Appendixes

Offshore Leasing Systems

U.S. Federal Leasing System for Offshore Areas

Description

Federal offshore leasing is conducted according to the guidelines contained in the Outer Continental Shelf (OCS) Lands Act of 1953, as amended in 1978, which authorizes the Secretary of the Interior to grant mineral leases for OCS lands and to prescribe any necessary regulations. Currently, the Minerals Management Service (MMS) within the Department of the Interior is responsible for implementing the offshore leasing system and the operating regulations.

In general, the Interior Department identifies an area for leasing in accordance with a pre-set lease schedule. It surveys the hydrocarbon potential, calls for information, and prepares a draft environmental impact statement. After filing a final environmental impact statement with the Environmental Protection Agency, the lease sale is announced and comments are solicited from the States and other interested parties. With appropriate modifications, the lease sale takes place and firms are awarded offshore tracts according to a competitive bidding process. In the post-lease phase, companies must submit extensive safety and environmental protection plans with each stage of exploration, development, and production. The post-lease management functions of the Department of the Interior involve approval and enforcement of the plans and collection of government revenues. The pre-lease and post-lease steps of the leasing process are outlined in table A-1 and figure A-1.

LEASE SCHEDULE

Prior to the enactment of the OCS Lands Act Amendments of 1978, the Department of the Interior was not required to develop a prospective leasing program or plan. Between the start of leasing in 1954 and 1967, nearly all offshore tracts nominated by the industry were offered for leasing. However, in 1967, the Department of the Interior instituted a formal nomination and selection system that required a resource evaluation and determination of industry interest before tracts were offered for sale. Subsequent to the passage of the OCS Lands Act Amendments of 1978, leasing programs have been developed in accordance with Section 18 of the Act, which requires that the Secretary of the Interior prepare and periodically review a 5-year leasing schedule which is consistent with the principles of the Act.

The selection of areas to be included in the lease schedule is influenced by initial assessments of oil and gas potential, environmental concerns, economic conditions, location of commercial fisheries, availability of technology, and other factors. Geological and environmental information on the Outer Continental Shelf is collected and evaluated by the Department of the Interior. Companies may obtain permits for preliminary offshore exploratory activity, including broad area reconnaissance to identify promising geologic formations and requirements for more detailed seismic surveys. In certain circumstances, permits may be granted to firms to take bottom samples or cores (COST wells) to obtain additional geologic information. The government may request the submission of all pre-lease geological and geophysical data and information.

Final approval of the 5-year OCS leasing program takes approximately 2 years. Comments are solicited from the States, industry, Federal agencies, and other interested parties at several points in the development of the plan. After comments are received and appropriate modifications are made, the final schedule is submitted to the President and Congress for review.

CALL FOR INFORMATION

The initiation of individual lease sales begins with the identification of areas of hydrocarbon potential by the Department of the Interior. A Call for Information is issued for a large area, usually consisting of several million acres, and is published in the *Federal Register* with a 45-day comment period. Potential bidders are asked to identify areas they wish to have offered for lease. States and other interested parties may identify and recommend areas which should be excluded from oil and gas leasing or only leased under special conditions because of conflicting resource values or environmental concerns. At the same time, a Notice of Intent to prepare an Environmental Impact Statement (EIS) is published, which invites public assistance in determining significant issues. The information received from the public, as well as the resource, environmental, and technical information collected by the Department of the Interior, are used to identify an area for further analysis in the EIS.

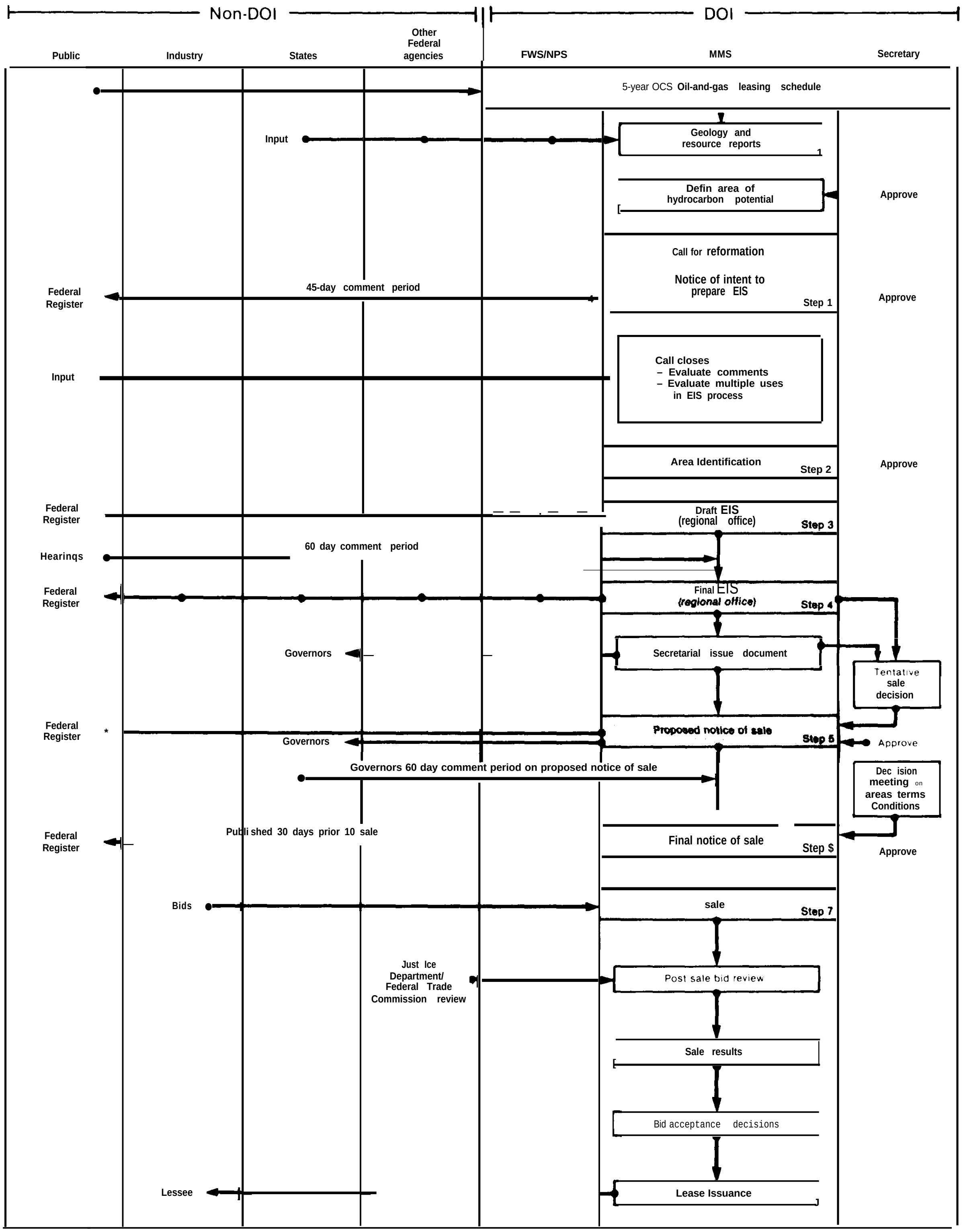
In the proposed 1986-91 5-year leasing schedule, an additional lease sale step has been added for selected frontier-area sales. A Request for Interest will be made four months prior to the Call for Information. This request will help determine industry interest in leasing in these areas and whether the 2-year sale process should

Table A-1.–Steps in Offshore Leasing (1984)

Activity	Timeframe: month Lower 48	Alaska	Action
Pre-lease phase:			
Five-Year Leasing Program	2-5 years prior to to call		Prepare schedule of proposed lease sales, to be revised annually. Industry, states, and other parties comment prior to final approval.
Identify area of Hydrocarbon Potential	At least 2 months prior to call		Identify area of hydrocarbon potential (AHP) for upcoming sale.
Call for Information; Publish Notice of Intent to Prepare EIS	1	1	Request bidders to indicate areas of interest and solicit comments from all interested parties. Due in 45 days. Also announce initiation of EIS scoping.
Area Identification	4	4	Identify areas for detailed environment analysis.
Draft Environmental Impact Statement	12	15	Draft EIS issued for planning area and notice published in Federal Register. Comments requested and hearings held during 60-day comment period.
Final Environmental Impact Statement	18	21	Revised EIS submitted to EPA for review and made available to public.
Proposed Notice of Lease Sale	19	22	Proposed notice of sale, with terms and conditions, sent to States for comment for a 60-day period.
Final Notice of Lease Sale	22	25	Final notice of sale published in Federal Register at least 30 days prior to sale.
Lease Sale	23	26	Regional office holds public opening and reading of sealed bids.
Leases Issued	25	28	Leases issued not later than 90 days later, after bid review and anti-trust review.
Post-lease phase:			
Exploration Plan	Within 4 years of lease issue (for 5-year terms)		Lessee submits exploration plan and environmental report. States evaluate for CZM consistency.
Environmental Analysis			MMS conducts environmental analysis, prepares EIS if necessary, and approves or rejects plan.
Exploration Drilling	For all exploration wells		Lessee submits application to drill (APD) and applies for permits from other agencies. After analysis, MMS approves or rejects.
Development and Production Plan	Within 5 years of lease issue/or receives SOP		Lessee submits development and production plan and environmental report. States review for CZM consistency.
Environmental Analysis			MMS conducts environmental analysis, prepares EIS if necessary, and approves or rejects plan.
Development Drilling	For all exploration wells		Lessee submits APO and required permits, State CZM ruling, and platform verification and certification. MMS approves or rejects.
Pipeline Permits			Lessee applies for pipeline permits from MMS and other relevant agencies.
Production	For duation of production		Lessee submits monthly production reports and royalty payments.
Relinquishment	Cancellation or shutdown		Wellheads plugged and equipment removed.

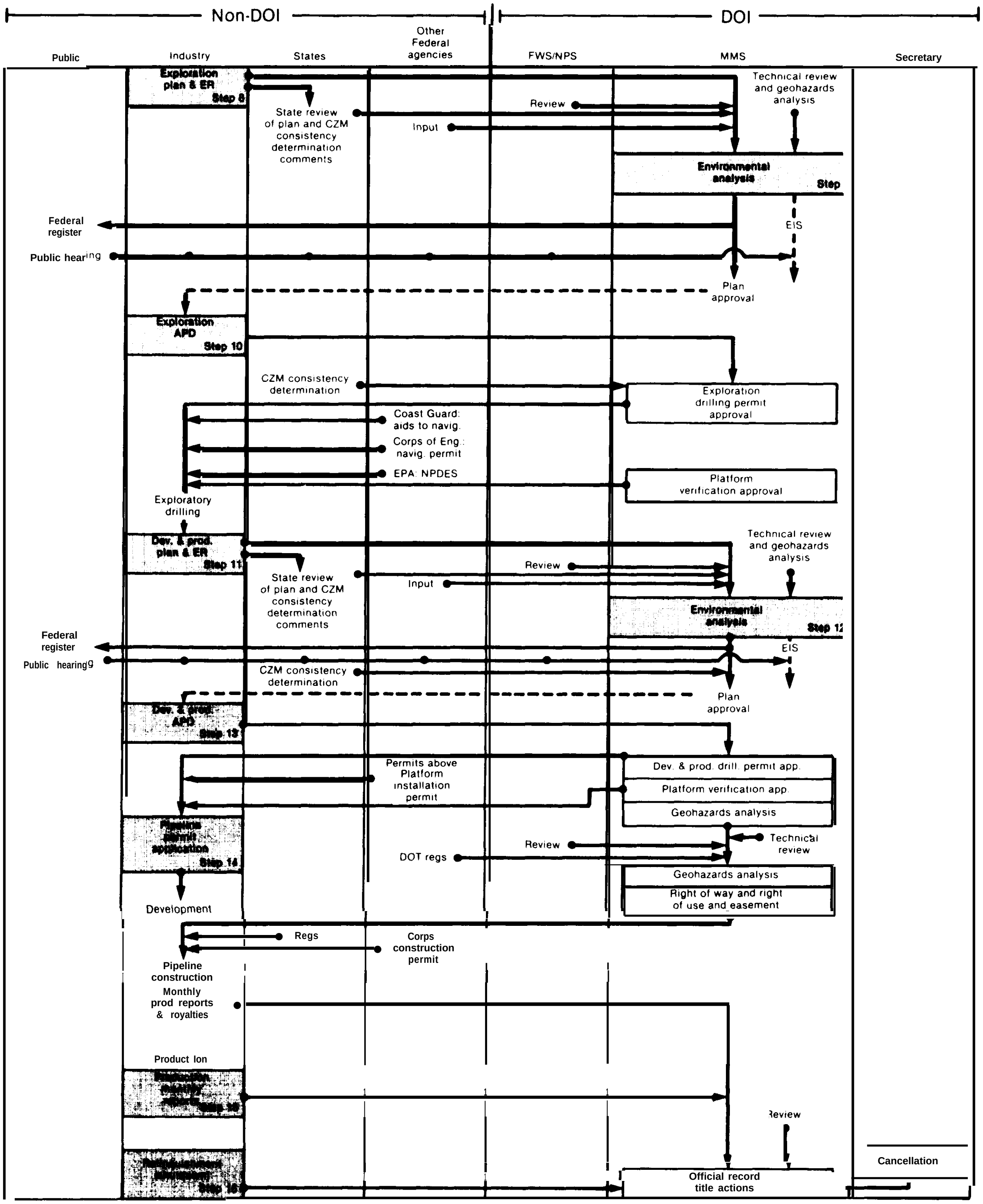
SOURCE: Office of Technology Assessment.

Figure A-1.—Offshore Leasing Process: Pre-Lease



SOURCE Minerals Management Service

—Offshore Leasing Process: Post-Lease



SOURCE: Minerals Management Service

proceed. The Request for Interest will be made for the following Alaska sales: Gulf of Alaska (1988); Cook Inlet (1990); Shumagin (1990); Hope Basin (1991); and Kodiak (1991).

ENVIRONMENTAL ASSESSMENT

The National Environmental Policy Act (NEPA) of 1969 requires the analysis, assessment, and disclosure of environmental impacts that may result from Federal offshore leasing. The environmental assessment process for offshore lease sales involves the preparation of preliminary and final environmental impact statements, public hearings, and consultation with affected States and all interested parties.

The first step is the preparation of a Draft Environmental Impact Statement (DEIS) by the Department of the Interior. For the first sale in a planning area, the DEIS is prepared for the entire area; abbreviated statements are prepared for subsequent sales. The DEIS includes a description of the lease proposal, a description of the marine and nearby onshore environment, a detailed analysis of possible adverse impacts on the environment, the technology to be used, the socioeconomic impacts, mitigating measures proposed, alternatives to the proposal, and the records of consultation and coordination with others in preparation of the statement. The DEIS is published in the *Federal Register* with a 60-day comment period, and public hearings on the DEIS are held within the vicinity of the proposed lease sale.

A Final Environmental Impact Statement (FEIS) is then prepared taking into account the comments received during the review period and at the public hearings. The FEIS is filed with the Environmental Protection Agency and made available to the public.

NOTICE OF LEASE SALE

At least 30 days after the submission of the FEIS to the Environmental Protection Agency, a final decision is made by the Secretary of the Interior as to whether or not the proposed sale will be held. A Secretarial Issue Document (SID) is first prepared which analyzes the issues and options pertaining to the sale area, and includes information on alternative terms and procedures to be used in the lease sale. If the decision is to hold a sale, the SID and the final EIS are submitted to the affected States for comment within 60 days. A Proposed Notice of Lease Sale is published in the *Federal Register* identifying the blocks to be leased and the leasing stipulations, terms, and procedures.

After the 60-day comment period, the Final Notice of Lease Sale is published in the *Federal Register.* Taking into consideration public comments and State concerns, the final notice lists the tracts to be included in the sale, the terms under which the sale will be held, and any special stipulations that may be imposed on particular tracts. It also gives at least a 30-day notice of the date, place, and time that bids are to be opened.

LEASE SALE

All leases are sold through a competitive bidding process with firms submitting separate sealed cash bids for each individual tract. All bids are opened and read at a public sale, after which the bids are checked for technical and legal adequacy. In addition, a determination of the adequacy of the high bids is conducted. The acceptance or rejection of each bid occurs within 90 days after the lease sale is held.

LEASE CONTRACT

The oil and gas lease contract grants the right to the lessee to conduct necessary operations to explore, drill and produce oil and gas from a specific tract. The primary term of the lease contract is usually 5 years, although 10-year terms are granted for special conditions, such as ice-prone areas or deepwater sites. During this time, oil and gas in commercial quantities must be found or approved drilling or well reworking operations must be conducted, or the lease is forfeited. Leases may be extended beyond the initial lease terms as long as production is occuring, drilling or well reworking is undertaken, or a special suspension order is obtained.

EXPLORATION

The lessee is obligated to proceed diligently to explore and develop the tract and must submit an exploration plan to the Department of the Interior for approval by the fourth year of a 5-year lease. Details of drilling technology, geophysical equipment, location of exploratory wells, oil spill contingency plans, an air quality analysis, and other relevant geological and geophysical information must be included in the plan. The exploration plan must be accompanied by an environmental report, and certifications of consistency must be obtained from coastal States under the Coastal Zone Management Act. After an environmental assessment, an environmental impact statement if necessary, and a technical review, the Department of the Interior approves, rejects, or modifies the exploration plan.

Before exploratory drilling can be initiated, an Application for Permit to Drill (APD) must be submitted. This includes detailed information on equipment design, well location and depth, and potential geophysical hazards. Additional approvals are required each time a well is deepened, reworked, redrilled, or plugged back. In addition to the Department of the Interior permit to drill, appropriate permits must be received from the

U.S. Coast Guard, U.S. Army Corps of Engineers, Environmental Protection Agency, and other federal agencies to satisfy environmental or safety requirements.

DEVELOPMENT AND PRODUCTION

The planning, environmental assessment, and approval process starts anew when oil and gas is discovered on a tract. A detailed Development and Production Plan and accompanying environmental report must be submitted by the lessee to the Department of the Interior for approval. Certifications of consistency also must be obtained from the coastal zone management programs of the affected States. The plan and environmental report are reviewed by a number of Federal agencies and affected States, and the Department of the Interior prepares its own environmental evaluation and technical review. In addition, a separate platform verification and certification process, involving third-party verification agents, is initiated for the evaluation and monitoring of platform design, fabrication, and installation.

An APD must be received prior to drilling any development well, and any reworking of development wells also must be approved. All other necessary Federal permits, such as for offshore structures, navigation aids, and pollution discharge, must be obtained prior to approval of the APD by the Department of the Interior. Permits and approvals also must be received for the construction and operation of offshore pipelines and for any significant modification of production equipment and procedures. As production proceeds, the Department of the Interior is responsible for on-site inspection and monitoring of offshore operations. The lessee must submit monthly reports of operations and royalty payments to the government.

RELINQUISHMENT

Leases expire at the end of their initial term unless actual production is occurring or a suspension of production or operation (SOP) is received for development activities or approved drilling or well reworking operations. Leases may also be relinquished by a lessee or cancelled by the Department of the Interior for noncompliance with OCS regulations. At the time of abandonment, the operator must plug the wells in accordance with Interior requirements. All oil and gas zones must be isolated by the installation of cement plugs to ensure a permanent seal. All pipe casings must be cut off below the ocean floor and the well location must be cleared.

Offshore Leasing Revenues

LEASE PAYMENTS

Revenues from offshore leasing consist of bonuses, rents, and royalties in addition to taxes. Bonuses are advance cash payments made by companies for the right to explore and develop particular tracts. Rents are annual fees, now set at $3 per acre, paid on leased acreage. Royalties are pre-set percentages of the value of oil and gas production paid after production begins. The standard royalty rate on offshore production has been 16⅔ percent, although some tracts have been leased with 12½ percent and 33⅓ percent royalties. A few tracts also have been leased with profit share payments and sliding scale royalties rather than fixed royalties.

From the start of the OCS leasing program in 1954 to the end of 1983, bonuses, rents, and royalties from offshore leases have totaled approximately $68 billion (see table A-2). OCS receipts increased from an average of $280 million per year in the 1950s and 1960s to an average of $3 billion per year in the decade of the 1970s. In the early 1980s, OCS receipts averaged more than $8 billion per year. In general, the level of receipts has increased with the quantity of acreage leased, the amount of oil and gas produced, and increases in energy prices.

Bonuses have comprised the largest share of government lease payments (69 percent) other than taxes and account for most of the variation in annual OCS receipts. Bonus receipts increased substantially in 1973-74, as a result of the Nixon administration initiatives to increase offshore leasing, and in 1979-83 as leasing was again accelerated. In 1981, bonus receipts reached a high of $6.6 billion for over 2 million leased acres. Bonus revenues declined from the 1981 level in 1982 and 1983, due to depressed oil prices, the more costly and risky nature of the deepwater and Alaskan tracts being leased, and other factors.

From 1953 to 1983, a total of 6 billion barrels of oil and 62 trillion cubic feet of gas were produced in Federal offshore areas. Although offshore oil production declined every year between 1971 and 1980, it again turned upward in 1981 when 286 million barrels of oil were produced. In 1983, Federal offshore hydrocarbon production represented approximately 11 percent of the oil and 24 percent of the natural gas produced in the United States, The cumulative value of the oil and gas produced offshore between 1953 and 1983 is estimated at $128 billion, of which $20 billion or 16 percent was paid to the Federal Government in royalties. Lease payments by companies (not counting taxes) accounted for

Table A-2.—OCS Acreage, Production, and Revenues (1953-1983)

Year	Sales	Acreage Offered	Acreage Leased	Production Oil (mbbl)	Production Gas (tcf)	Revenues ($ billion) Bonuses	Royalties	Rents*	Total
1953				1	0.020	0.000	0.001	0.001	0.002
1954	3	1384238	486870	3	0.056	0.141	0.003	0.004	0.148
1955	1	674095	402567	7	0.081	0.108	0.005	0.003	0.116
1956	0	0	0	11	0.083	0.000	0.008	0.004	0.012
1957	0	0	0	16	0.083	0.000	0.011	0.003	0.014
1958	0	0	0	25	0.127	0.000	0.018	0.002	0.020
1959	2	539813	171300	36	0.207	0.090	0.027	0.002	0.119
1960	2	1632339	707026	50	0.273	0.283	0.037	0.004	0.324
1961	0	0	0	64	0.318	0.000	0.048	0.003	0.051
1962	3	3718115	1929177	90	0.452	0.489	0.067	0.008	0.564
1963	1	669777	312945	105	0.564	0.013	0.078	0.008	0.099
1964	2	1124102	613524	123	0.622	0.096	0.089	0.010	0.195
1965	1	947520	72000	145	0.646	0.034	0.104	0.009	0.147
1966	3	265886	141768	189	1.007	0.209	0.144	0.007	0.360
1967	2	988484	746951	222	1.187	0.510	0.160	0.006	0.676
1968	3	1315984	934164	269	1.524	1.346	0.203	0.008	1.557
1969	3	355758	114282	313	1.954	0.112	0.242	0.009	0.363
1970	2	666845	598540	361	2.419	0.945	0.285	0.009	1.239
1971	1	55872	37222	419	2.777	0.096	0.352	0.008	0.456
1972	2	970711	826195	412	3.039	2.251	0.366	0.008	2.625
1973	2	1514940	1032570	395	3.212	3.082	0.404	0.009	3.495
1974	4	5006881	1762158	361	3.515	5.023	0.562	0.014	5.599
1975	4	7247327	1679877	330	3.459	1.088	0.618	0.018	1.724
1976	4	2827342	1277937	317	3.596	2.243	0.702	0.023	2.968
1977	2	1843116	1100734	304	3.738	1.568	0.921	0.020	2.509
1978	4	3140696	1297274	292	4.385	1.767	1.152	0.022	2.941
1979	6	3413352	1767443	286	4.673	5.079	1.517	0.020	6.616
1980	3	2563452	1134238	277	4.641	4.205	2.139	0.019	6.363
1981	7	7679740	2237005	286	4.880	6.602	3.274	0.021	9.897
1982	5	5815872	1886360	321	4.679	3.987	3.815	0.020	7.822
1983	8	120094037	6593517	341	3.940	5.749	3.376	0.037	9.161
Totals	77	176456294	29863644	6371	62.157	47.116	20.728	0.339	68.182

*Includes minimum royalties, shut-in gas, etc.

SOURCE: Minerals Management Service.

about 53 percent of the total value of oil and gas production in that period.

The greatest share of OCS receipts (83 percent) has been from the Gulf of Mexico (see table A-3 and figure A-2). The Gulf of Mexico, predominantly offshore Louisiana, accounts for over 99 percent of all natural gas production and 96 percent of all oil production in Federal offshore areas. The balance of offshore oil and gas production in Federal waters is from offshore California. As a result, the Gulf of Mexico has accounted for 77 percent of bonus revenues, 97 percent of oil and gas royalties, and 79 percent of all rents received. Leasing

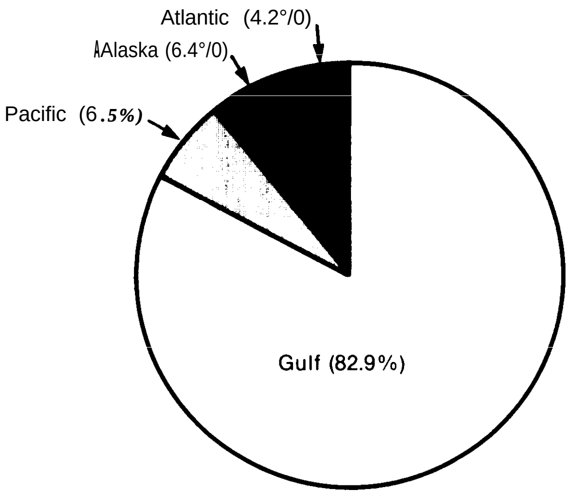
Table A-3.—OCS Regions: Production and Revenues (1953-1983)

Regions	Production oil (mbbl)	Production Gas (bcf)	Revenues ($million) Bonuses	Royalties	Rents	Total
Gulf	6,096	62,037	36,076	20,196	269	56,541
Pacific	275	120	3,840	532	31	4,403
Alaska	0	0	4,360	0	22	4,382
Atlantic	0	0	2,840	0	17	2,857
Total	6,371	62,157	47,116	20,728	339	68,183

mbbl - million barrels
bcf-billion cubic feet

SOURCE: Minerals Management Service,

Figure A-2.—Federal Revenues From OCS Regions 1953-1983



SOURCE: Office of Technology Assessment

in the Alaskan and Atlantic offshore regions began in 1976, and while they have contributed some bonus revenues and rents, there is as yet no oil and gas production or royalty revenues from these regions.

FEDERAL TAXES

In addition to lease payments, companies also pay Federal taxes on offshore oil and gas production. In general, the oil and gas producing industry in the United States benefits from special tax provisions designed to encourage domestic energy exploration and production. In recent years, this tax advantage has been reduced by the Crude Oil Windfall Profits Tax. Offshore oil and gas producers may currently expense and deduct certain costs, including intangible drilling costs (up to 80 percent) and dry hole costs, which would normally be recovered through depreciation. Oil and gas producers also benefit from two general provisons of the Federal tax code available to all business: the depreciation deductions under the Accelerated Cost Recovery System and the regular 10 percent investment tax credit.

In 1980, Congress enacted the Crude Oil Windfall Profits Tax, an excise tax per barrel on the difference between the crude oil market price and an established base oil price. The rate varies between 15 and 70 percent depending on the oil tier (e. g., old oil, stripper oil), type of producer, and year of production. The tax on newly discovered oil is to be phased down from the current 22.5 percent to 20 percent in 1988 and to 15 percent in 1989 and thereafter. The Windfall Profits Tax does not apply to oil production from Arctic areas. The Windfall Profits Tax should not apply to oil producers in other offshore frontier areas, as the base price should exceed the market price before fields come on stream in these regions.

REVENUE TRENDS

Owing to the substantial funds received by the Federal Government from offshore leasing, there has been controversy regarding the relationship between offshore leasing and revenue policy. It is widely believed that the pace of leasing has been partly dictated by budget concerns. In the early years of leasing, the Department of the Interior was accused of maintaining a deliberately slow rate of leasing in order to keep the demand for leases and bonus revenues high. In the 1970s, the General Accounting Office (GAO) charged that the government accelerated leasing in order to increase revenues for the general Treasury. Similarly, the accelerated leasing schedule which began in 1982 is believed by some to stem partly from the need to generate revenues and reduce the large Federal budget deficit.

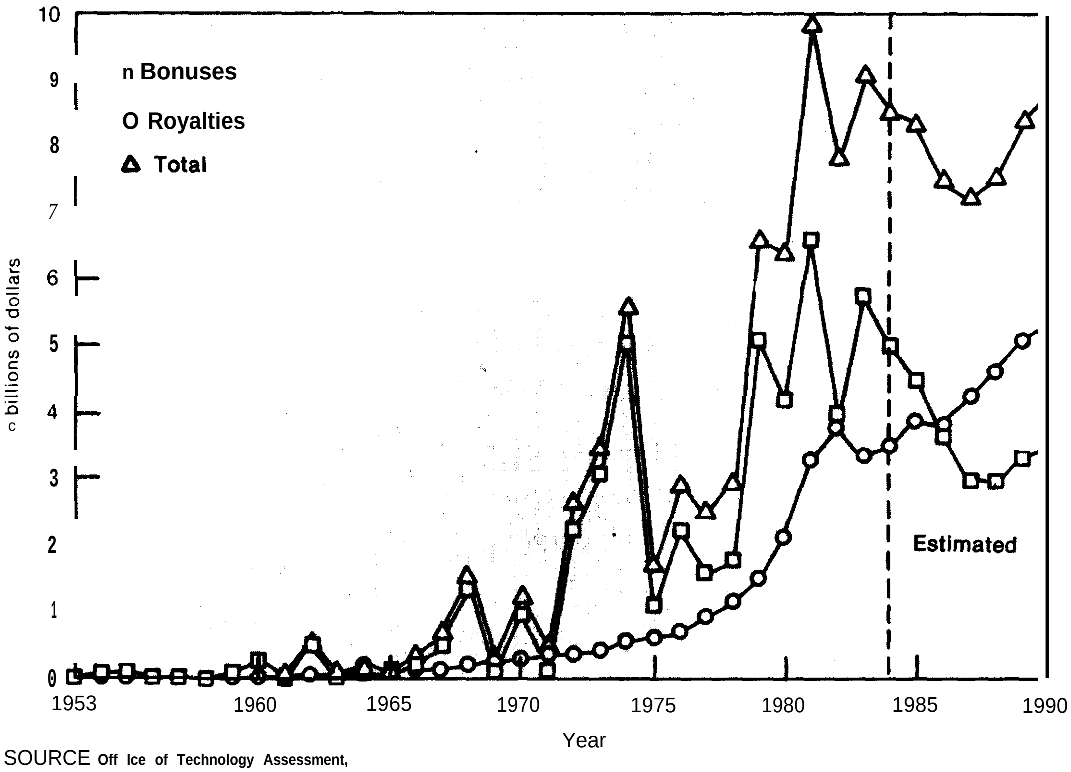
Budget concerns may have also influenced government forecasts of future revenues from OCS leasing. It is difficult to project OCS receipts because of the subjective nature of resource estimates, unpredictability of future prices and development costs, and unforseen changes to lease schedules. The Office of Management and Budget (OMB) has overestimated—by a factor of 2 or more—projected receipts from offshore leasing in the 1980s. The original OMB budget estimates for fiscal year 1984 were for $18 billion in receipts from OCS leasing; this was later revised downward to $12 billion; however, actual fiscal year 1984 OCS leasing revenues were in the area of $8-9 billion. For fiscal year 1985, OMB has again projected $12 billion in OCS revenues, as compared to a Department of the Interior estimate of $6 billion.

The Department of the Interior projects that royalty revenues will surpass bonus revenues for the first time in 1985-86 (see figure A-3). Interior forecasts show that annual bonus revenues will decline to an average $2 to $3 billion per year while royalties level off at $3 to $4 billion per year during 1985-89. At the same time, the costs of post-lease management activities will rise as a result of the increases in leased acreage and the difficulty of operating conditions in frontier areas. The balance between income from offshore leasing and the costs of management programs may change as leasing proceeds in offshore frontier areas.

State Offshore Leasing Policies

The offshore leasing systems used by the coastal States are similar to that used by the Federal Government. Certain aspects of the Federal leasing process were

Figure A-3. —OCS Revenues Forecast
Bonuses and Royalties



SOURCE Off Ice of Technology Assessment,

adapted from the State experience, such as the one-sixth royalty rate which was that traditionally used for offshore tracts by the State of Louisiana. Louisiana, California, and Texas leased offshore lands under their jurisdiction prior to the enactment of the Submerged Lands Act of 1953, which established offshore State/Federal boundaries, and the 1953 OCS Lands Act, which provided guidelines for the Federal system. Through 1983, the States accounted for 39 percent of the oil and 19 percent of the natural gas produced in the offshore areas of the United States. Currently, State offshore oil and gas production is decreasing. Production in Federal waters now accounts for about 80 percent of total offshore oil production and 88 percent of total offshore gas production.

Although Florida, Alabama, Mississippi, and Washington State have leased offshore tracts, the States of Louisiana, California, Texas, and Alaska have accounted for most of the State offshore activity and are the only States to have offshore hydrocarbon production (see table A-4). Since the start of State leasing in the 1920s, Louisiana has accounted for most of the wells drilled and hydrocarbons produced in State waters. California, which has not issued any leases since 1969, accounts for the highest percentage of oil and condensate produced in State offshore areas. Currently, most State drilling activity is centered off Louisiana and Texas.

Table A-4.—State Offshore Leasing Statistics (cumulative through 1983)

State	Wells drilled	Production: Oil* (mbbl)	Production: Gas (bcf)
Louisiana	4,688	1,338	9,654
California	3,598	1,884	716
Texas	1,451	26	2,877
Alaska	379	816	1,126
Other	29	0	0
Total State	10,145	4,064	14,373
Total Federal	22,095	6,371	62.157

“Includes condensate.
mbbl - million barrels.
bcf - billion cubic feet,

SOURCE: Minerals Management Service.

The leasing process used by the States is generally similar to the Federal system in its administrative framework, competitive bidding system, and lease terms (see table A-5). As does the Federal Government, the

Table A-5.—Comparison of Federal and State Leasing Policies

	Federal	Louisiana	California	Texas	Alaska
Lead Leasing Agency	Minerals Management Service	State Mineraal Board	State Lands Commission	School Land Board	Department of Natural Resources
Permitting Agencies	EPA, Coast Guard, Army Corps of Engineers	Office of Conservation, Depts. of Natural Res., Env. Quality, and Wildlife & Fish	Coastal Commission (in dispute)	State Railroad Commission	Oil and Gas Cons. Comm. Dept. of Env. Cons. Dept. of Fish and Game Office of the Governor
Frequency of Sales	5-8 year	Monthly	Not since 1969	Twice a year	At least 3 per year
EIS Requred	Yes	No	Yes	No	Yes (for major sales)
Lease Term	5/10 years	5 years	20 years	5 years	10 years
Primary Bidding System	Cash bonus bid/ fixed royalty	Cash bonus and royalty bid	Cash bonus bid/ sliding royalty	Cash bonus bid/ fixed royalty	Cash bonus bid/ fixed royalty
Royalty Rate	12½% or 162/3 0/0	Estimated 21 -26°/0	Estimated 25%	250/o	200/0
Rental	$3 per acre annually	1/2 cash bonus	$1 per acre annually	$1 per acre annually	$1 per acre annually
Taxes	Corporate Income Tax Windfall Profits Tax (except in Arctic)	Severance Tax (12.50/,)	Corporate Income Tax (9%)	Severance Tax (4.6°/0 oil/ 7.50/0 gas)	Corporate Income Tax (9.4%) Severance Tax (12.5-15°/0) Property Tax

SOURCE: Office of Technology Assessment.

States receive revenues from offshore leasing in the form of cash bonuses, royalties, and other types of lease payments, and from various tax levies. The States have typically set higher royalty rates on production than the Federal Government, largely because State offshore areas are nearer to shore and less costly and risky to explore and develop than Federal waters.

Louisiana

Most oil and gas activity in State offshore areas has been off the coast of Louisiana, which has developed a sizeable onshore support, service, and refining base. The first offshore tract was leased in the 1920s, and through 1983, almost 4,700 wells had been drilled in Louisiana waters. Oil and gas production from offshore Louisiana has been declining since the early 1970s. In 1983, Louisiana produced 24 million barrels of oil and 316 million cubic feet of natural gas. In contrast, production in Federal waters offshore Louisiana in 1983 was about 290 million barrels of oil and almost 3 billion cubic feet of gas. Approximately 40 percent of Louisiana's 1 million acres of State offshore lands was under lease as of 1983.

Louisiana conducts monthly lease sales, and State revenues have depended heavily on offshore leasing. The bidding system used in Louisiana is a hybrid with both the cash bonus amount and the royalty rate open to bid. In addition, companies may submit several bids on the same tract. Each bid is considered if it meets the minimum royalty rate of 12½ percent and any specified minimum bonus amount. In the 1980s, it is estimated that the average royalty rate has been 21 to 26 percent. The rental fee is set at one-half of the cash bonus amount for each tract. Louisiana has no corporate income tax, but has a severance tax of 12.5 percent on oil and 7 cents per cubic foot of gas.

California

From the start of leasing in 1929 through 1969, the State of California issued 62 offshore leases. A moratorium was placed on offshore leasing in 1969 as a result of the Santa Barbara Channel blowout. However, drilling on previously leased lands was allowed to continue and some leases were extended. The State is currently planning to resume leasing in the Point Conception/Point Arguello offshore areas, pending the settlement of jurisdictional questions with the California Coastal Commission. From the start of leasing through 1983, approximately 1.9 billion barrels of oil and 700 billion cubic feet of gas have been produced in the California offshore. This is far more than has been produced in Federal waters offshore the State, representing almost 90 percent of the total oil and gas produced off the coast of California to date.

California traditionally has awarded leases on the basis of a cash bonus bid with a sliding scale royalty rate, set at a minimum of 162/3 percent. It is estimated that the sliding scale royalty system has resulted in an overall effective royalty rate of 25 percent. Several other types of bidding systems are authorized by California regulations, and the State plans to experiment with net profit share payments in future lease sales. The other lease payment is an annual rental fee of not less than one dollar per acre, Taxes on offshore operators include a 9 percent corporate income tax, which is applicable to the worldwide income of the company. Although the State does not have a severance tax as such, it does levy a small fee on oil and gas production in order to finance offshore administrative and regulatory activities.

Texas

Texas issued its first offshore lease in 1922, drilled the first well in State waters in 1938, and recorded the first production in 1940. Until the 1980s, oil and gas production from State waters remained about equal with that from Federal waters offshore the State. However, oil production in Federal waters has now increased to about 90 percent of total oil produced offshore Texas, while Federal offshore natural gas production increased to 78 percent of the total in 1983. It is estimated that more than two-third's of the State's offshore area has been leased, and that State offshore oil and gas production will continue to decline. In 1983, approximately 2 million barrels of oil and 148 million cubic feet of gas were produced in State waters.

Texas holds lease sales twice a year and leases most offshore tracts by a cash bonus bid/fixed royalty bidding system. However, Texas also has used royalty bidding for 10 to 15 percent of its offshore tracts, primarily those where hydrocarbon prospects were high. In both types of bidding systems, the minimum royalty rate is now 25 percent, Texas also has a graduated rental fee system which increases with the number of years acreage is held, amounting to $1 per acre after the fourth year. The Texas severance tax consists of 4.6 percent on oil production and 7.5 percent on natural gas production, and there is also a small regulatory tax.

Alaska

Alaska issued its first State offshore leases in 1959. Unlike other States with offshore oil and gas production, Alaska has as yet no oil or gas production in Federal waters off the State. However, a probable commercial discovery was announced at Seal Island in the Beaufort Sea in 1984. In 1983, Alaska produced 22 million barrels of oil and 90 million cubic feet of gas from offshore State leases. Offshore gas production has continued to increase, while offshore oil production has declined since the 1970s. There is still substantial activity in State waters where 14 drilling platforms were stationed and 18 wells drilled in 1983, as compared to 3 structures in Federal waters in that year.

Prior to 1978, Alaska used the Federal bidding system of cash bonus bid and 16⅔ or 12½ percent royalty in leasing State offshore tracts. Amendments to Alaska's oil and gas leasing laws in 1978 broadened the State's bidding methods. Since 1978, Alaska has leased a greater number of tracts with sliding scale royalties as well as with profit share and royalty rate bidding. In addition, the minimum royalty rate was increased to 20 percent. This was due to concern about declining oil production and the desire to increase revenues from potentially large oil and gas discoveries, particularly downstream revenues. Alaska is one of the few States which collects more revenues from oil and gas production in the form of taxes than in the form of lease payments. These taxes include a corporate income tax, a property tax, and a severance tax, which increases from 12.5 percent to 15 percent of the value of oil and gas production after 5 years.

Foreign Offshore Leasing Policies

Comparison of U.S. and Foreign Systems

The offshore leasing systems used in other countries differ from that used in the United States. Canada, the United Kingdom, and Norway, as well as the United States, are currently leasing offshore tracts in high-risk, high-cost regions of the Arctic and the North Sea. These areas are characterized by harsh operating environments that require complex planning, long lead-times to first production, high capital outlays, and the use of innovative technologies. In the design of its leasing system for offshore frontier areas, the United States differs from these countries in several aspects (see table A-6).

ALLOCATION OF LEASE RIGHTS

The United States is one of the few countries to grant leases solely on the basis of financial competition. Most other countries rely on governmental discretion and industry-government negotiation to award lease rights. Foreign lease allocation is by subjective comparison of the qualifications and terms being offered by applicants. After negotiation with the firm, foreign governments may include stipulations in the leases to ensure rapid exploration and development of specified areas, provide for government participation in oil and gas production, protect the environment, provide for local employment, or further other national goals. While discretionary allocation provides greater scope for government influ-

Table A-6.—Comparison of United States and Foreign Offshore Leasing Policies

	United States	Canada	United Kingdom	Norway
Leasing Provisions				
Allocation	Competitive	Discretionary	Discretionary	Discretionary
Lease terms	5/10 years or as long as producing	Exploration: 5 years Production: 10 years, renewable for 10 years	Exploration: 3 years Production: 6 years, renewable for 40 years	Exploration: 3 years Production: 6 years, renewable for 30 years
Work program	None	Yes	Yes	Yes
Relinquishment	None	50 percent of acreage	Up to 2/3 of acreage	50 percent of acreage
Average tract size	25 sq. km	2000 sq. km	250 sq. km	550 sq. km
Financial Provisions				
Government participation	None	25 percent (optional)	None	>50 percent (optional)
Lease payments	Cash bonus, 12½% or 16²/s °/0 royalty	100/0 royalty, plus incremental royalty	12½% royalty (none for frontier areas)	Sliding scale royalties
Incentive payments	None	Up to 80% for Canadian firms, 25°/0 for foreign firms (exploration only)	None	None
Taxes	Corporate Tax: 46°/0 Windfall Profits Tax (except in Arctic)	Corporate Tax: 46°/0 Petroleum Revenue Tax: 12°/0	Corporate Tax: 52°/0 Petroleum Revenue Tax: 75°/0	Corporate Tax: 50.8°/0 Special Petroleum Tax: 35°/0

SOURCE: Office of Technology Assessment.

ence than competitive bidding, it is also more expensive to administer.

LEASE STAGES

The United States is unique in jointly granting leases for offshore exploration and development. Other countries make a greater distinction between exploration and development lease rights. In these countries, exploration leases are granted for large areas for terms of 3 to 5 years, specify the work to be completed, and require that all data be shared with the government. If a discovery is made, the terms of a production lease are then negotiated. The advantage of the two-stage system is that it provides for rapid exploration of large offshore areas and gives the government greater flexibility in establishing production lease terms.

WORK PROGRAMS

In the United States, lease rights are obtained through the payment of upfront bonuses, which provide an incentive for firms to engage in efficient exploration and development so as to recover the initial investment. The U.S. government only requires the submission of exploration and development plans and diligent exploration. The discretionary allocation method used by other countries usually entails a mandatory work program negotiated in conjunction with the lease rights. This may consist of detailed exploration and development plans, drilling of a certain number of wells, and/or a minimum expenditure. Firms which fail to carry out the terms of the work program can lose lease rights or any collateral paid to the government. Work commitments ensure rapid exploration and development, but also can be expensive to administer.

RELINQUISHMENT

Other countries usually have relinquishment requirements for nonproductive acreage in conjunction with much larger tract sizes. Canada, the United Kingdom, and Norway have stipulations in their exploration and/or production leases that firms relinquish, at specified times, a certain percentage of their tracts. This requirement forces companies to explore rapidly to determine the most premising acreage for further exploration and development. In addition, the initial tracts leased for exploration are 10 to 80 times larger than tracts in the United States, which are limited to 25 square kilometers. The United States has an indirect incentive for relinquishment of nonproductive acreage in its tax system, which allows companies to write off expenses related to dry holes or nonproductive tracts.

FINANCIAL PROVISIONS

The United States relies primarily on lease payments for government income from offshore oil and gas development. In Canada, the United Kingdom, and Norway, the primary revenue source is government participation and/or taxation. The United States is also one of the few countries to require an upfront cash bonus payment for lease rights, rather than stretching out all lease payments over the life of the field. The United States uses a fixed royalty on production, rather than a sliding scale or incremental royalty linked to field productivity. The United States, like other countries, gives some incentive to exploration through its tax system, but does not offer direct exploration subsidies as does Canada.

Foreign Leasing Systems

CANADA

Canada began offshore leasing in the late 1950s and initiated leasing in the frontier Arctic areas (with as yet no production) in the 1960s. After the introduction of the National Energy Program in 1980, these leases were renegotiatied into exploration agreements and over a hundred new agreements were entered into for exploration in frontier *areas. In* recent years, Canada's offshore leasing program has been focused on rapid exploration and development of resources, achievement of national energy self-sufficiency, and increased government participation in the oil and gas industry. Since the 1984 national elections, the offshore leasing and financial terms have been under government review.

Canada has a two-stage leasing system, where exploration and production licenses are granted separately and different procedures govern each. Exploration agreements are made on a discretionary basis, usually with provisions for work commitments. They are granted for large areas, averaging 2000 square kilometers, and include measures for relinquishment of 50 percent of the acreage at the end of the initial 5-year term. The remaining lease area may be retained by renegotiating the exploration agreement. Production licenses may be obtained by lessees at any time and are renewable in 10-year increments.

Since 1980, Canada has increased government participation in oil and gas development and enacted an exploration subsidy program which favors Canadian-owned firms. The Canadian national oil company, Petro-Canada, has the right to a 25 percent working interest in any commercial discovery on offshore tracts. The Petroleum Incentives Program initiated in 1982 reimburses Canadian-owned companies for up to 80 percent and foreign companies for up to 25 percent of eligible exploration costs. This program replaced the favorable "superdepletion" provisions allowed against the Corporate Income Tax, which still allows the immediate deduction of both tangible and intangible drilling costs. In addition, Canada has a Petroleum and Gas Revenue Tax levied since 1981 at an effective rate of 12 percent on gross income. Together with a fixed 10 percent royalty, this tax makes the Canadian revenue system on offshore fields somewhat regressive. Canada also has a progressive incremental royalty on net income from offshore production.

UNITED KINGDOM

The United Kingdom has leased offshore tracts since the mid-1960s, but leasing in the northern North Sea tracts did not begin until the early 1970s. The United Kingdom has relied on frequent adjustments to a complicated tax system to influence the level of offshore activity and the flow of government revenues. In 1983, the financial terms for offshore leasing were liberalized to encourage exploration in frontier areas and the development of marginal fields.

The United Kingdom has held eight oil and gas ''leasing rounds, each characterized by different leasing and financial provisions. The government has generally used a discretionary system for offshore leasing, but has experimented with competitive bidding and offered 15 North Sea blocks for cash bonus bids in the eighth leasing round in 1982-83. Exploration licenses are granted for periods of 3 years and specify a schedule of geological and geophysical surveys and well drilling. All data are to be relinquished to the government. Production licenses also involve negotiated work programs and are granted for initial terms of 6 years. Tracts are ten times larger than those in the United States, averaging 250 square kilometers in size, but up to two-thirds of the tract must be relinquished at the end of the initial term.

The United Kingdom traditionally has relied on government participation and taxation for the major share of revenues from offshore leasing. However, companies no longer have to take the British National Oil Corporation as a partner in offshore development, although some licensing preference is still given to groups which include government participation. In 1983, the government changed the lease terms and tax provisions to spur offshore exploration and development. Royalties were eliminated for northern North Sea fields, although a 12½ percent production royalty is still charged for other areas. Firms now may recover all exploration and development costs prior to paying the Petroleum Revenue Tax, which is field specific. They also receive special allowances for small fields. In addition, the Corporation Tax, which is "ringfenced" to offshore fields, is being decreased gradually from a rate of 52 percent to 35 percent in 1986-87.

NORWAY

Norway began offshore leasing after the passage of the Continental Shelf Act of 1963, and oil from North Sea areas is now being produced under some of the most difficult operating conditions in the world. Leasing policy has changed emphasis from encouraging rapid exploration and development to increasing government returns from oil and gas development. Norway gains substantial income from offshore hydrocarbon production from an excess profits tax and a requirement that at least a 50 percent equity interest in every tract be given to the Norwegian State Oil Company, Statoil.

Norway uses a discretionary, two-stage system for allocating lease rights, with initial exploration licenses granted for large offshore areas. The licenses are for periods up to 3 years and contain provisions for data-sharing with the government. Production licenses with mandatory work programs are valid for initial terms of 6 years for initial tracts averaging 550 square kilometers. Production licenses can be renewed for an additional 30 years for 50 percent of the original area.

The Norwegian government obtains oil and gas revenues from state participation, taxation, and moderate royalties on production. Since 1972, Statoil has had at least 50 percent equity in all production licenses and has been appointed operator for more than one-third of these licenses. Norway has a Corporate Tax and also a Special Petroleum Tax on net income. The Special Petroleum Tax is calculated on the basis of total offshore operations, and unlike the British Petroleum Revenue Tax, does not contain any exemptions for small fields. As a result, the Norwegian marginal tax rate is extremely high for all fields and has caused Norwegian authorities to undertake a review of the current tax system. In addition, Norway has a system of sliding scale royalties on petroleum production and a flat 12½ percent royalty on natural gas.