBER STATES: ALABAMA • ALASKA • ARIZONA • ARKANSAS • CALIFORNIA • COLORADO • FLORIDA • ILLINOIS • INDIANA • KANSAS • KENTUCKY
LOUISIANA • MARYLAND • MICHIGAN • MISSISSIPPI • MONTANA • NEBRASKA • NEVADA • NEW MEXICO • NEW YORK • NORTH DAKOTA • OHIO
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Executive Summary

This report presents the findings of a three-part study initiated by the Interstate Oil Compact Commission ("IOCC") to determine the economic impact on the United States and on each IOCC member state of changes in federal tax laws recently proposed by the Treasury Department.

The IOCC is an organization of thirty petroleum producing states concerned with the conservation of oil and gas through waste prevention at the production level. An IOCC task force commissioned The RAM Group, Ltd., an Oklahoma City management consulting firm, to conduct the study.

This report is divided into two parts. Part One presents the results of the study for an individual IOCC member state and Part Two presents the national findings. Each part is divided into three sections, covering the economic impact of:

- repealing the expensing of intangible drilling costs;
- removal of percentage depletion on stripper oil wells;
- federal tax proposals on enhanced oil recovery.

The study concludes that the Treasury Department's tax proposals would cause a dramatic drop in domestic oil and natural gas drilling, production, proven reserves, and enhanced oil recovery projects, thereby greatly increasing the nation's reliance on imported oil. Moreover, the reduced activity in the petroleum industry would have a severe economic impact not only in oil and gas producing states but on the entire nation. For example, the study forecasts that repealing the expensing of intangible drilling costs would result in the loss of more than a half million jobs in the petroleum and other industries; would reduce annual drilling expenditures by more than \$11.2 billion, and would reduce domestic additions of oil and natural gas reserves by the equivalent of more than 5.6 billion barrels of oil.

IMPACT ON THE NATIONAL ECONOMY OF REPEALING THE EXPENSING OF INTANGIBLE DRILLING COSTS

Introduction

This study examines the impact on Alaska's economy of repealing the expensing of intangible drilling costs. Under current tax law, intangible drilling costs (IDC's) are defined as expenditures that in themselves do not have salvage value and are incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and natural gas. Examples of intangible drilling costs include wages, fuel and other supplies used in preparing to drill wells, and in drilling and completing wells. In contrast, the costs of steel tubular goods, valves and other equipment with salvage value are considered tangible equipment and must be capitalized for tax purposes.

Currently, intangible drilling costs may be deducted in calculating taxable income for the year in which they are incurred. However, under a recent proposal by the Treasury Department, intangible drilling costs would be capitalized, thus requiring the tax deductions for these expenditures to be spread out over the productive life of the well. Under this proposal, which, if enacted, would be effective for costs paid or incurred on or after January 1, 1986, the effect would be to greatly reduce the amount of cash available for drilling.

Major Findings

The study found that repealing the expensing of intangible drilling costs would have the following results, on average, during the 1986-91 period:

- drilling expenditures would be reduced by \$293,918,643 annually;
- 14,696 jobs would be lost due to reduced drilling;
- 82 fewer oil and gas wells would be drilled each year;
- drilling rigs operating would be reduced by 6 yearly;
- additions to domestic oil and natural gas reserves would be reduced 146,967,100 barrels of oil equivalent (oil and natural gas, where one barrel of oil is the energy equivalent of 5,800 cubic feet of gas) during the six year period;
- daily oil and natural gas production would fall by 19,855 barrels of oil equivalent;

- annual revenues from oil and gas sales would fall by \$142,249,055;
- state tax receipts from oil and gas production would fall by \$17,419,087 annually.

Background on Expensing IDC's

Under current law, oil and gas producers have the right to elect to expense IDC's as incurred or to capitalize them. They may also elect to expense only the IDC's on dry wells and to capitalize the IDC's on productive wells. If capitalized, the costs are recovered through depletion and depreciation. No investment tax credit is allowed for IDC expenditures.

Normally, oil and gas producers elect to expense IDC's in the year occurred, as this increases their after-tax cash flow. Because of the time value of money, a tax benefit allowed in year one is obviously worth more than the same tax benefit spread out over several years.

Impact on After-Tax Cash Flow

Tables One through Five calculate the total tax benefits allowed for drilling a typical well at a total cost of \$590,000 under current law and under four proposed changes in the current law. This total expenditure consists of \$400,000 spent on IDC's; \$140,000 spent on equipment and depreciated over a ten year period; and, \$50,000 spent on leasehold and depleted over the same ten year period. Note that on Table One, Current Law, the tax rate is 50% and IDC's are deducted in year one. Table Two shows that under the Kemp-Kasten proposal, the tax rate is reduced to 25%, but IDC deductions are spread over a three year period. Table Three shows that the Bradley-Gephardt proposal sets the tax rate at 30%, but requires IDC expenditures to be depreciated over the productive life of the well, in this case assumed to be ten years. Table Four, Treasury Proposal Without Indexing, sets the tax rate at 35% and treats IDC's the same as the Bradley-Gephardt proposal. Table Five, Treasury Proposal Including Indexing at 6% Annual Rate of Inflation, shows the same tax rate and treatment for IDC's as in Table Four, except the cost basis is adjusted each year for inflation, thus increasing the amount of the deductions allowed in years two through ten.

Compared to present law, each of the four proposed changes would reduce the tax benefits available to the producer in year one. Although most of the tax benefits in years two through ten would be somewhat higher under the four proposed changes, these increases would not be enough to restore the tax benefits available in year one under current law.

Table Six, Evaluation and Dollar Comparison of Total Tax Benefits Under the Various Flat Tax Proposals, summarizes the total tax benefits as calculated in Tables One through Five and compares the tax benefits, in dollars, of the current law to those that would be available under the four proposed changes. Note that in year one the producer's tax benefits are reduced by \$192,100 to \$200,300 under the four proposed changes, so the lower overall tax rates do not offset the reduced IDC deductions.

Table Seven, Evaluation and Percentage Comparison of Total Tax Benefits Under the Various Flat Tax Proposals, uses the same total tax benefit data discussed above, and shows the percentage reduction in current tax benefits under each of the four proposed changes. Note that in year one, the total tax benefit from a \$590,000 drilling expenditure drops by more than 32% in each case.

Table Eight, Evaluation and Comparison of After-Tax Cash Flow Using the Total Tax Benefits Under the Various Flat Tax Proposals, assumes a producer has \$590,000 of income which he uses to drill a well. The drilling expenditure generates various tax deductions under the current law and the four proposed changes, resulting in the after-tax cash flow shown in Table Eight. The largest reduction, \$103,600 or 17.56%, occurs in year one under the Treasury proposal, with or without inflation indexing. Even though the Producer's cash flow would be increased by 4.32% in year two under the Treasury proposal with indexing, his tax benefits for new expenditure made that year would once again be 17.56% lower than under current law. So, under the Treasury proposal, the after-tax cash flow of the producer who drills new wells each year would never catch up with the amount he could expect under current law.

Impact on Alaska Economy

The impact on the Alaska economy of repealing the expensing of intangible drilling costs is assessed by taking the effect on the producer's after tax cash flow from an average well, as analyzed above, and applying the results to overall petroleum industry figures.

Table Nine, Alaska Analysis of the Impact of the Proposed Tax Treatment on Intangible Drilling Costs on Drilling Expenditures, Wells Drilled, Employment and Reserves Found - 1986-1991, shows the historical expenditures for domestic drilling for 1980 through 1983, as reported by the Joint Association Survey. Under current law, 1986-91 drilling expenditures are forecast to remain at the 1983 level. Presently, approximately 38% of the funds available for drilling is obtained from outside the petroleum industry from sources such as investors and bank loans. Approximately 62% of the funds available for drilling is generated within the industry from oil and gas revenues.

For an investor, the ability to expense two-thirds or more of his investment in oil and gas drilling during the first year is a major incentive for putting his dollars at risk. Falling oil and natural gas prices during the past two years have already made it more difficult to raise outside capital, through either debt or equity means. If a worthwhile yet high risk investment has no better tax treatment than a safe investment, the investor may as well play it safe. Thus, third party funding is forecast to drop by one-half in 1986 under the Treasury proposal.

The economic analysis forecasts that, if the Treasury proposal were enacted, drilling expenditures in 1986 would drop \$261,000,000. The reduction would be due to uncertainty within the industry and reduced funding from outside investors and lenders. After 1986, industry expenditures on domestic drilling are forecast to remain at 1984 levels, adjusted by the percentage change in after-tax cash flow, as calculated on Table Eight for the Treasury proposal.

Economic research has found that a reduction in drilling expenditures of \$1,000,000 results in the loss of fifty jobs. Therefore, the 1986-1991 yearly average of \$293,918,643 in reduced drilling expenditures would result in 14,696 jobs lost.

At an average cost of \$371,721 per well, these reduced drilling expenditures would mean that 82 fewer oil and gas wells would be drilled each year, and 6 fewer rigs would be running annually. Based on an average finding cost of \$12 per barrel of oil equivalent, reserve additions would be reduced by 146,967,100 barrels of oil equivalent during the six year period.

Because of the reduced drilling, daily production would drop by an average of 19,855 barrels of oil equivalent. At an average price of \$19.63 per barrel of oil equivalent, the reduced production would result in an average annual reduction in oil and gas sales of \$142,249,055. Revenues from state production taxes, at an average tax rate of 8% would drop \$17,419,087 annually.

The impact on the Alaska economy is illustrated by Charts One through Seven, each headed Alaska Impact of IDC Tax Proposal. Chart One, Comparison of Drilling Expenditures Yearly, shows historical drilling expenditures from 1980 through 1984, then compares the forecast of domestic drilling expenditures under current law to the forecast for expenditures under the Treasury Proposal. The remaining charts show the 1986-1991 annual impact on drilling expenditures, employment, wells drilled, rigs in operation, reserves added, and daily production.

Tax Benefits From Drilling Expenditures Available Under
Current Law

Table One

Year	IDC	Depreciation	Depletion	Total Deductions	Tax Benefit At 50% Rate	Investment Tax Credit	Total Tax Benefits
1	400,000	21,000	7,800	428,800	214,400	11,200	225,600
2	0	30,800	11,700	42,500	21,300	0	21,300
3	0	29,400	8,300	37,700	18,900	0	18,900
4	0	29,400	7,300	36,700	18,400	0	18,400
5	0	29,400	6,300	35,700	17,900	0	17,900
6	0	0	4,700	4,700	2,400	0	2,400
7	0	0	2,200	2,200	1,100	0	1,100
8	0	0	1,100	1,100	600	0	600
9	0	0	400	400	200	0	200
10	0	0	200	200	100	0	100
TOTAL	400,000	140,000	50,000	590,000	295,300	11,200	306,500
Net After Tax Present Value at						12.00%	255,800

IDC =	\$400,000
Equipment =	\$140,000
Leasehold =	\$50,000
Total Expenditures =	\$590,000
Tax Return =	50.00%

Keep - Kasten Proposal

Table Two

Year	IDC	Depreciation	Depletion	Total Deductions	Tax Benefit At 25% Rate	Investment Tax Credit	Total Tax Benefits
1	100,000	21,000	12,500	133,500	33,400	0	33,400
2	152,000	30,800	19,000	201,800	50,500	0	50,500
3	148,000	29,400	18,500	195,900	49,000	0	49,000
4	0	29,400	0	29,400	7,400	0	7,400
5	0	29,400	0	29,400	7,400	0	7,400
6	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0
TOTAL	400,000	140,000	50,000	590,000	147,700	0	147,700
Net After Tax Present Value at						12.00%	113,900

IDC = \$400,000
 Equipment = \$140,000
 Leasehold = \$50,000
 Total Expenditures = \$590,000
 Tax Return = 25.00%

Bradley - Gephardt Proposal

Table Th

Year	IDC	Depreciation	Depletion	Total Deductions	Tax Benefit At 30% Rate	Investment Tax Credit	Total Tax Benefits
1	50,000	28,000	6,300	84,300	25,300	0	25,300
2	87,500	44,800	10,900	143,200	43,000	0	43,000
3	65,600	26,900	8,200	100,700	30,200	0	30,200
4	49,200	16,100	6,200	71,500	21,500	0	21,500
5	36,900	9,700	4,600	51,200	15,400	0	15,400
6	27,700	5,800	3,500	37,000	11,100	0	11,100
7	20,800	3,500	2,600	26,900	8,100	0	8,100
8	15,600	2,100	1,900	19,600	5,900	0	5,900
9	11,700	1,200	1,500	14,400	4,300	0	4,300
10	35,000	1,900	4,300	41,200	12,400	0	12,400
TOTAL	400,000	140,000	50,000	590,000	177,200	0	177,200
Net After Tax Present Value at						12.00%	118,000

IDC = \$400,000
 Equipment = \$140,000
 Leasehold = \$50,000
 Total Expenditures = \$590,000
 Tax Return = 30.00%

Treasury Proposal Without Indexing

Table Four

Year	IDC	Depreciation	Depletion	Total Deductions	Tax Benefit At 35% Rate	Investment Tax Credit	Total Tax Benefits
1	62,600	25,200	7,800	95,600	22,500	0	33,500
2	93,900	20,700	11,700	126,300	44,200	0	44,200
3	66,100	16,900	8,300	91,300	32,000	0	32,000
4	58,400	13,900	7,300	79,600	27,900	0	27,900
5	50,100	11,400	6,300	67,800	23,700	0	23,700
6	37,600	9,300	4,700	51,600	18,100	0	18,100
7	17,400	7,700	2,200	27,300	9,700	0	9,600
8	8,700	6,300	1,100	16,100	5,600	0	5,600
9	3,500	5,100	400	9,000	3,200	0	3,200
10	1,700	23,500	200	25,400	8,900	0	8,900
TOTAL	400,000	140,000	50,000	590,000	195,800	0	206,700
Net After Tax Present Value at						12.00%	138,900

IDC = \$400,000
 Equipment = \$140,000
 Leasehold = \$50,000
 Total Expenditures = \$590,000
 Tax Return = 35.00%

Treasury Proposal Including Indexing
At 6% Annual Rate of Inflation

Table Five

Year	IDC	Depreciation	Depletion	Total Deductions	Tax Benefit At 35% Rate	Investment Tax Credit	Total Tax Benefits
1	62,600	25,200	7,800	95,600	33,500	0	33,500
2	99,500	21,900	12,400	133,800	46,800	0	46,800
3	74,300	19,000	9,300	102,600	35,900	0	35,900
4	69,600	16,500	8,700	94,800	33,200	0	33,200
5	63,200	14,400	7,900	85,500	29,900	0	29,900
6	50,300	12,500	6,300	69,100	24,200	0	24,200
7	24,700	10,900	3,100	38,700	13,500	0	13,500
8	13,100	9,400	1,600	24,100	8,400	0	8,400
9	5,500	8,200	700	14,400	5,000	0	5,000
10	2,900	39,600	400	42,900	15,000	0	15,000
TOTAL	465,700	177,600	58,200	701,500	245,400	0	245,400

Net After Tax Present Value at 12.00% 159,200

IDC = \$400,000
 Equipment = \$140,000
 Leasehold = \$50,000
 Total Expenditures = \$590,000
 Tax Return = 35.00%

Table Six

EVALUATION AND DOLLAR COMPARISON
OF TOTAL TAX BENEFITS UNDER
THE VARIOUS FLAT TAX PROPOSALS

TOTAL TAX BENEFIT					COMPARISON OF TAX BENEFITS WITH CURRENT LAW				
YEAR	CURRENT LAW 50%	KEMP & KASTEN 25%	BRADLEY & GEPHEARDT 30%	TREASURY WITHOUT INDEXING 35%	TREASURY WITH INDEXING 35%	KEMP & KASTEN 25%	BRADLEY & GEPHEARDT 30%	TREASURY WITHOUT INDEXING 35%	TREASURY WITH INDEXING 35%
1	\$225,600	\$33,400	\$25,300	\$33,500	\$33,500	(\$192,200)	(\$200,300)	(\$192,100)	(\$192,100)
2	\$21,300	\$50,500	\$43,000	\$44,200	\$46,800	\$29,200	\$21,700	\$22,900	\$25,500
3	\$18,900	\$49,000	\$30,200	\$32,000	\$35,900	\$30,100	\$11,300	\$13,100	\$17,000
4	\$19,400	\$7,400	\$21,500	\$27,900	\$33,200	(\$11,000)	\$3,100	\$9,500	\$14,800
5	\$17,900	\$7,400	\$15,400	\$23,700	\$29,900	(\$10,500)	(\$2,500)	\$5,800	\$12,000
6	\$2,400	\$0	\$11,100	\$18,100	\$24,200	(\$2,400)	\$8,700	\$15,700	\$21,800
7	\$1,100	\$0	\$8,100	\$9,600	\$13,500	(\$1,100)	\$7,000	\$8,500	\$12,400
8	\$600	\$0	\$5,900	\$5,600	\$8,400	(\$600)	\$5,300	\$5,000	\$7,800
9	\$200	\$0	\$4,300	\$3,200	\$5,000	(\$200)	\$4,100	\$3,000	\$4,800
10	\$100	\$0	\$12,400	\$8,900	\$15,000	(\$100)	\$12,300	\$8,800	\$14,900
TOTAL	\$306,500	\$147,700	\$177,200	\$206,700	\$245,400	(\$158,800)	(\$129,300)	(\$99,800)	(\$61,100)
NPV @									
12.00%	\$255,772	\$113,859	\$117,980	\$138,896	\$159,230	(\$141,913)	(\$137,792)	(\$116,876)	(\$96,542)

BASIS:

IDC: \$400,000
EQUIPMENT: \$140,000
LEASEHOLD: \$50,000

*** ASSUMING 6% INFLATION INDEXING IN YEARS 2 THROUGH 10.

Table Seven

EVALUATION AND PERCENTAGE COMPARISON
OF TOTAL TAX BENEFITS UNDER
THE VARIOUS FLAT TAX PROPOSALS

YEAR	TOTAL TAX BENEFIT					PERCENT REDUCTION IN TAX BENEFIT BASED ON A \$590,000 EXPENDITURE IN YEAR 1			
	CURRENT LAW 50%	KEMP & KASTEN 25%	BRADLEY & GEPHEARDT 30%	TREASURY WITHOUT INDEXING 35%	TREASURY WITH INDEXING*** 35%	KEMP & KASTEN 25%	BRADLEY & GEPHEARDT 30%	TREASURY WITHOUT INDEXING 35%	TREASURY WITH INDEXING*** 35%
1	\$225,600	\$33,400	\$25,300	\$33,500	\$33,500	-32.58%	-33.95%	-32.56%	-32.56%
2	\$21,300	\$50,500	\$43,000	\$44,200	\$46,800	4.95%	3.68%	3.88%	4.32%
3	\$18,900	\$49,000	\$30,200	\$32,000	\$35,900	5.10%	1.92%	2.22%	2.88%
4	\$18,400	\$7,400	\$21,500	\$27,900	\$33,200	-1.86%	0.53%	1.61%	2.51%
5	\$17,900	\$7,400	\$15,400	\$23,700	\$29,900	-1.78%	-0.42%	0.98%	2.03%
6	\$2,400	\$0	\$11,100	\$18,100	\$24,200	-0.41%	1.47%	2.66%	3.69%
7	\$1,100	\$0	\$8,100	\$9,600	\$13,500	-0.19%	1.19%	1.44%	2.10%
8	\$600	\$0	\$5,900	\$5,600	\$8,400	-0.10%	0.90%	0.85%	1.32%
9	\$200	\$0	\$4,300	\$3,200	\$5,000	-0.03%	0.69%	0.51%	0.81%
10	\$100	\$0	\$12,400	\$8,900	\$15,000	-0.02%	2.08%	1.49%	2.53%
TOTAL	\$306,500	\$147,700	\$177,200	\$206,700	\$245,400	-26.92%	-21.92%	-16.92%	-10.36%

NPV @

12.00% \$255,772 \$113,859 \$117,980 \$138,896 \$155,230

BASIS:

IDC: \$400,000

EQUIPMENT: \$140,000

LEASEHOLD: \$50,000

TOTAL \$590,000

*** ASSUMING 6% INFLATION INDEXING IN YEARS 2 THROUGH 10.

Table Eight

EVALUATION AND COMPARISON
OF AFTER TAX CASH FLOW USING
THE IDC TOTAL TAX BENEFITS UNDER
THE VARIOUS FLAT TAX PROPOSALS

EFFECT ON AFTER TAX CASH FLOW****						PERCENT REDUCTION IN CASH AVAILABLE TO SPEND BASED ON \$590,000 EXPENDITURE IN YEAR 1			
YEAR	CURRENT LAW 50%	KEMP & KASTEN 25%	BRADLEY & GEPHEARDT 30%	TREASURY	TREASURY	KEMP & KASTEN 25%	BRADLEY & GEPHEARDT 30%	TREASURY	TREASURY
				WITHOUT INDEXING 35%	WITH INDEXING*** 35%			WITHOUT INDEXING 35%	WITH INDEXING*** 35%
1	\$520,600	\$475,900	\$438,300	\$417,000	\$417,000	-7.58%	-13.95%	-17.56%	-17.56%
2	\$21,300	\$50,500	\$43,000	\$44,200	\$46,800	4.95%	3.68%	3.88%	4.32%
3	\$18,900	\$49,000	\$30,200	\$32,000	\$35,900	5.10%	1.92%	2.22%	2.88%
4	\$18,400	\$7,400	\$21,500	\$27,900	\$33,200	-1.86%	0.53%	1.61%	2.51%
5	\$17,900	\$7,400	\$15,400	\$23,700	\$29,900	-1.78%	-0.42%	0.96%	2.03%
6	\$2,400	\$0	\$11,100	\$18,100	\$24,200	-0.41%	1.47%	2.66%	3.69%
7	\$1,100	\$0	\$8,100	\$9,600	\$13,500	-0.19%	1.19%	1.44%	2.10%
8	\$600	\$0	\$5,900	\$5,600	\$6,400	-0.10%	0.90%	0.85%	1.32%
9	\$200	\$0	\$4,300	\$3,200	\$5,000	-0.03%	0.69%	0.51%	0.81%
10	\$100	\$0	\$12,400	\$8,900	\$15,000	-0.02%	2.08%	1.49%	2.53%
TOTAL	601500	590200	590200	590200	628900	-1.92%	-1.92%	-1.92%	4.64%

NOTE:

**** AFTER TAX CASH FLOW TAKING INTO ACCOUNT IDC AND OTHER TAX BENEFITS (AS CALCULATED ON TABLES ONE THROUGH FIVE).

*** ASSUMING 6% INFLATION INDEXING IN YEARS 2 THROUGH 10.

** TAX WITHOUT TAKING INTO ACCOUNT IDC TAX BENEFITS.

* AFTER TAX CASH FLOW WITHOUT TAKING INTO ACCOUNT IDC TAX BENEFITS.

BASIS:

IDC: \$400,000

EQUIPMENT: \$140,000

LEASEHOLD: \$50,000

TOTAL \$590,000

IDCMASTER

ALASKA
ANALYSIS OF THE IMPACT OF THE PROPOSED TAX TREATMENT
OF INTANGIBLE DRILLING COSTS ON DRILLING EXPENDITURES,
WELLS DRILLED, EMPLOYMENT & RESERVES FOUND - 1986- 1991

1984 DRILLING RIGS 14
1983 WELL COST \$3,576,143
GPT TAX RATE 12.50%

YEAR	CURRENT LAW		TREASURY PROPOSAL		REDUCTION IN TOTAL CASH AVAILABLE FOR DRILLING (\$mm)	REDUCTION IN DRILLING EXPENDITURES (\$mm)	REDUCTION IN EMPLOYMENT (JOBS)	REDUCTION IN TOTAL WELLS DRILLED	REDUCTION IN DRILLING RIG ACTIVITY	REDUCTION IN RESERVES ADDED (mmBOE)	REDUCTION IN DAILY PRODUCTION (BOE/DAY)
	TOTAL CASH AVAILABLE FOR DRILLING (\$mm)	J.A.S. DRILLING EXPENDITURES (\$mm)	TOTAL CASH AVAILABLE FOR DRILLING (\$mm)	J.A.S. DRILLING EXPENDITURES (\$mm)							
80	\$551	\$551	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
81	\$673	\$673	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
82	\$817	\$817	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
83	\$658	\$658	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
84	\$658	\$658	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
86	\$658	\$658	\$397	\$397	\$261	\$261	13,028	73	6	22	2,082
87	\$658	\$658	\$328	\$328	\$330	\$330	16,517	92	7	28	8,589
88	\$658	\$658	\$357	\$357	\$301	\$301	15,040	84	6	25	17,382
89	\$658	\$658	\$360	\$360	\$298	\$298	14,880	83	6	25	24,920
90	\$658	\$658	\$367	\$367	\$291	\$291	14,532	81	6	24	30,677
91	\$658	\$658	\$374	\$374	\$284	\$284	14,176	79	6	24	35,478
TOTAL	\$3,948	\$3,948	\$2,185	\$2,185	\$1,763	\$1,763	n.a.	493	n.a.	147	n.a.
AVERAGE	\$658	\$658	\$364	\$364	\$294	\$294	14,696	82	6	24	19,855

AVERAGE IMPACT 1986-91:

REDUCTION IN DRILLING EXPENDITURES YEARLY
REDUCTION IN EMPLOYMENT DUE TO REDUCED DRILLING:
REDUCTION IN NUMBER OF WELLS DRILLED YEARLY
REDUCTION IN DRILLING RIG RUNNING YEARLY
REDUCTION IN RESERVES ADDED AT \$12.00 PER BOE:
REDUCTION IN DAILY OIL AND GAS PRODUCTION:
REDUCTION IN OIL AND GAS SALES:
REDUCTION IN STATE GPT COLLECTIONS:

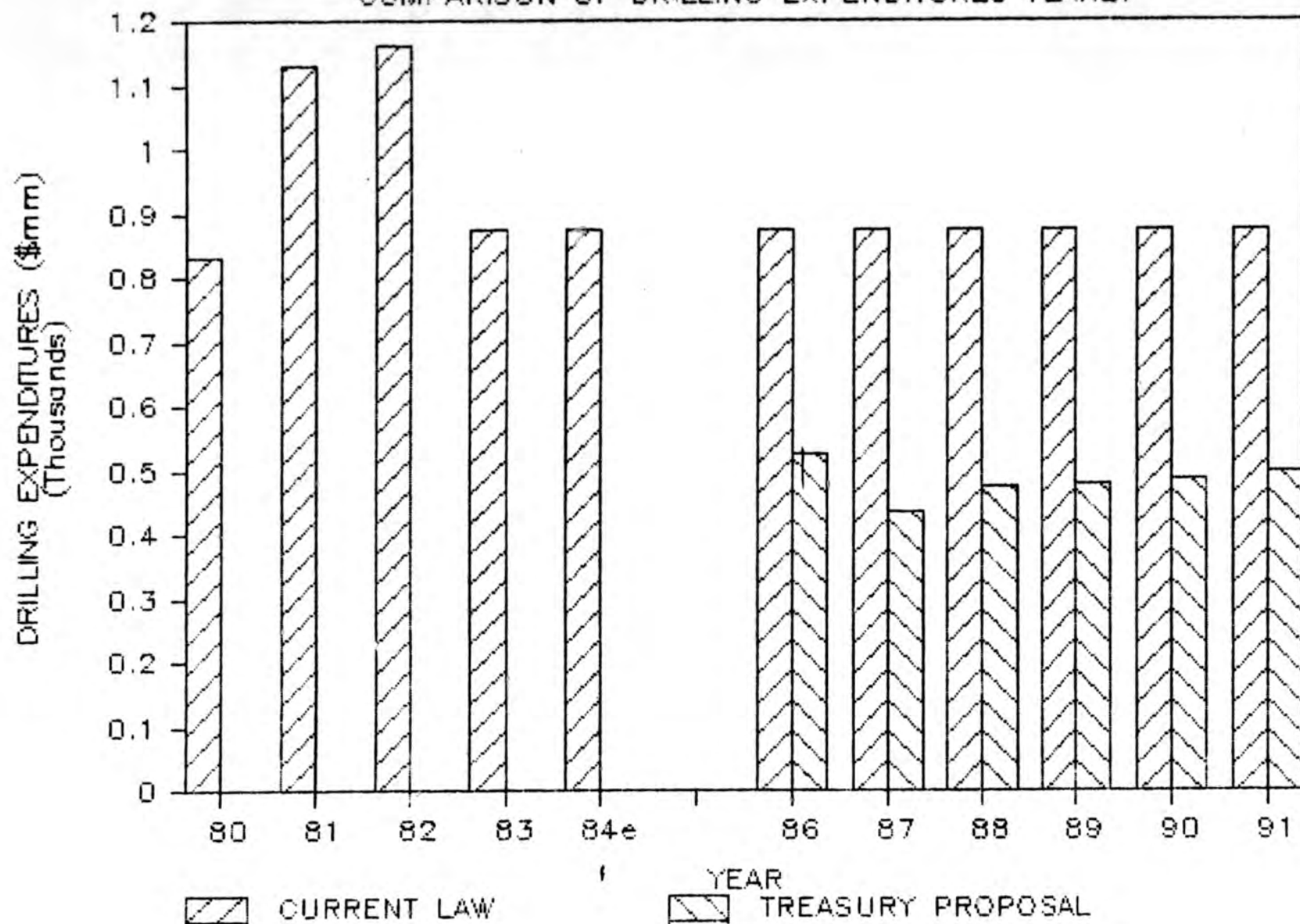
\$294 MILLION
14,696 JOBS
82 WELLS
6 RIGS
147 mmBOE
19,855 BOE/DAY
\$142 MILLION
\$18 MILLION

ASSUMPTIONS:

INDUSTRY EXPENDITURES ARE REDUCED BY ONE-THIRD IN 1986 DUE TO UNCERTAINTY AND REDUCED THIRD PARTY FUNDING
THIRD PARTY FUNDING IS REDUCED BY ONE-HALF IN 1986 DUE TO UNCERTAINTY IN TAX TREATMENT
AFTER 1986 INDUSTRY EXPENDITURES REMAIN AT TWO-THIRDS OF 1984 LEVELS + OR - REDUCED CASH FLOW FROM ACCELERATED TAX PAYMENTS.
AFTER 1986 THIRD PARTY FUNDING REMAIN AT ONE-HALF OF 1984 LEVELS + OR - REDUCED CASH FLOW FROM ACCELERATED TAX PAYMENTS.
1986 AVERAGE WELLHEAD PRICE WAS \$19.63/BOE.
A REDUCTION IN DRILLING EXPENDITURES OF ONE MILLION DOLLARS RESULTS IN A LOSS OF 50 JOBS.

AP IMPACT OF IDC TAX PROPOSAL

COMPARISON OF DRILLING EXPENDITURES YEARLY



AP IMPACT OF IDC TAX PROPOSAL

REDUCTION IN DRILLING EXPENDITURES YEARLY

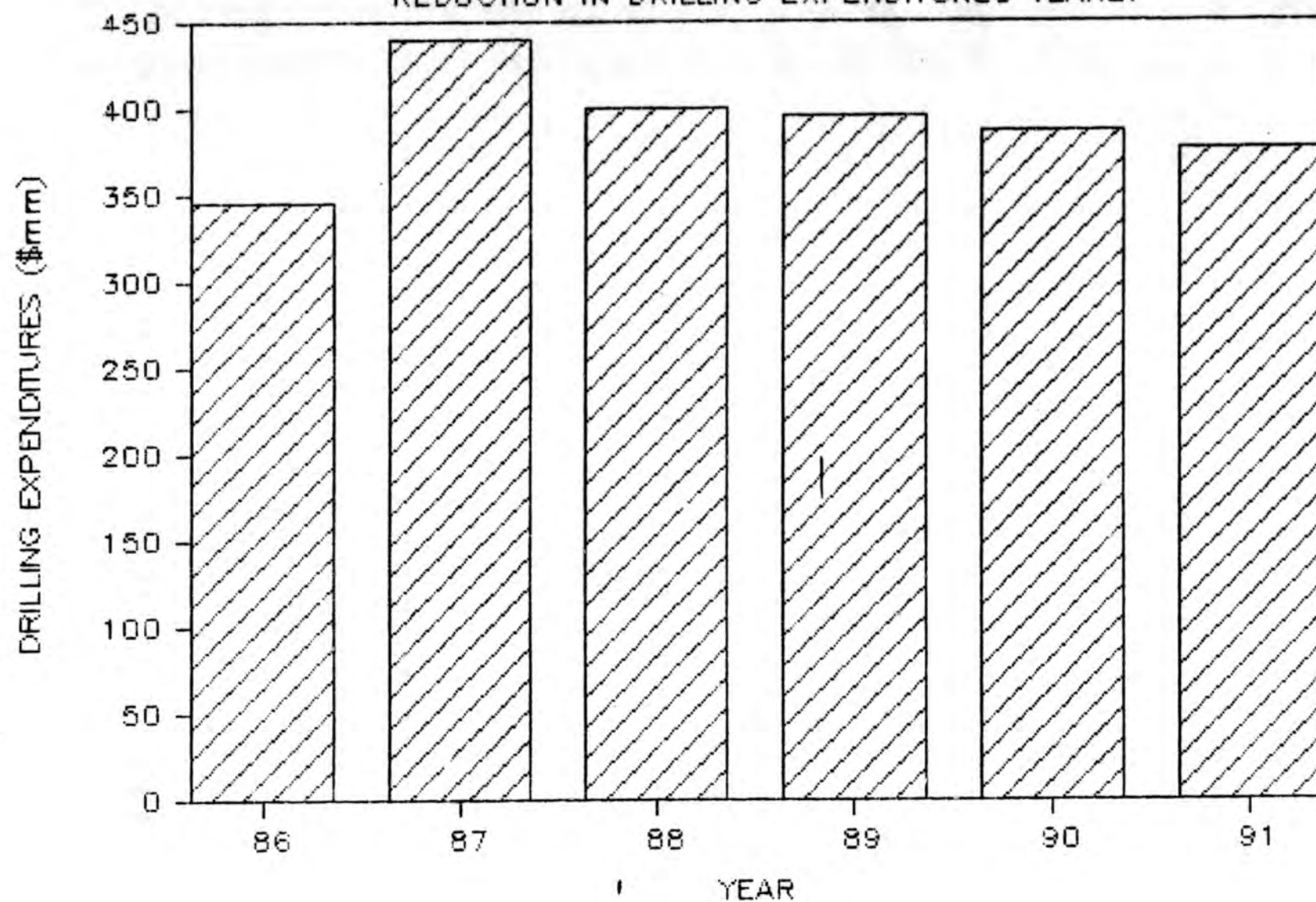


CHART TWO

AP IMPACT OF IDC TAX PROPOSAL

REDUCTION IN EMPLOYMENT DUE TO REDUCED DRILLING:

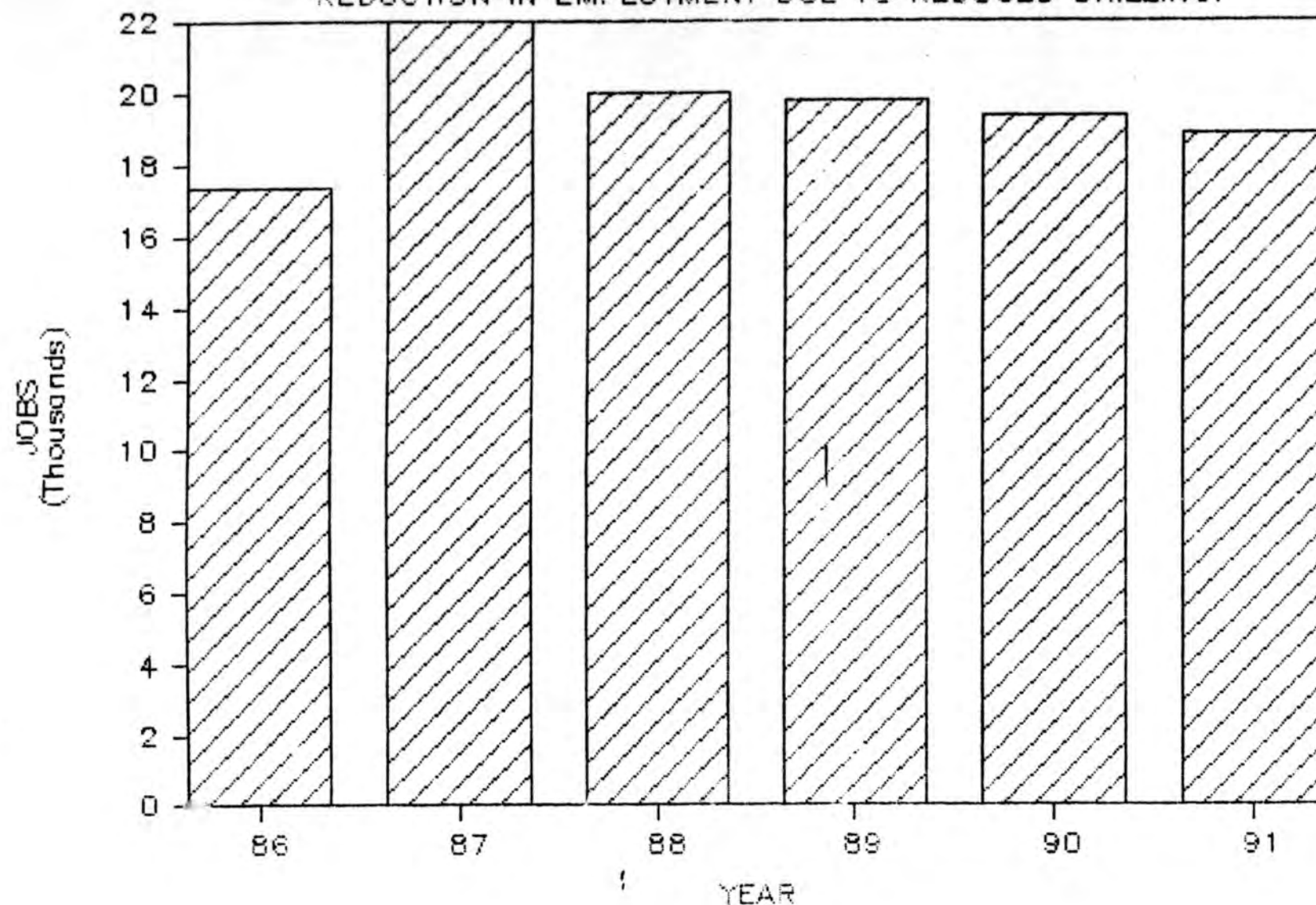
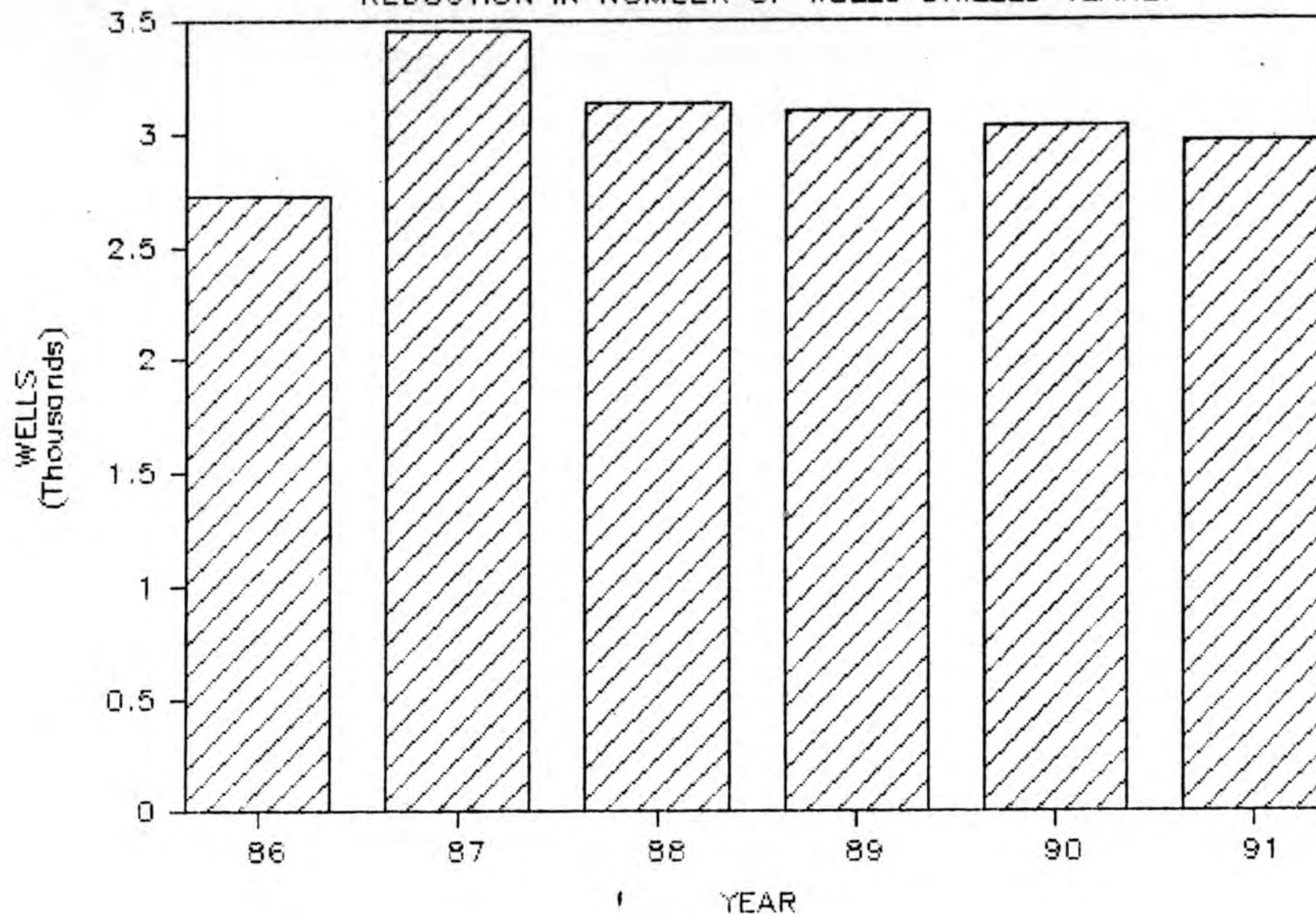


CHART THREE

AP IMPACT OF IDC TAX PROPOSAL

REDUCTION IN NUMBER OF WELLS DRILLED YEARLY



AP IMPACT OF IDC TAX PROPOSAL

REDUCTION IN DRILLING RIG RUNNING YEARLY

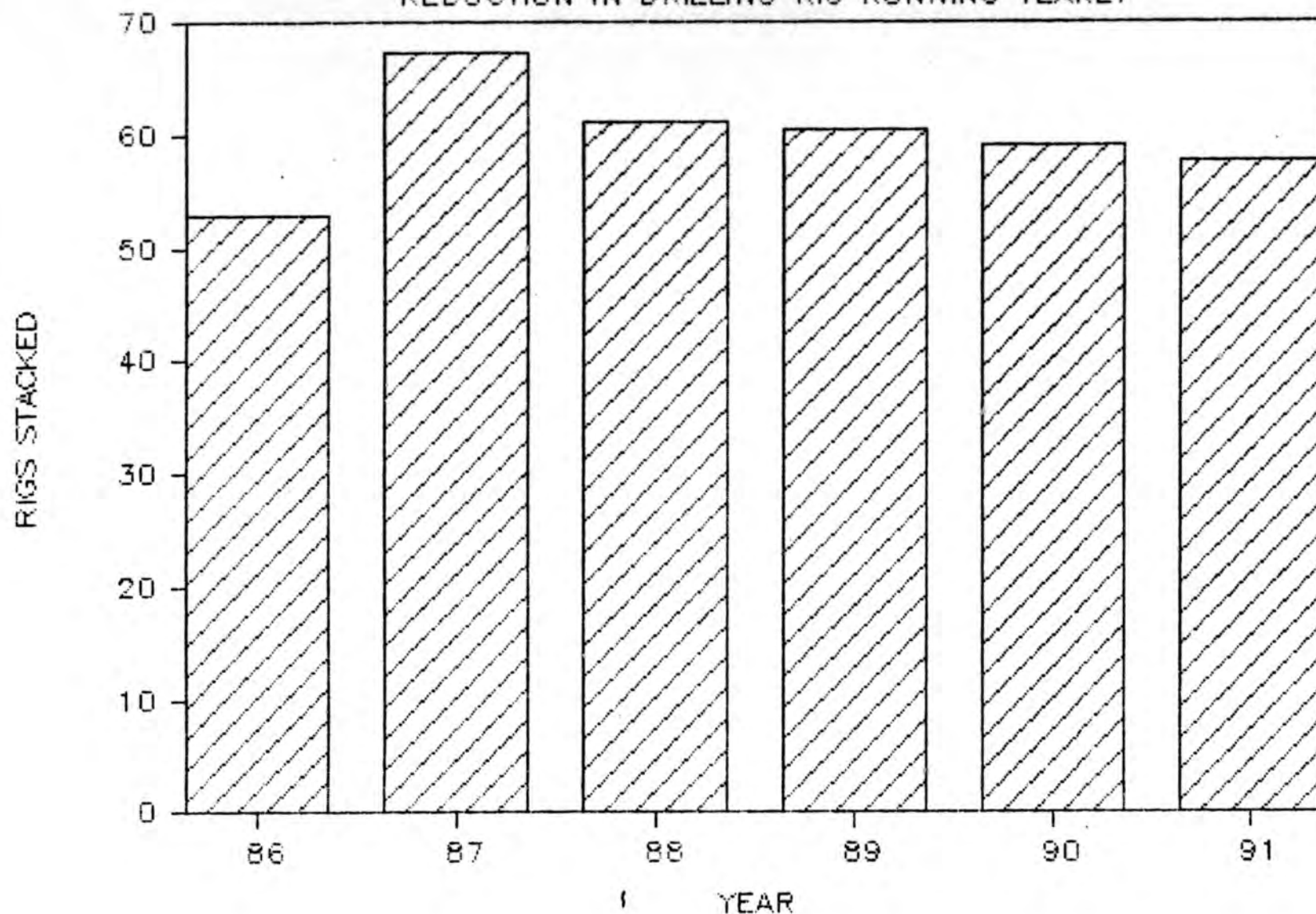
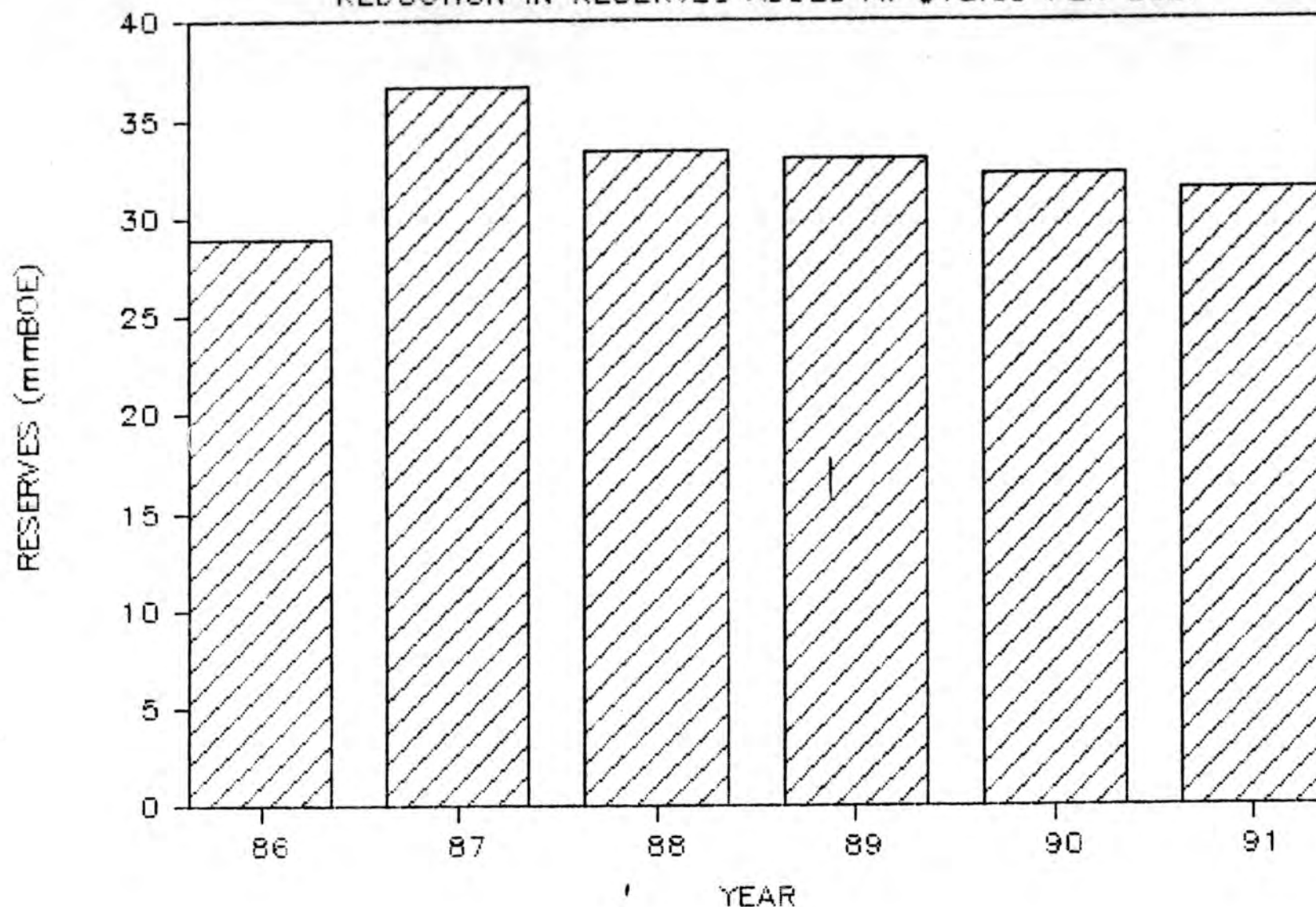


CHART FIVE

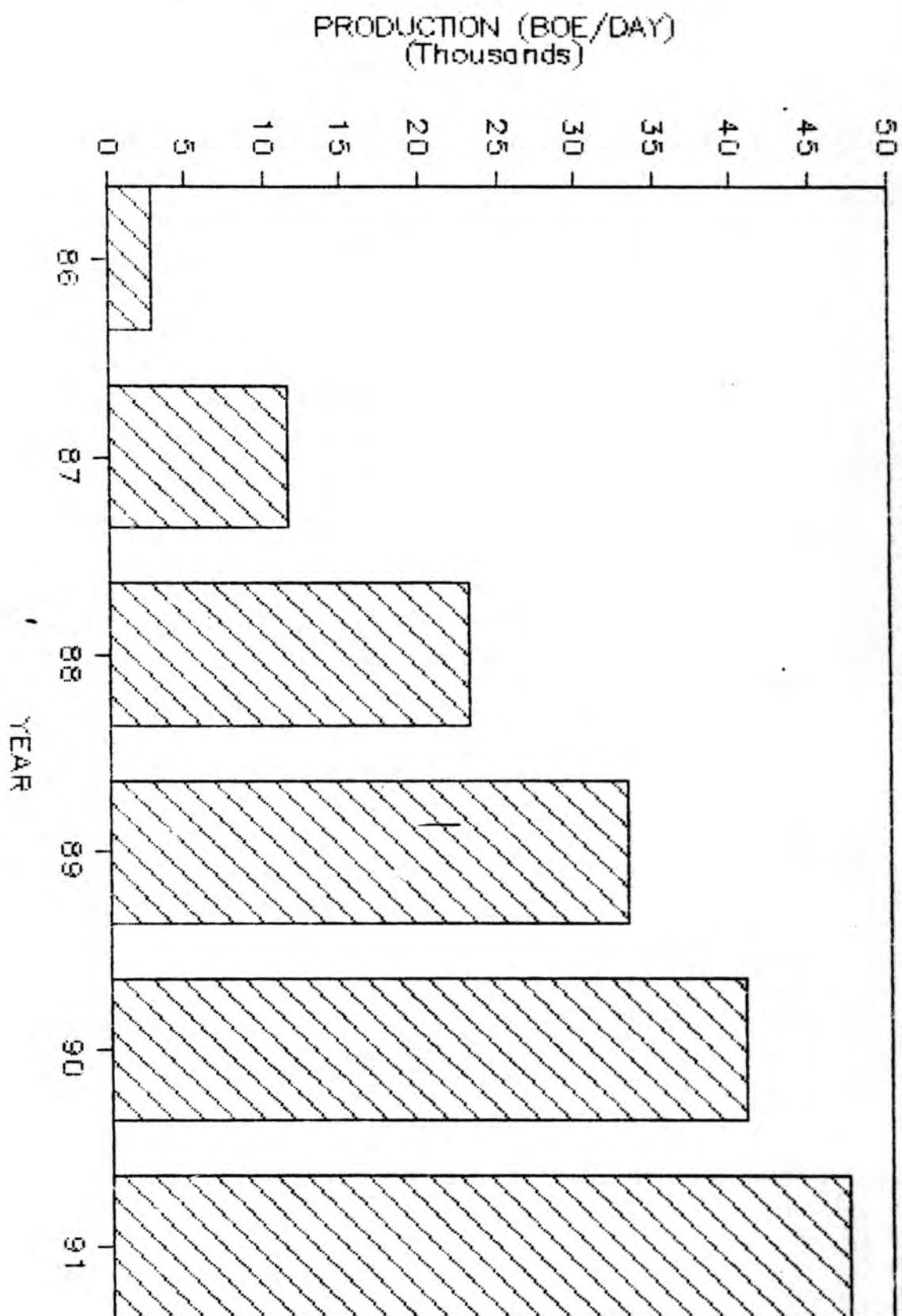
AP IMPACT OF IDC TAX PROPOSAL

REDUCTION IN RESERVES ADDED AT \$12.00 PER BOE:



AP IMPACT OF IDC TAX PROPOSAL

REDUCTION IN DAILY OIL AND GAS PRODUCTION:



IMPACT OF FEDERAL TAX PROPOSALS ON ENHANCED OIL RECOVERY

Introduction

The purpose of this study is to forecast the impact of the Treasury Department's recent tax proposals on ongoing and projected enhanced oil recovery ("EOR") operations.

Enhanced oil recovery is the incremental oil that can be economically produced from a petroleum reservoir over that which can be economically recovered by conventional primary and secondary production methods. Primary methods rely on the natural reservoir energy to drive the oil through reservoir rock to producing wells. Over time, this natural energy drive dissipates, and energy must be added to the reservoir to produce significant amounts of additional oil.

Conventional secondary recovery methods introduce additional energy through the injection of water or gas, under pressure, into the formation at substantial additional costs. Enhanced oil recovery techniques are employed to achieve further production after primary and secondary recovery has been exhausted. Examples of enhanced oil recovery methods include: chemical flooding, miscible flooding, injection of carbon dioxide and thermal recovery.

Existing EOR projects currently account for 6% of U.S. daily oil production. The resource to which enhanced oil recovery may be applied in the future is very large, because conventional primary and secondary methods are expected to recover only about one-third of the oil originally discovered. Although much of the remaining two-thirds of the oil originally-in-place is not producible, a significant portion of this remaining resource constitutes the target for EOR.

Oil production by enhanced recovery is more costly than production by most conventional methods. Because of these high costs and heavy front-end investments required for most EOR projects, tax policies which reduce the after-tax cash flow available to producers will result in significant reductions in the number of projects undertaken and thus, the amount of oil recovered. Moreover, tax policies which hasten the abandonment of marginally economic fields remove the reserves remaining in the fields as potential resources for enhanced recovery.

The Treasury Department's recent tax proposals would effect several tax provisions that currently encourage EOR projects. These proposals would change depreciation schedules and repeal the following tax provisions: percentage depletion; the expensing on intangible drilling costs; the deduction of

qualified tertiary injectant expenses; and, the investment tax credit. Although the Treasury Department proposal would also lower the marginal tax rate and repeal the Windfall Profit Tax, these favorable changes would be more than offset by the increased taxes resulting from the other changes described above.

Major Findings

The study found that the Treasury Department's tax proposals would have a significant negative impact on EOR projects. The reduced after-tax cash flow available to producers under the Treasury tax proposal would effect enhanced oil recovery in Alaska in the years ahead as follows:

- oil production from EOR projects would be reduced by 94 million barrels;
- royalty payments would drop by \$184,000,000;
- property and severance tax payments would fall by \$8,000,000;
- state income tax collections would be reduced by \$66,000,000;
- federal income tax collections from third parties would increase \$220,000,000;
- reductions in payments to suppliers of good and services would equal \$1,404,000,000;
- equipment purchases would fall by \$14,000,000;
- intangible drilling costs for EOR wells would decrease by \$8,000,000

Basis for Projections

These projections are based on an EOR data base and economic model developed by the Bartlesville Energy Center, and on "Enhanced Oil Recovery," a report by the National Petroleum Council to the Secretary of Energy, dated June 21, 1984.

IMPACT OF FEDERAL TAX PROPOSALS ON ENHANCED OIL RECOVERY (EOR)

	NATIONALLY	ALASKA
REDUCTION IN EOR PRODUCTION	1,832	94 (MMBBL)
REDUCTION IN ROYALTY PAYMENTS	10,351	184 (MM \$)
REDUCTION IN PROPERTY AND SEVERENCE TAX PAYMENTS	2,228	8 (MM \$)
REDUCTION IN STATE INCOME TAX COLLECTIONS	635	66 (MM \$)
REDUCTION IN FEDERAL INCOME TAX COLLECTIONS	1,313	(220) (MM \$)
REDUCTION IN PAYMENTS TO THIRD PARTIES	34,174	1,404 (MM \$)
REDUCTION IN EQUIPMENT PURCHASES	2,250	14 (MM \$)
REDUCTION IN IDC'S FOR EOR WELLS	896	8 (MM \$)

NOTE: All impacts are cumulative.

Basis:

- National Petroleum Council Enhanced Oil Recovery, June 21, 1984 Bartlesville Energy Center EOR Data Base And Economic Model State By State.
- Actual state by state current property and severence tax rates.
- Actual state by state income tax rates.
- Provisions of Treasury Secretary Regan's November 27, 1984 tax proposal regarding:
 - Intangible investments
 - Tertiary injectants
 - Revised ACRS depreciation
 - No tax credit
 - Modified depreciation schedules
 - Crude oil price of \$30.00 per barrel
 - 10% rate of return on investment

IDCEFFECT

NATIONAL
ANALYSIS OF THE IMPACT OF THE PROPOSED TAX TREATMENT
OF INTANGIBLE DRILLING COSTS ON DRILLING EXPENDITURES,
WELLS DRILLED, EMPLOYMENT & RESERVES FOUND - 1986- 1991

1984 DRILLING RIGS 2248
1983 WELL COST \$371,721
GPT TAX RATE 6.00%

YEAR	CURRENT LAW		TREASURY PROPOSAL		REDUCTION IN TOTAL CASH AVAILABLE FOR DRILLING (\$mm)		REDUCTION IN EMPLOYMENT (JOBS)	REDUCTION IN TOTAL WELLS DRILLED	REDUCTION IN DRILLING RIG ACTIVITY	REDUCTION IN RESERVES ADDED (mmBOE)	REDUCTION IN DAILY PRODUCTION (BOE/DAY)
	TOTAL CASH AVAILABLE FOR DRILLING (\$mm)	J.A.S. DRILLING EXPENDITURES (\$mm)	TOTAL CASH AVAILABLE FOR DRILLING (\$mm)	J.A.S. DRILLING EXPENDITURES (\$mm)							
80	\$22,800	\$22,800	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
81	\$36,665	\$36,665	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
82	\$39,428	\$39,428	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
83	\$25,105	\$25,105	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
84	\$25,105	\$25,105	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
86	\$25,105	\$25,105	\$15,163	\$15,163	\$9,941	\$9,941	497,066	26,744	890	828	79,440
87	\$25,105	\$25,105	\$10,308	\$10,308	\$14,797	\$14,797	739,827	39,805	1,325	1,233	345,208
88	\$25,105	\$25,105	\$12,508	\$12,508	\$12,596	\$12,596	629,820	33,887	1,128	1,050	722,190
89	\$25,105	\$25,105	\$12,026	\$12,026	\$13,079	\$13,079	653,927	35,184	1,171	1,090	1,052,693
90	\$25,105	\$25,105	\$12,393	\$12,393	\$12,712	\$12,712	635,592	34,197	1,138	1,059	1,307,298
91	\$25,105	\$25,105	\$12,576	\$12,576	\$12,529	\$12,529	626,425	33,704	1,122	1,044	1,522,928
TOTAL	\$150,627	\$150,627	\$74,974	\$74,974	\$75,653	\$75,653	n.a.	203,521	n.a.	6,304	n.a.
AVERAGE	\$25,105	\$25,105	\$12,496	\$12,496	\$12,609	\$12,609	630,443	33,920	1,129	1,051	838,293

AVERAGE IMPACT 1986-91:

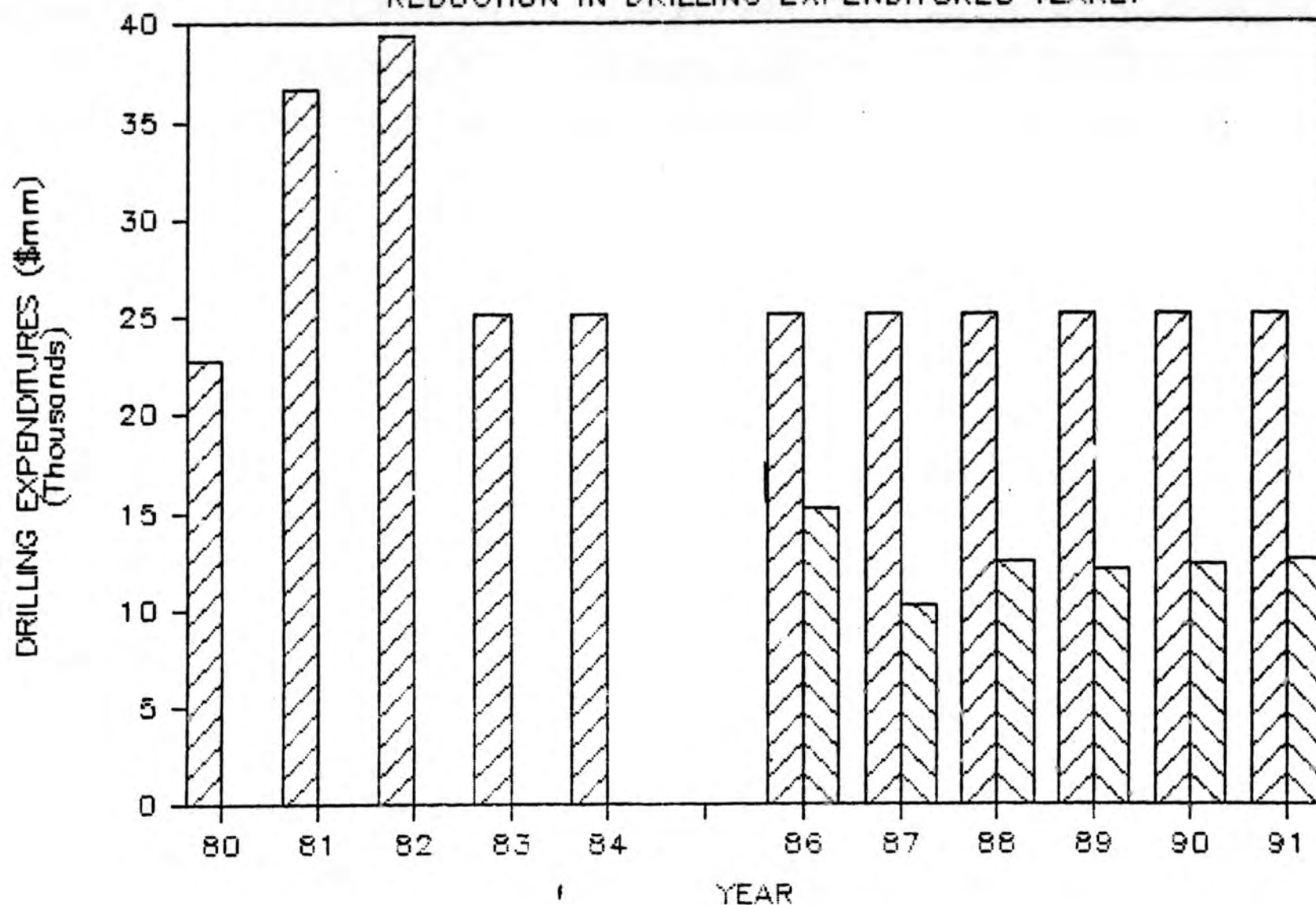
REDUCTION IN DRILLING EXPENDITURES YEARLY	\$12,609 MILLION
REDUCTION IN EMPLOYMENT DUE TO REDUCED DRILLING:	630,443 JOBS
REDUCTION IN NUMBER OF WELLS DRILLED YEARLY	33,920 WELLS
REDUCTION IN DRILLING RIG RUNNING YEARLY	1,129 RIGS
REDUCTION IN RESERVES ADDED AT \$12.00 PER BOE:	6,304 mmBOE
REDUCTION IN DAILY OIL AND GAS PRODUCTION:	838,293 BOE/DAY
REDUCTION IN OIL AND GAS SALES:	\$6,006 MILLION
REDUCTION IN STATE GPT COLLECTIONS:	\$360 MILLION

ASSUMPTIONS:

INDUSTRY EXPENDITURES ARE REDUCED BY ONE-THIRD IN 1986 DUE TO UNCERTAINTY AND REDUCED THIRD PARTY FUNDING
THIRD PARTY FUNDING IS REDUCED BY ONE-HALF IN 1986 DUE TO UNCERTAINTY IN TAX TREATMENT
AFTER 1986 INDUSTRY EXPENDITURES REMAIN AT TWO-THIRDS OF 1984 LEVELS + OR - REDUCED CASH FLOW FROM ACCELERATED TAX PAYMENTS.
AFTER 1986 THIRD PARTY FUNDING REMAIN AT ONE-HALF OF 1984 LEVELS + OR - REDUCED CASH FLOW FROM ACCELERATED TAX PAYMENTS.
1986 AVERAGE WELLHEAD PRICE WAS \$19.63/BOE.
A REDUCTION IN DRILLING EXPENDITURES OF ONE MILLION DOLLARS RESULTS IN A LOSS OF 50 JOBS.

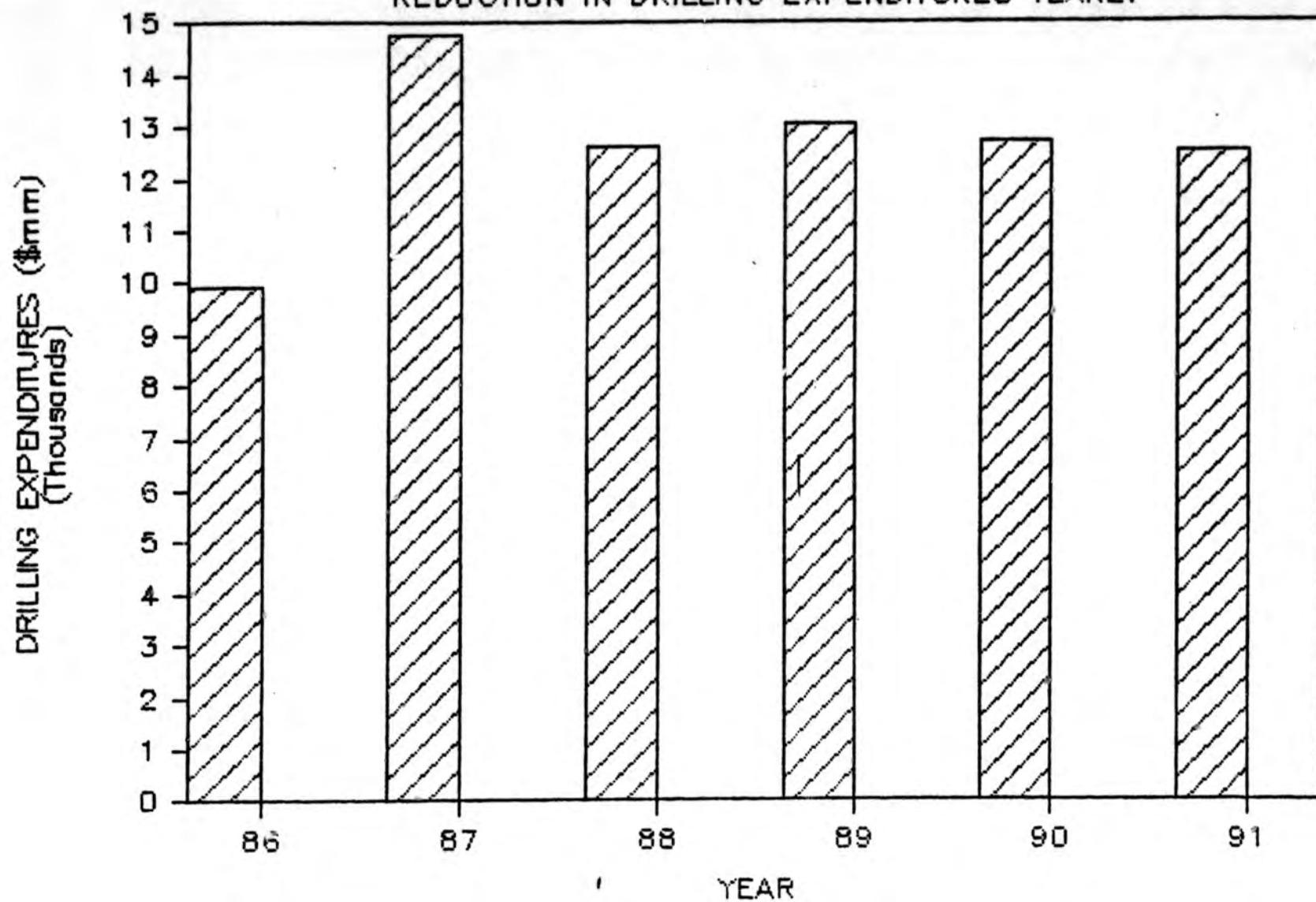
U.S. IMPACT OF IDC TAX PROPOSAL

REDUCTION IN DRILLING EXPENDITURES YEARLY



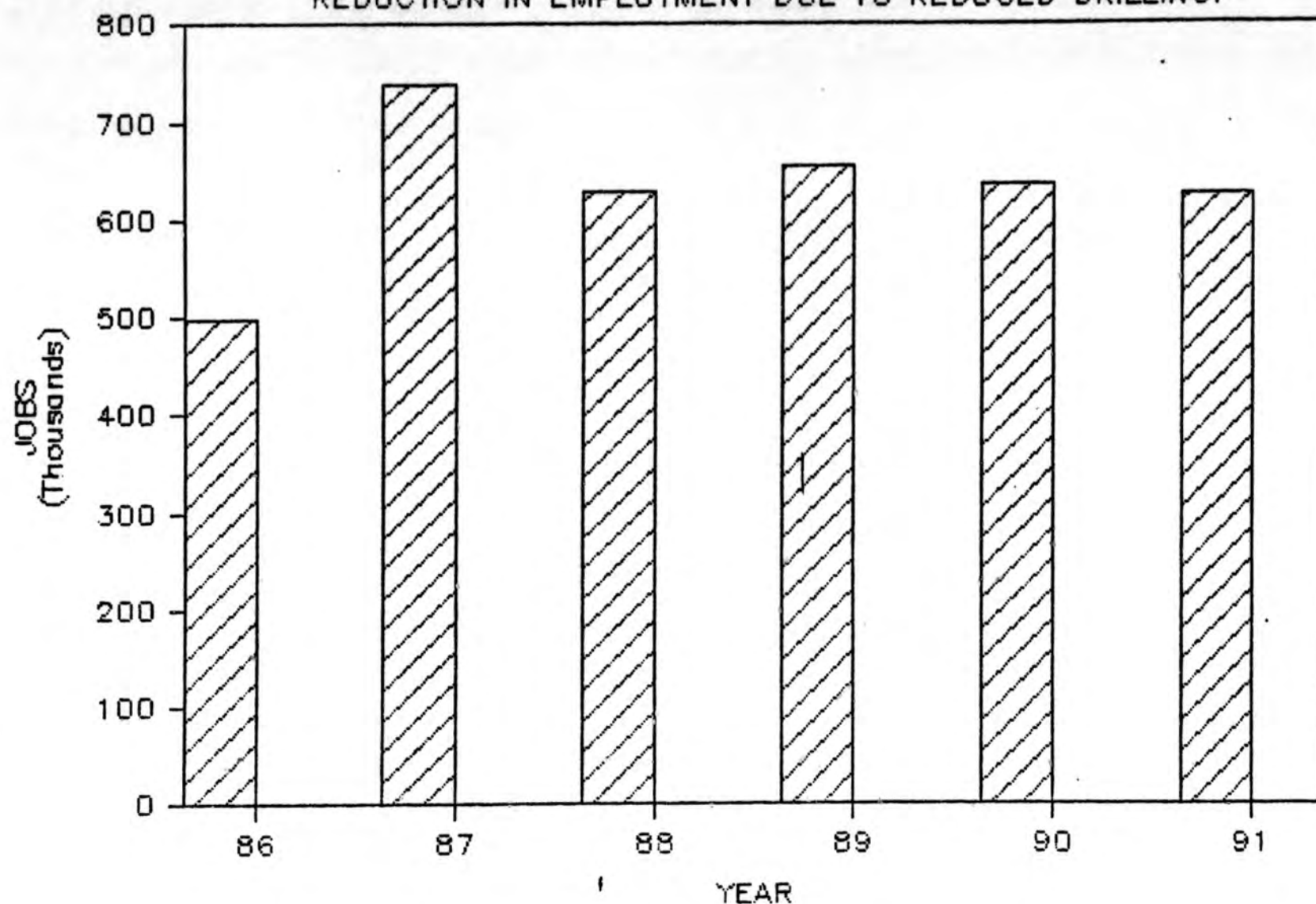
U.S. IMPACT OF IDC TAX PROPOSAL

REDUCTION IN DRILLING EXPENDITURES YEARLY



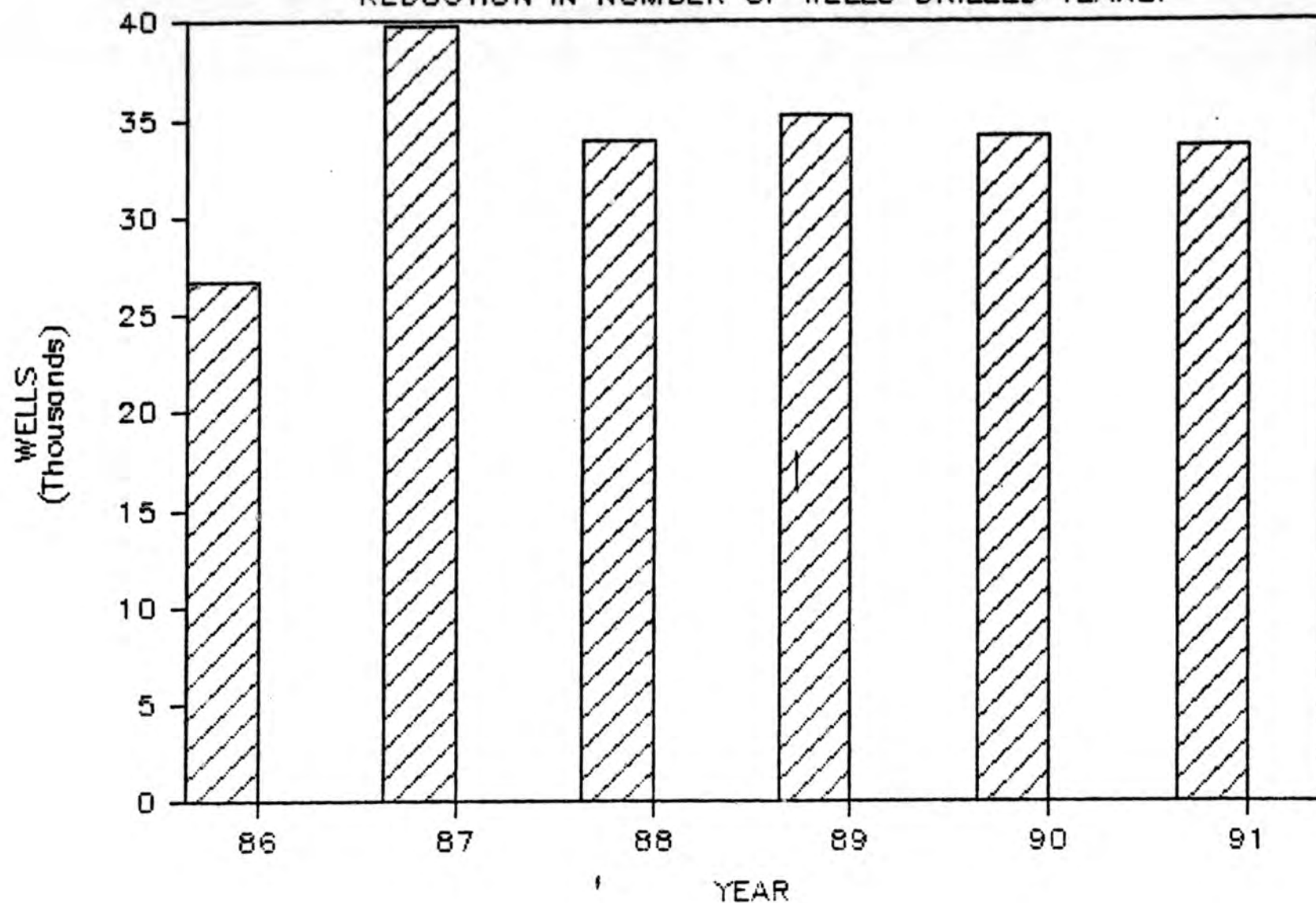
U.S. IMPACT OF IDC TAX PROPOSAL

REDUCTION IN EMPLOYMENT DUE TO REDUCED DRILLING:



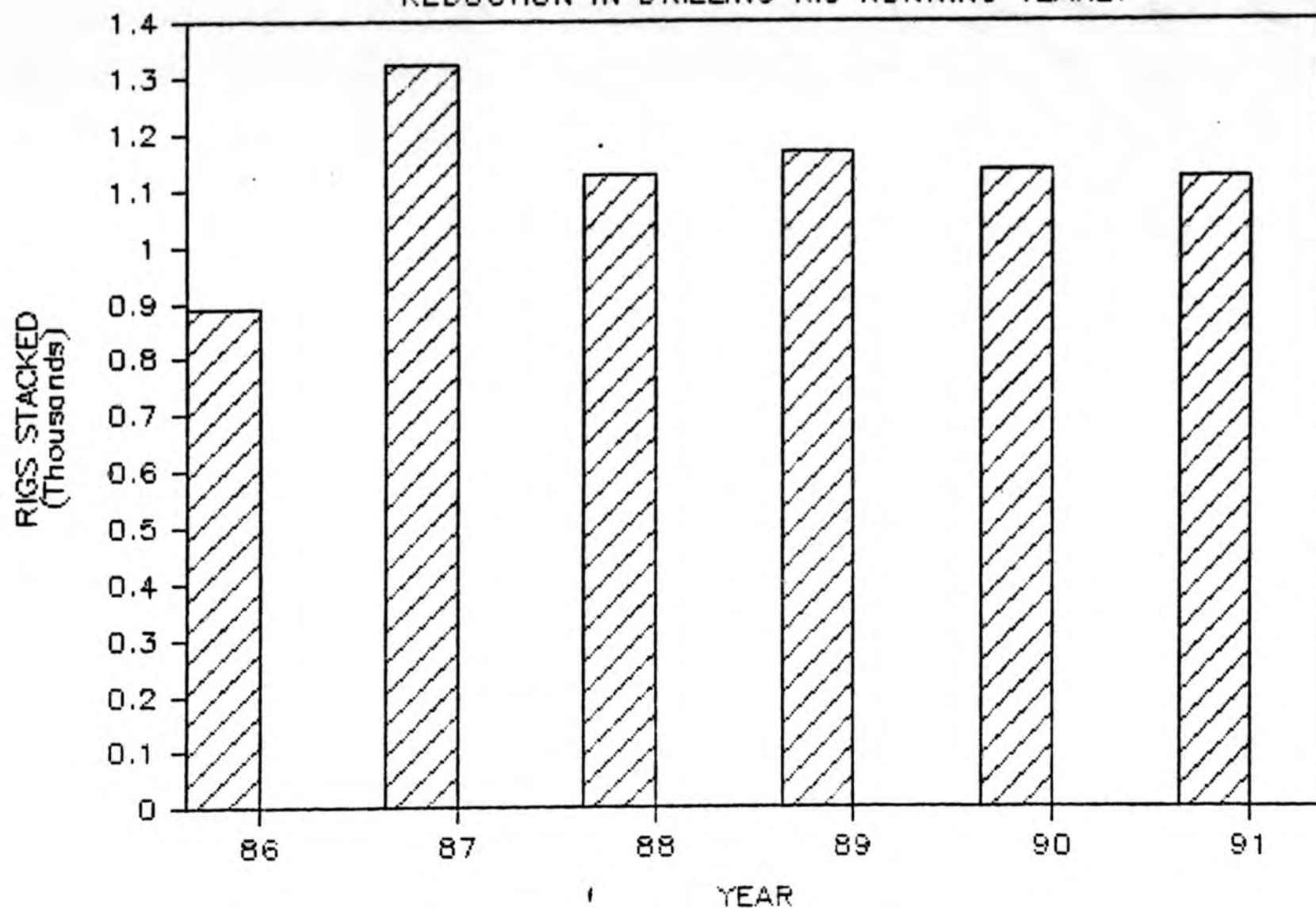
U.S. IMPACT OF IDC TAX PROPOSAL

REDUCTION IN NUMBER OF WELLS DRILLED YEARLY



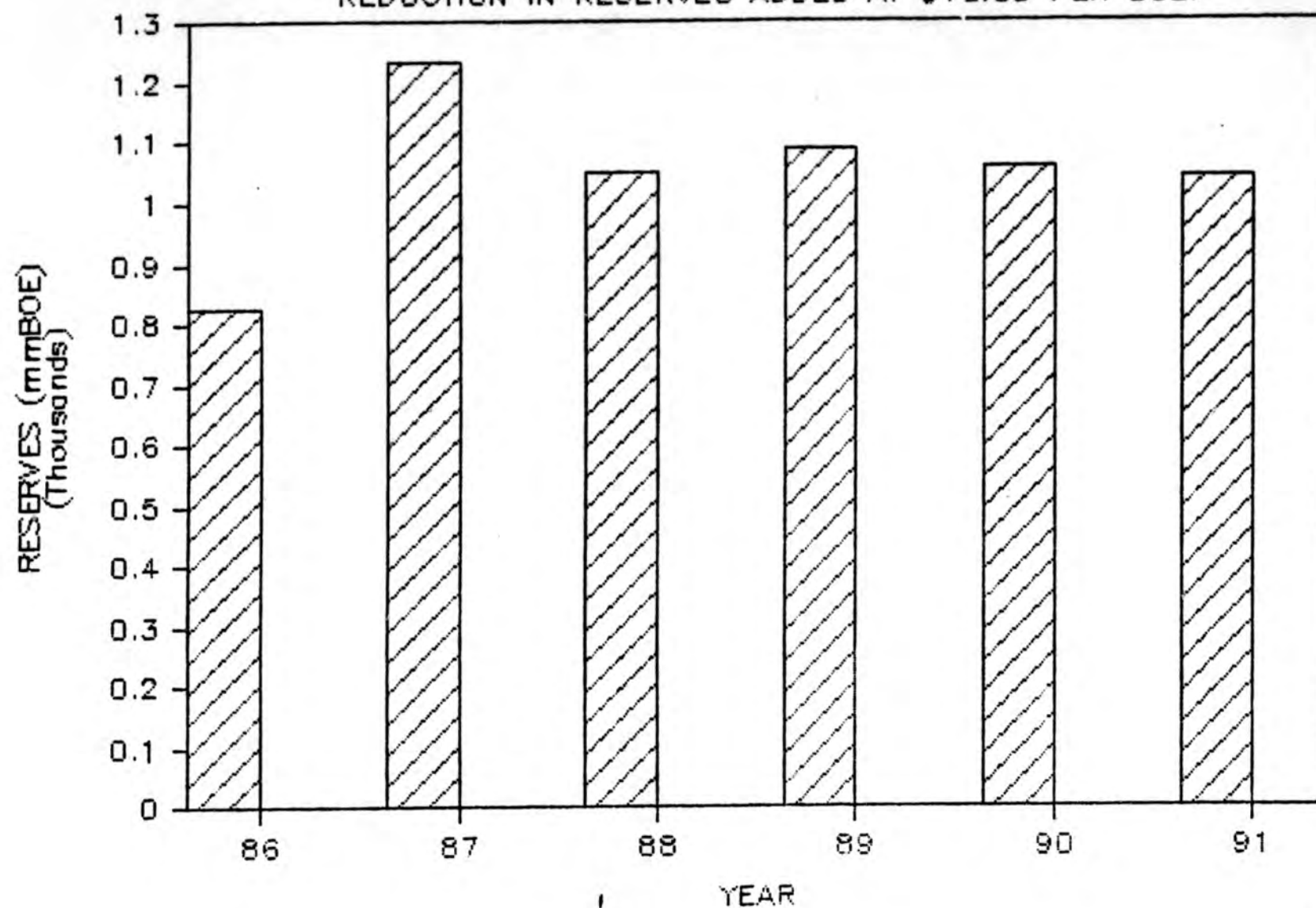
U.S. IMPACT OF IDC TAX PROPOSAL

REDUCTION IN DRILLING RIG RUNNING YEARLY

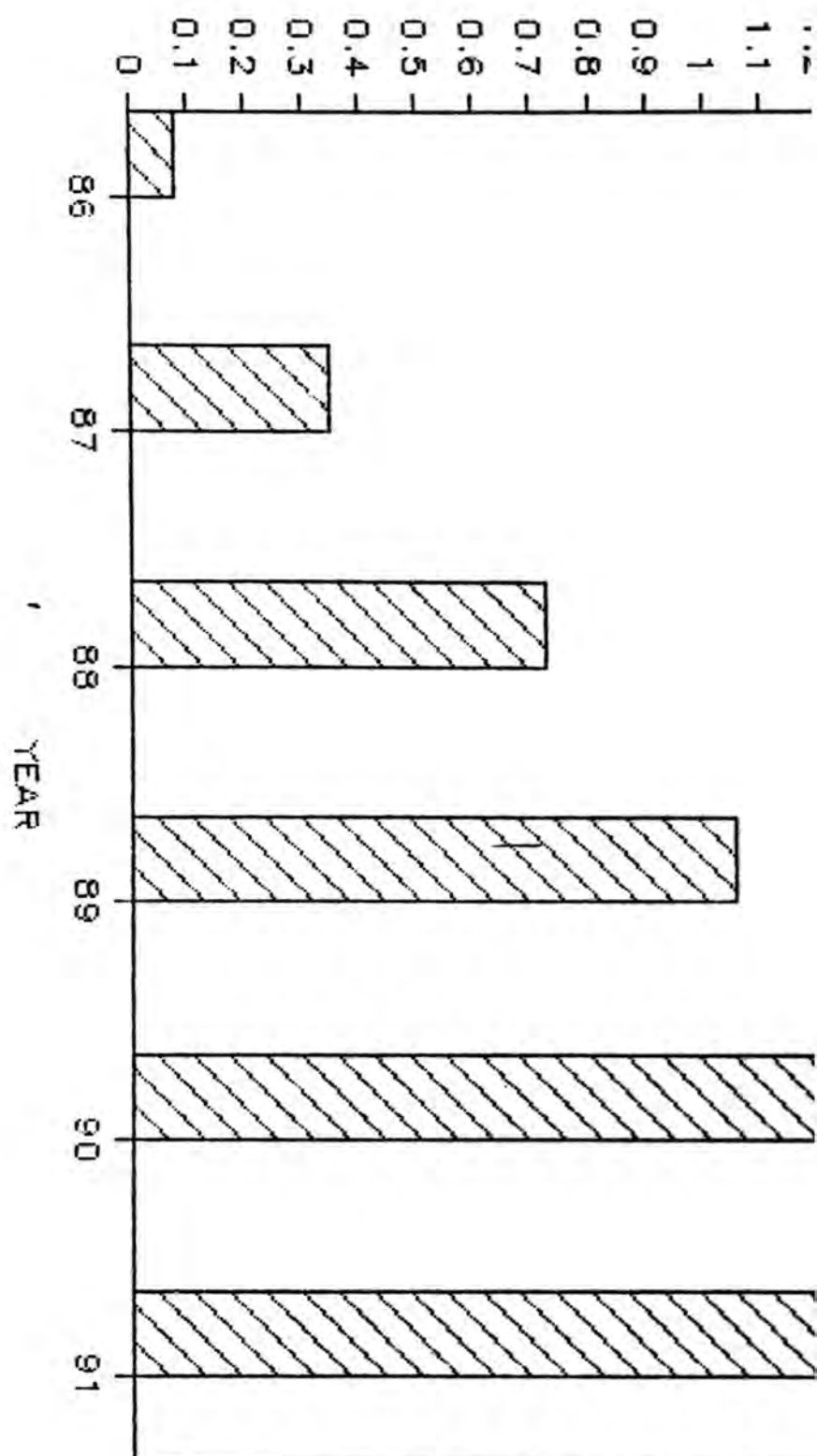


U.S. IMPACT OF IDC TAX PROPOSAL

REDUCTION IN RESERVES ADDED AT \$12.00 PER BOE:



PRODUCTION (BOE/DAY)
(Millions)

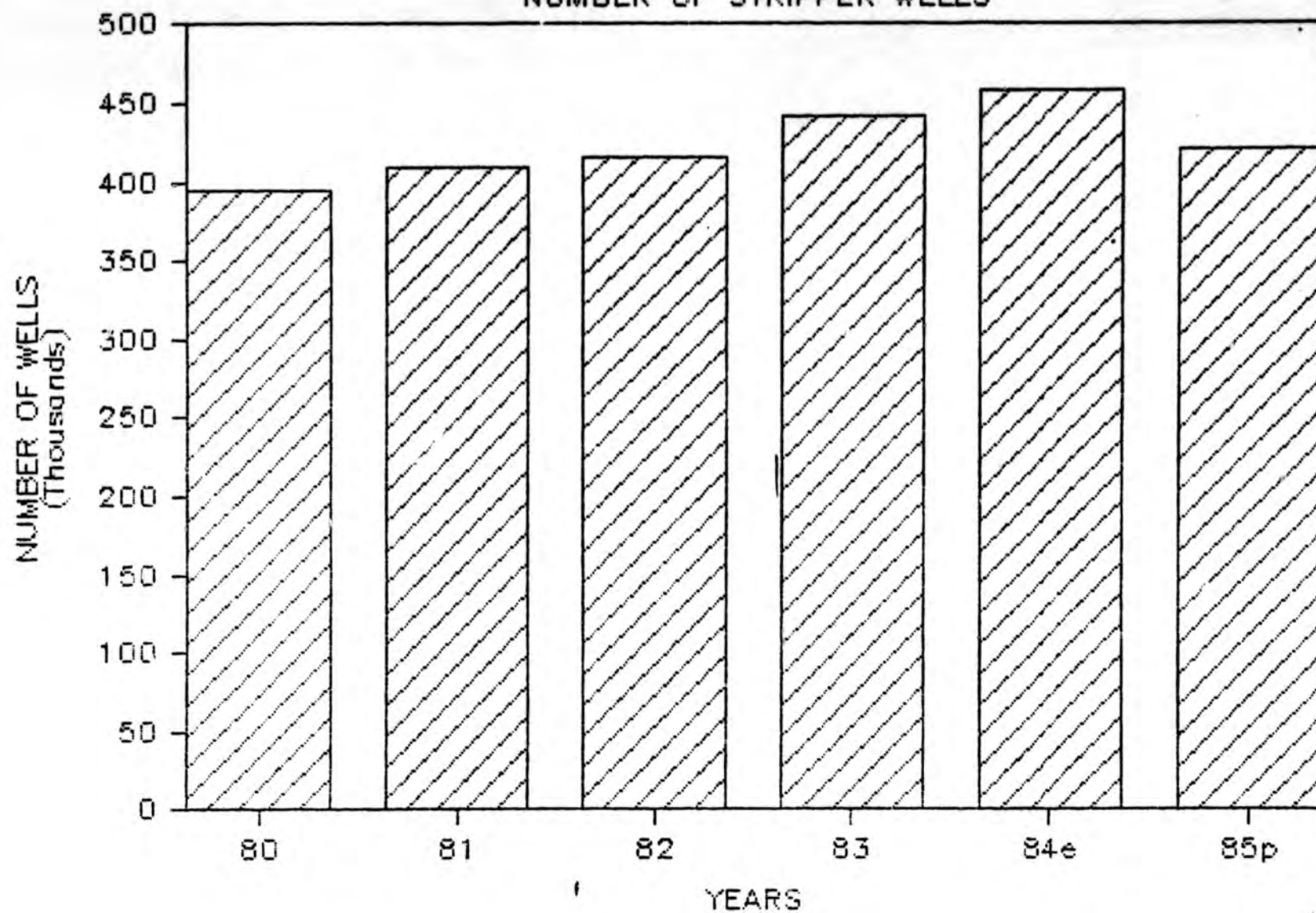


NATIONAL
STRIPPER WELL STATISTICS
1970 - 1983

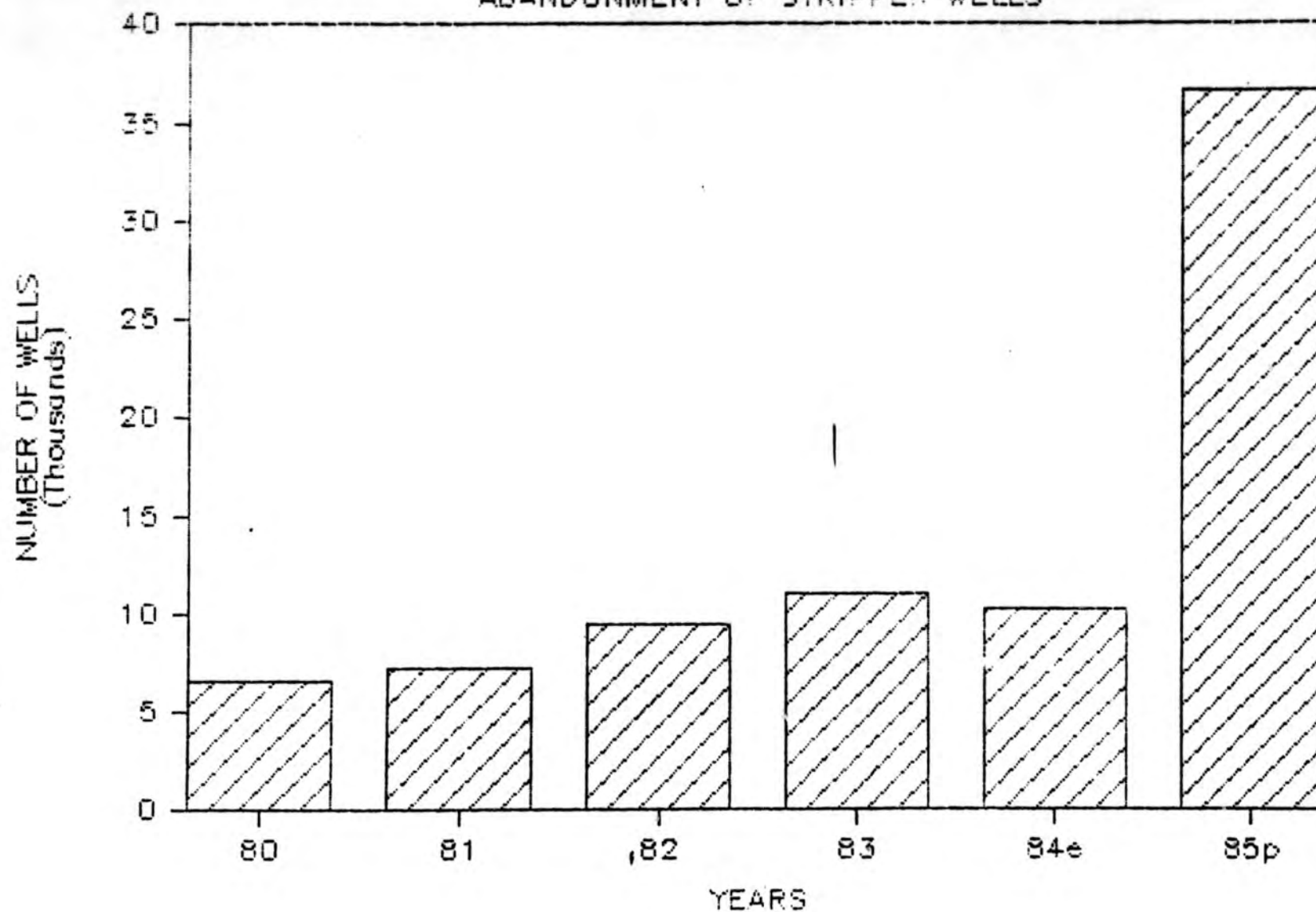
YEAR	STRIPPER WELL				AVERAGE DAILY PRODUCTION PER STRIPPER WELL (BPD)	TOTAL STRIPPER WELL ANNUAL PRODUCTION (mBBLs)	NATIONAL TOTAL PRODUCTION (mBBLs)	TOTAL STRIPPER WELL AVERAGE DAILY PRODUCTION (BPD)	TOTAL NATIONAL AVERAGE PRODUCTION (BPD)	PERCENT STRIPPER PRODUCTION	STRIPPER WELL RESERVES		
	NUMBER	ABANDONMENTS	ADDITIONS	ACRES							PRIMARY (mBBLs)	SECONDARY (mBBLs)	TOTAL (mBBLs)
1970	359,130	15,631	16,111	8,760,454	3.37	441.29	3,375.90	1,209,006	9,249,033	13.07%	2761.22	2197.99	4959.21
1971	353,696	18,421	12,987	8,761,081	3.58	423.32	3,223.40	1,159,786	8,831,230	13.13%	2659.90	2161.46	4821.35
1972	359,471	13,483	19,258	8,629,986	3.13	411.92	3,345.21	1,125,478	9,139,915	12.31%	2855.86	2026.04	4881.90
1973	355,229	13,756	9,514	8,741,387	2.97	385.68	3,206.44	1,056,667	8,784,753	12.03%	2981.80	1877.18	4858.97
1974	366,095	13,779	24,645	8,964,465	3.08	411.94	3,048.06	1,128,592	8,350,836	13.51%	3020.19	1866.26	4886.44
1975	367,872	13,478	15,255	9,218,949	2.93	394.16	2,804.68	1,079,898	7,684,063	14.05%	3004.29	1841.43	4845.72
1976	365,733	9,916	7,777	9,299,620	2.93	392.19	2,730.86	1,071,559	7,461,366	14.36%	2868.00	2008.32	4876.32
1977	368,930	9,000	12,197	9,423,161	2.91	392.53	2,672.82	1,075,430	7,322,795	14.69%	2901.35	2012.67	4914.03
1978	374,635	8,380	14,085	8,931,712	2.86	391.63	2,552.07	1,072,968	6,991,984	15.35%	2892.65	2107.25	4999.90
1979	386,310	7,668	19,343	9,154,803	2.79	394.41	2,420.48	1,080,562	6,631,444	16.29%	3003.95	2165.19	5169.14
1980	395,176	6,614	15,480	9,664,125	2.77	401.10	2,461.10	1,095,889	6,724,309	16.30%	3052.30	2130.24	5184.01
1981	409,539	7,215	21,578	9,683,564	2.85	426.50	2,137.97	1,168,500	5,857,458	19.95%	2628.59	1798.37	4426.96
1982	416,493	9,426	16,380	9,720,451	2.90	441.95	2,072.51	1,210,825	5,678,107	21.32%	2594.03	1860.37	4454.40
1983	441,501	11,032	36,040	10,411,234	2.87	462.01	2,125.02	1,265,790	5,821,973	21.74%	2579.65	2011.16	4590.81
1984*	457,482	10,229	26,210	10,788,089	2.87	480.55	2,125.02	1,316,571	5,821,973	22.61%	2683.13	2091.85	4774.98
1985p	420,885	36,597	0	9,925,079	2.93	450.87	2,095.34	1,235,261	5,740,663	21.52%	2205.82	1719.72	3925.53

* TOTAL PRODUCTION FROM THE STATES INCLUDED IN THE NATIONAL STRIPPER WELL SURVEY, 1971-1984

NATIONAL NUMBER OF STRIPPER WELLS



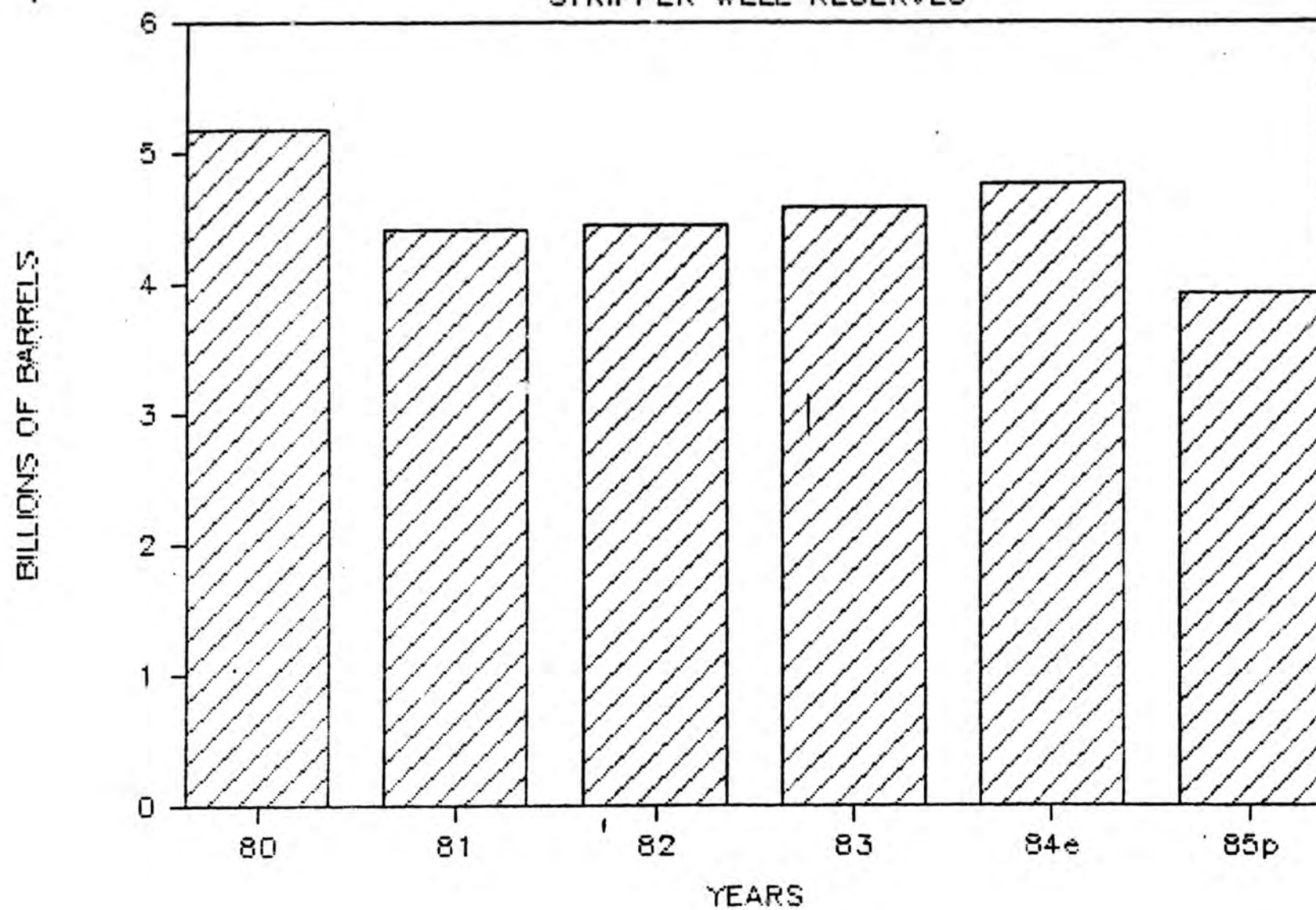
NATIONAL ABANDONMENT OF STRIPPER WELLS



NATIONAL STRIPPER WELL PRODUCTION



NATIONAL STRIPPER WELL RESERVES



IMPACT OF FEDERAL TAX PROPOSALS ON ENHANCED OIL RECOVERY (EOR)

	U.S.*	ALASKA*	ARKANSAS*	CALIFORNIA*	COLORADO*	FLORIDA*	KANSAS*
REDUCTIONS	(Millions of Dollars)						
IN ROYALTY PAYMENTS	10,351	184	77	1,221	200	42	65
IN PROPERTY & SEVERANCE TAX PAYMENTS	2,228	8	32	245	76	17	42
IN STATE INCOME TAX COLLECTIONS	635	66	17	77	9	6	(1)
IN FEDERAL INCOME TAX COLLECTIONS	1,313	(220)	74	(1,473)	4	(25)	(72)
IN PAYMENTS TO THIRD PARTIES	34,174	1,404	428	7,978	947	194	332
IN EQUIPMENT PURCHASES	2,250	14	6	(887)	26	3	9
IN IDC'S FOR EOR WELLS	896	8	5	44	75	32	212
TOTAL	51,847	1,464	639	7,205	1,337	269	587
IN EOR PRODUCTION#	1,832	94	21	423	54	6	17

* All impacts are cumulative.

Millions of barrels.

Basis:

- National Petroleum Council Enhanced Oil Recovery, June, 1984 and Bartlesville Project Office (DOE) EOR Data Base and Economic Model.
- Actual state by state current property and severance tax rates.
- Actual state by state income tax rates.
- Provisions of Secretary Regan's November, 1984 tax proposal regarding:
 - Intangible investments
 - Tertiary injectants
 - Revised ACRS depreciation
 - No tax credit
 - Modified depreciation schedules
 - Crude oil price of \$30.00 per barrel
 - 10% rate of return on investment

IMPACT OF FEDERAL TAX PROPOSALS ON ENHANCED OIL RECOVERY EOR

	U.S.*	KENTUCKY*	LOUISIANA*	MISSISSIPPI*	MONTANA*	NEBRASKA*	NEW MEXICO*
REDUCTIONS	(Millions of Dollars)						
IN ROYALTY PAYMENTS	10,351	0	(48)	60	86	29	806
IN PROPERTY & SEVERANCE TAX PAYMENTS	2,228	0	75	29	43	8	530
IN STATE INCOME TAX COLLECTIONS	635	4	(58)	6	11	3	92
IN FEDERAL INCOME TAX COLLECTIONS	1,313	13	(136)	28	54	12	353
IN PAYMENTS TO THIRD PARTIES	34,174	75	311	250	406	161	3,471
IN EQUIPMENT PURCHASES	2,250	0	(3)	8	10	5	95
IN IDC'S FOR EOR WELLS	896	0	(45)	29	19	2	271
TOTAL	51,847	92	96	410	629	220	5,618
IN EOR PRODUCTION#	1,832	0	(14)	16	23	8	288

* All impacts are cumulative.

Millions of barrels.

Basis:

- National Petroleum Council Enhanced Oil Recovery, June, 1984 and Bartlesville Project Office (DOE) EOR Data Base and Economic Model.
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- Provisions of Secretary Regan's November, 1984 tax proposal regarding:
 - Intangible investments
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 - Revised ACRS depreciation
 - No tax credit
 - Modified depreciation schedules
 - Crude oil price of \$30.00 per barrel
 - 10% rate of return on investment

IMPACT OF FEDERAL TAX PROPOSALS ON ENHANCED OIL RECOVERY EOR

REDUCTIONS	U.S.*	NORTH DAKOTA*	OKLAHOMA*	TEXAS*	UTAH*	WYOMING*	OTHER*
	----- (Millions of Dollars) -----						
IN ROYALTY PAYMENTS	10,351	193	768	1,558	(4)	41	5,073
IN PROPERTY & SEVERANCE TAX PAYMENTS	2,228	177	435	567	0	21	(77)
IN STATE INCOME TAX COLLECTIONS	635	34	70	0	(9)	0	308
IN FEDERAL INCOME TAX COLLECTIONS	1,313	82	469	(693)	(109)	(38)	2,990
IN PAYMENTS TO THIRD PARTIES	34,174	913	3,629	9,656	(26)	227	3,818
IN EQUIPMENT PURCHASES	2,250	23	60	432	0	6	2,443
IN IDC'S FOR EOR WELLS	896	41	69	408	0	(19)	(255)
TOTAL	51,847	1,463	5,500	11,928	(148)	238	14,300
IN EOR PRODUCTION [#]	1,832	51	209	465	(1)	12	

* All impacts are cumulative.

[#] Millions of barrels.

Basis:

- National Petroleum Council Enhanced Oil Recovery, June, 1984 and Bartlesville Project Office (DOE) EOR Data Base and Economic Model.
- Actual state by state current property and severance tax rates.
- Actual state by state income tax rates.
- Provisions of Secretary Regan's November, 1984 tax proposal regarding:
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 - Crude oil price of \$30.00 per barrel
 - 10% rate of return on investment