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EFFECTS OF OFFSHORE OIL AND NATURAL GAS DEVELOPMENT ON THE COASTAL ZONE

A STUDY

PREPARED PURSUANT TO THE REQUEST OF

Hon. John M. Murphy, Chairman

FOR THE USE OF THE

AD HOC SELECT COMMITTEE ON OUTER CONTINENTAL SHELF HOUSE OF REPRESENTATIVES

BY

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LETTER OF SUBMITTAL

LIBRARY OF CONGRESS,
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Washington, D.C., January 8, 1976.

Hon. JOHN M. MURPHY,
Chairman, Ad Hoc Select Committee on the Outer Continental Shelf, U.S. House of Representatives, Washington, D.C.

DEAR MR. MURPHY: In response to your request, we are submitting a study on onshore effects of offshore oil and gas development.

The report includes an evaluation of the Nation's offshore oil and gas resources, and the projected environmental and socio-economic effects of petroleum development offshore as well as onshore. Other chapters discuss questions of ownership of the resources, current government OCS development regulations, congressional actions aimed at changing current regulations, and compensation to the coastal States.

The study was conducted by James W. Curlin, Thomas E. Kane, Mark H. Zilberberg, and Herman T. Franssen of our Ocean and Coastal Resources Project; Joseph P. Riva, Jr. and James E. Mielke of the Science Policy Research Division; and Maureen B. McBreen of the Economics Division of the Congressional Research Service. Herman T. Franssen coordinated the project and edited the contributions.

We hope that this study will serve your committee's needs as well as those of other committees and Members of Congress interested in ocean affairs and coastal zone management.

Sincerely,

NORMAN BECKMAN,
Acting Director, Congressional Research Service.

LETTER OF TRANSMITTAL

U.S. House of Representatives,
Ad Hoc Select Committee on Outer Continental Shelf,
Washington, D.C., March 31, 1976.

To: Members of the Ad Hoc Select Committee on Outer Continental Shelf:

I am pleased to transmit herewith for your information and use, a study undertaken by the Congressional Research Service of the Library of Congress, entitled: Effects of Offshore Oil and Natural Gas Development on the Coastal Zone.

The study highlights every one of the important aspects of outer continental shelf oil and natural gas developments, and the impacts those developments will have on the ocean environment and coastal zone.

The importance of the energy resources of the outer continental shelf to meet the short-term and intermediate-term energy future of our Nation, cannot be overemphasized. Last year the United States imported approximately 37% of its total oil consumption, or 6 million barrels per day. This year imports are likely to rise to about 7.5 million barrels per day, or more than 40% of our total oil consumption.

If we can develop the energy resources of the outer continental shelf, we can reverse the trend towards increasing imports. The outer continental shelf has vast oil and natural gas resources, which could benefit the Nation for several more decades, until alternative sources of energy have been developed.

This study by the Congressional Research Service indicates that offshore oil and gas can be developed in an environmentally responsible way, and provided onshore impacts are carefully planned, adverse socio-economic impacts can be minimized.

While I am not prepared to certify the validity of all the conclusions reached by the research team of the Congressional Research Service, nevertheless, I believe that the study is an important contribution to our knowledge of environmental and socio-economic impacts related to offshore oil and natural gas developments.

Sincerely,

John M. Murphy,
Chairman, Ad Hoc Select Committee on Outer Continental Shelf.

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FINDINGS

OUTER CONTINENTAL SHELF ENVIRO

OCS operations are environmentally sound

1. Most oil pollution in the oceans comes from vessels, especially tankers, and from waste oil in municipal and industrial effluents. A five-percent reduction in oil pollution from either of these sources would have a more positive impact on the marine environment than elimination of *all* offshore production. Transportation (tankers primarily) contributes an estimated 35 percent of all ocean oil pollution. River and urban runoff contributes 31 percent, and offshore production 1.3 percent.

2. Based on experience to date and the probability of spills, offshore OCS production will be less damaging to the environment than importing a like amount of petroleum. From a worldwide perspective, OCS development off the United States is preferable to similar development in many areas of the world where environmental standards are less strict.

3. Onshore environmental impacts from OCS development should not be significant, provided careful planning is done and effective emission and effluent control technilogies are used.

Oil spills not major problem

4. Large spills from OCS operations are less of a problem than smaller, more frequent spills and chronic discharges. Chronic small spills could produce long-term ecological impacts. Local impacts from a large spill might be quite severe, but most indications are that the major effects are short-term in nature. The marine environment is resilient and has the ability to absorb oil spill impacts through natural processes. Additional research on possible long-term impacts is needed.

5. Marine organism primarily take up petroleum hydrocarbons directly from water and sediments. There appears to be no magnification of these hydrocarbons through the food chain.

6. Recent advances in oil spill containment and clean-up technology have been impressive, but the only sure method of protecting the environment is to prevent spills from OCS fixtures.

7. There is no evidence to date that coastal fisheries have been adversely affected by offshore oil operations. Suggestions that the Louisiana oyster harvest has declined are not borne out by National Marine Fisheries Service statistics. Sport fishing has benefitted from the installation of offshore platforms in the Gulf of Mexico which serve as attractions for fish. Coastal fisheries survived the 1969 Santa Barbara oil spill.

8. Baseline studies are valuable in determining the relative risks of developing OSC areas, but extensive baseline data gathering is of less utility because of seasonal fluctuations. Concurrent monitoring

of OSC development areas and nearby undeveloped areas is needed to determine the impact on the marine environment from OCS production.

OUTER CONTINENTAL SHELF RESOURCES

OCS best U.S. prospect

9. The U.S. continental shelf can be the largest domestic source of oil and gas between now and the 1990's. The chances of finding large new fields on U.S. land are slim, except in Alaska.

10. Even if the high projections of offshore oil and gas resources are realized, the nation will still require major amounts of oil and gas from foreign sources.

Leasing slowed

11. The pace of OCS exploration has been slowed dramatically from earlier projections. From the proposed ten-million acre sale objective in 1975, there evolved a three-million acre goal. In fact, 1.7 million acres of OCS territory was leased. Bonus money paid by industry was only twenty percent of the amount received in 1974. Although six OCS sales are scheduled for 1976, only four appear likely.

SOCIO-ECONOMIC IMPACTS

Onshore impacts may be major locally, minor overall

12. With the exception of Alaska, the direct overall regional impact from introducing OCS operations into frontier areas will be relatively modest in terms of added population and employment. Secondary impacts attracted by new sources of petroleum could alter this picture. On the other hand, small communities, especially in rural areas, may undergo major impacts from the influx of people to service the offshore industry. Careful planning is absolutely necessary in such areas to minimize the adverse socio-economic impacts on rural lifestyles, as well as in areas with significant environmental, historic, cultural or aesthetic values.

Communities face public expenditures

13. Local communities will have to provide public facilities and services made necessary by the added employment involved with offshore activity. These might include schools, roads, health facilities, recreational opportunities, sewage treatment plants, or police and fire protection. Because small comumnities, and in some cases larger ones, will have difficulty raising the funds needed to provide such facilities and services in advance of the time tax revenues might grow as a result of the industry and its secondary effects, Congress is considering various types of OCS impact aid. All receipts from OCS royalties and bonus bids go to the federal treasury while costs are borne locally. Also, operations will be shut down after fields are depleted, which would cause additional socio-economic disruption.

Onshore impacts difficult to project

14. Little scientific data are available on the onshore, environmental and socio-economic impacts in Louisiana and Texas, where over 90 percent of the nation's OCS production to date has taken place.

15. Projections of the impacts which would be felt in frontier areas have been revised downward. Early projections prepared by the Council on Environmental Quality and other sources have been supplanted by more recent reports by such sources as the Bureau of Land Management, which suggest employment and population impacts viewed from the standpoint of overall regional economies will be fairly modest.

16. The generation of secondary industrial and commercial activity as a consequence of introducing OCS operations into new areas has not been considered in this study. Data on this phenomenon are also lacking. While it seems clear that in some areas, new OCS fields will stimulate major secondary industrial expansion and considerable socioeconomic and environmental impacts, it is beyond the scope of this report to try to project same.

17. It does not necessarily follow that major new installations by the offshore service industry wil take place along the Atlantic and in other new or expanded areas of OCS leasing. Existing industry will be able to service the new fields to a major extent. Drilling rig and platform construction yards may be located near new fields in some areas.

18. Aesthetic impacts from offshore operations is a problem in a populated area such as southern California where platforms are located close to shore. Less concern is expressed in the Gulf of Mexico where adjoining land areas are rural. Offshore equipment will be located out of sight of New England and Mid-Atlantic areas. Southern Atlantic and Alaskan areas may have equipment near shore, but adjoining areas are largely rural.

19. Onshore development associated with the OCS industry do not necessarily have to be located in the coastal zone. Onshore facilities, as has been demonstrated in England, may be located well away from the coast to avoid the concerns about damaging the coastal areas and the serious use conflicts which take place there. This experience may be a useful guide to frontier OCS areas in this country.

NEW LEGISLATION

OCS Act being revised

20. The OCS Lands Act of 1953 has proven adequate for the nation's experience to date with offshore leasing. In view of the need to accelerate OCS leasing into frontier areas, some without previous experience with the petroleum industry (or any heavy industry at all in some instances), changes to the OCS Lands Act are being considered in Congress. Included are:

(*a*) Revision of the current bonus bidding system to provide several new leasing options for the Secretary of the Interior. The aim of the revisions is to allow more competition and to provide for the maximum return to the treasury;

(*b*) Provision that the federal government may conduct exploratory drilling in an attempt to obtain directly information about the nature and extent of new offshore fields;

(*c*) Separating the exploration and field development phases of OCS activity;

(*d*) Providing assistance to states and local communities impacted by OCS operations in the form of loans, grants or bond guarantees. Impact assistance would variously be allocated according to the extent of OCS activity adjoining a state or a demonstration that public expenditures are not covered by added tax revenues. Similar additions to the Coastal Zone Management Act of 1972 are being considered.

(*e*) Providing greater responsibility of OCS lease holders for oil spill damages and imposition of strict liability.

Executive Summary

In an address to a meeting of Governors on OCS oil and gas development on Nov. 13, 1974, President Ford emphasized the importance of OCS oil and gas for the future of the Nation's energy supply. He said:

> The outer continental shelf oil and gas deposits can provide the largest single source of increased domestic energy during the years when we need it most. . . . We must proceed with the program that is designed to develop these resources.[1]

President Ford has essentially continued the OCS policy of the Nixon administration in a somewhat modified version. President Nixon outlined on January 23, 1974, an extensive legislative and regulatory program which he urged Congress and the Executive agencies to act upon within the year. Part of the Presidential program related to the outer continental shelf. President Nixon announced that he had directed the Secretary of the Interior to increase the acreage leased on the OCS to 10 million acres beginning in 1975, more than tripling what had originally been planned.[2] In later years the amount of acreage to be leased would have been based on market needs and on the industry's performance record in exploring and developing leases.

The ten million acres lease sale would have been almost equal to all OCS lease sales between 1954 and 1974.[3] Many observers doubted that rigs and equipment would be available to offshore operators to meet such a challenge.[4] Moreover, the very size of the accelerated OCS program proposed by the executive branch caused many observers to wonder if under the current bonus bidding leasing system for the OCS, corporations would not have to spread their capital available for lease sales so thin, that the American people—the owner of OCS resources—would receive less than a fair return for the companies' right to produce and market OCS oil and gas.

The Interior Department had to abandon the 10 million acre lease sales plan early in 1975 when it became clear that oil companies could not handle that much acreage, and thus were not likely to offer acceptable bids for available tracts and because of widespread opposition from congressional, state and local leaders. A lease sale held in January 1975 in the Gulf of Mexico off the South Texas coast resulted

[1] Address to meeting of Governors on OCS Oil and Gas Developments 10 Weekly Compilation of Presidential Documents 1440 (November 13, 1974).
[2] Ibid. p. 10.
[3] U.S. Dept. of the Interior. Geological Survey. *Outer Continental Shelf Statistics. 1953 through 1974*. Washington, D.C. June 1975. p. 19.
[4] U.S. Senate. Committee on Commerce. National Ocean Policy Study. *Outer Continental Shelf Oil and Gas Development and the Coastal Zone*. Washington, D.C. 1974. p. 94.

in sales of only about one-fifth of the 3-million acreage being offered. Parts of the Gulf of Mexico began to look less favorable for commercial hydrocarbon finds, especially after a group headed by Exxon drilled a number of dry holes in the Destin anticline, which was considered one of the very best prospects in the eastern Gulf of Mexico.

In addition to the three million acres offered off South Texas, the Interior Department intended to offer another three million acres in the Central Gulf of Mexico. In view of the declining prospects in that extensively developed area, Interior's expectations for major lease sales in the Gulf of Mexico in 1975 were scaled down substantially.

Projected lease sales in Cook Inlet, Alaska, and the Baltimore Canyon off the Mid-Atlantic States, were delayed pending Supreme Court decisions, and the proposed lease sale of OCS lands in Southern California was reduced to about one-fifth of the originally planned 1.5 million acres.

In its final Environmental Statement on the proposed increase in oil and gas leasing on the Outer Continental Shelf, published on July 7, 1975, the Bureau of Land Management stated: "It is entirely possible that no more than three million acres will be leased in 1975, even assuming that all six proposed sales are held.[5]

In fact four lease sales were held (five were planned); 1,679,877 acres were leased and bonuses totaled just over one billion dollars.[6] Hence, in spite of the Bureau's projections of early 1975, total acreage leased in 1975 was lower than in 1974 and only slightly higher than in 1973.

TABLE 1

Date of lease sale and OCS area	Acreage	Bonus bid
February 1975, Texas	626,585	274,690,955
May 1975, Texas, Louisiana	406,942	232,916,050
July 1975, Texas, Louisiana	336,301	163,214,006
December 1975, Southern California	310,049	417,312,100
Total U.S.A	1,679,877	1,088,133,111

Government bonus receipts in 1975 were the lowest since 1971, or equal to about 20% of the 1974 bonus payments.[7] Bonus receipts have been very disappointing in 1975. The Department of the Interior had expected that the Southern California lease sale alone would bring in between one and two billion dollars.

It is too early to project the amount of acreage to be leased in 1976. The proposed OCS Planning Schedule calls for six lease sales in 1976; two in the Gulf of Mexico, one in Gulf of Alaska, and one each in the North, South and Mid-Atlantic. In fact, it is not very likely that more than four lease sales will take place: two in the Gulf of Mexico, one in Alaska and one in the Mid-Atlantic.

OCS OIL AND GAS RESOURCES

The seabed is divided into four distinct areas: the continental shelf, continental slope, continental rise and the abyssal plain or deep-sea-

[5] *Final Environmental Statement, Vol. I, Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf*, July 7, 1975, p. 14.
[6] Bureau of Land Management, Jan. 1976.
[7] U.S. Department of the Interior, Geological Survey. *Outer Continental Shelf Statistics*, pp. 17, 18.

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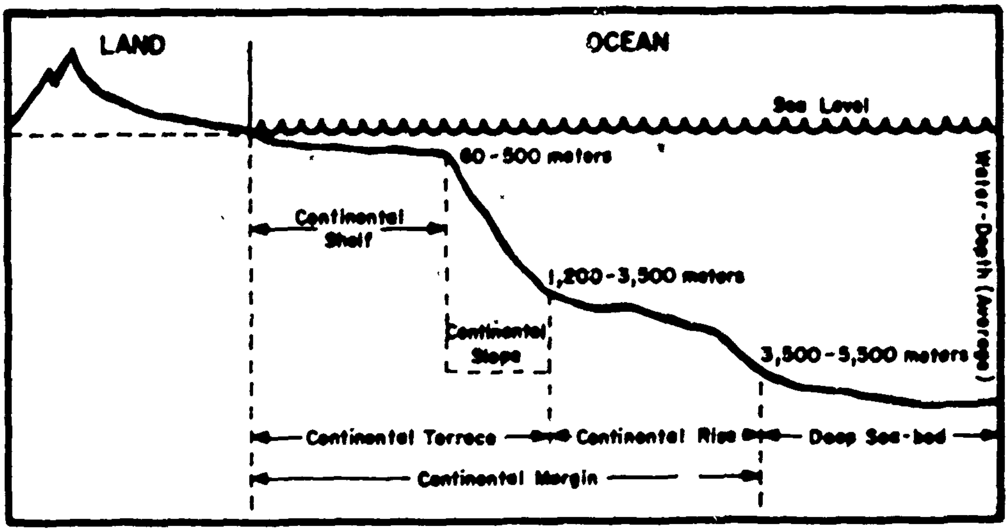
bed. The shelf, slope, and rise, although deeply submerged, are part of the Continental mass.

PROFILE OF CONTINENTAL MARGIN



Source: Herman T. Franssen, "Oil and Gas in the Oceans", *Naval War College Review*, May–June, 1974, p. 51.

Of the different parts of the seabed the continental shelves are considered to have the best potential for oil and gas accumulation. Continental shelves vary greatly in width, thickness of sedimentation and in stratigraphic and structural features which trap the migrating oil and gas.

Continental slopes are still largely a mystery, and except for the upper slopes, are generally not considered very favorable for petroleum accumulation. Many geologists believe that the landward side of the continental rise may contain substantial oil deposits. In U.S.G.S. statistics quoted here and elsewhere, ultimate recoverable oil that may be located beneath the continental rise has not been included. Areas beyond the continental rise are generally not considered favorable for oil and gas accumulation, but there are exceptions in small oceanic basins such as the Gulf of Mexico, where an oil occurrence was discovered by the R/V Glomar Challenger in waters of 11,720 feet.

Four segments of the U.S. continental shelf are generally regarded as either presently or potentially sources of oil and natural gas. These areas are: 1) the Alaskan continental shelf, consisting of the Gulf of Alaska, the Bering Sea, the Chukchi Sea, the Beaufort Sea, and Prudhoe Bay; 2) the Gulf of Mexico, including areas off the coast of Texas, Louisiana, Mississippi, Alabama and Florida; 3) the Pacific Shelf, including the Santa Barbara Channel and the Southern California basins as well as offshore Oregon and Washington; 4) and, the Atlantic Shelf, including the Georges Bank off New England, the Baltimore Canyon off New Jersey, Delaware and Maryland, the Southeast Georgia Embayment from South Carolina to Florida, and the Blake Plateau off northern Florida and Georgia.

RESERVES AND RESOURCES

U.S. petroleum resources can be divided into two basic groups: Demonstrated reserves, and undiscovered recoverable resources. Demonstrated reserves are those which geologic and engineering knowledge indicate, with reasonable certainty, to be recoverable from known reservoirs under existing economic and operating conditions. In the United States, this averages at about one-third of the oil in place (the volume of oil known to exist in all reservoirs). There are a number of methods in use to estimate undiscovered recoverable resources. Some are based on the premise that a given volume or area of sediments in a basin which is favorable for hydrocarbon generation and entrapment should ultimately yield a predictable volume of hydrocarbons.[8]

Others include geologic parameter analysis, production and reserve data analysis, and discovery index analysis.

Assessments of undiscovered potential resources of oil and gas are educated guesses, useful only in providing information on worthwhile exploration areas. Areas of the seabed which appear favorable for oil and gas formation and entrapment must be put to the test of the drill in order to prove that oil and/or natural gas can be produced in commercially attractive quantities.

TABLE 2.—U.S. OFFSHORE OIL AND NATURAL GAS RESERVES AND RESOURCES

	Demonstrated Reserves		Undiscovered recoverable resources		
	Oil (billions cubic feet)	Gas (trillion cubic feet)	Oil (billions of barrels)	Gas (trillion cubic feet)	Gas liquids (billion of barrels)
Alaska	0.150	0.145	3–31	8–80	1.1
Pacific	1.116	.463	2–5	2–6	.1
Gulf of Mexico	2.262	35.348	3–8	18–91	1.3
Atlantic			0–6	0–22	.3
Total	3.528	35.956	8–50	28–199	2.8
Statistical mean			26	107	

Note: Undiscovered potential resources of oil, gas, and liquid gas have been estimated to range from 95 percent to 5 percent probability for all areas.

Source: U.S. Department of the Interior, Geological Survey. The undiscovered potential resources estimates are for seabed area to a depth of 200 meters. Potential oil and gas from the continental slope and rise are not included in the estimates.

OCS OIL AND GAS PRODUCTION

The Gulf of Mexico is the primary source of offshore oil and gas, producing approximately 390 million barrels out of a total U.S. offshore oil production of about 533 million barrels in 1974. The Gulf area also produced more than 95% of the Nation's offshore natural gas production in 1974.[9] The Southern California lease sale of December 1975, and the proposed Atlantic and Alaska lease sales for 1976–1978 are likely to gradually alter the almost complete reliance on the Gulf of Mexico for offshore oil and gas production. By the early 1980's, first California, and later the Atlantic, are likely to contribute a significant percentage of offshore petroleum production, but ultimately the State

[8] See: Herman T. Franssen, "Oil and Gas in the Oceans", Naval War College Review, Vol. XXVI, Number 6, May–June, 1974, p. 52.
[9] *Outer Continental Shelf Statistics*, op. cit. pp. 87 and 88.

of Alaska is likely to become the leader in the Nation's offshore oil and gas production.[10]

Offshore oil production, which now comprises about 15% of total domestic oil production will probably grow in importance. Some studies have indicated that total offshore production may comprise between 25 and 30% of total U.S. oil production by 1985.[11] Total oil production from onshore fields in the lower 48 States and offshore fields in producing areas is likely to continue to decline. That does not mean that there is no oil left to be found in those areas, but the chances of finding large new fields in these older provinces are small. Only five fields of over 100 million barrels of oil (or gas equivalent) have been found onshore in the lower 48 States by the 38,000 exploratory wells drilled in the last five years. The attractiveness of the OCS is the possibility that it may yield oil in larger accumulations and in this sense, the oil may be found and translated to large production sooner than in the picked over provinces onshore. Many geologists now believe that total conventional oil production in the United States is likely to come to a final peak in the early 1990's, after which production will again decline.

OCS LEASING AND MANAGEMENT

The mineral resources of the OCS come under the purview of the OCS Lands Act of 1953. Pursuant to this law, the Secretary of the Department of the Interior is empowered to issue permits and lease tracts on the OCS to private interests which are then authorized to explore and extract the mineral resources found there. The Secretary may condition such authorization and can regulate activity associated with them. No mineral exploration or extraction may be carried out in the OCS adjacent to the U.S. beyond the 3-mile territorial limit without the necessary approval from the Secretary. Other major legislation with major impact on OCS development are the 1969 National Environmental Policy Act, the 1972 Coastal Zone Management Act and the Federal Water Pollution Control Act Amendments of 1972. There are a number of other laws which are specifically referred to in the OCS Lands Act being applicable to activities carried out under the Act. Therefore, when looking at the OCS Lands Act, it is important not to look at it in isolation, but rather to view it in light of other applicable laws.

Under the current leasing system, the Secretary of the Interior may lease tracts on the OCS to the highest responsible qualified bidder through competitive bidding. The OCS Lands Act of 1953 authorizes the Secretary to hold the bidding on the basis of either a cash bonus bid with a fixed royalty (not less than 12.5%), or a royalty bid (not less than 12.5%) with a fixed cash bonus. The latter has only been tried once. Also, the Secretary is authorized to set a rental fee at the time of the lease. The actual leasing process entails the following chronology: environmental baseline studies, resources evaluation, call

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[10] See Table.

[11] U.S. Congress. Joint Committee on Atomic Energy. *Towards Project Interdependence: Energy in the Coming Decade*. 94th Congress. 1st Session. Washington, D.C., December 1975, p. 35.

for nominations, tract selections, environmental impact statement, and finally the lease sale. The decision of whether to accept or reject the highest bid is based on a post-sale evaluation, which includes a resource evaluation conducted by the U.S. Geological Survey and carried out during the period after the announcement of the tract selections and during the preparation of the environmental impact statement. The resource evaluation entails an analysis and estimate of the resource potential of specific tracts. Of course, there is no way of knowing exactly how much oil and gas (if any) is located in each tract. Geologists of the U.S.G.S. and those of interested private parties, make their evalution based on their own interpretation of seismic data available to both the U.S.G.S. and the industry. The difference in interpretation of seismic data translates into different evaluations of the commercial value of the tract.

Lessees can proceed with their exploratory program after the lease sale, but they have to follow a complex set of specific OCS Orders issued by the U.S.G.S. Once oil or gas is discovered in commercial quantities and the lessee desires to produce it, the lessee must file a development plan with the supervisor prior to commencing development.

There has been criticism of the 22-year-old OCS Lands Act, and several bills are pending in Congress which focus on changes in the 1953 OCS Lands Act. Legislation introduced in Congress would revise the current bidding system, providing the Secretary of the Interior with several new leasing options such as: variations on the bonus bidding system and royalty system, profit sharing and leasing on the basis of a percentage of working interests. The proposed changes are designed to reduce front-end bonus costs and thereby make more money available for exploration. They would also further facilitate small company participation in OCS development, and will, according to some observers, provide the public with a higher return to publicly owned resources. The oil industry, the Department of the Interior, and some independent academicians, however, maintain that so far net returns on OCS investments for oil and gas developments have averaged between 5 and 6%, and thus the public has received more than a fair share of the total income from offshore oil and gas development. Most oil companies maintain that they still prefer the current bonus bidding system over the new proposed alternative leasing systems, because they believe that with the application of the most advanced technology, they (the individual companies) will perform better (in terms of profits) than the industry average would indicate.

The prime reason the proponents of alternative leasing systems want a range of alternative leasing systems to choose from is to find out through experimentation with the various systems, which system will evolve as the best.

One of the more controversial proposals included in the pending legislation is the provision that would allow the Federal Government to conduct, either on its own or by contract, exploration in the OCS. The argument for this provision is that the Government needs more information on oil and gas potential in order to insure that the public receives a fair market return for its mineral resources (perhaps higher if oil and gas are found, and lower if they are not). An extensive exploration program may accomplish this. However, opponents maintain that to find out the location and quantity of oil and gas that is located beneath sections of the seabed, would involve a vast program not only of seismic surveys but also of exploratory drilling. Experiences in the North Sea and in the Gulf of Mexico have indicated that it often takes scores of dry holes before oil and gas is found. Would the Federal Government be willing to spend tens of millions of taxpayers' dollars to test promising structures? What will the Federal Government do if tens of dry holes indicate that the likelihood of finding oil in a specific structure appears small? Will they abandon the effort, or will they continue the drilling program? Opponents also argue that the Government is much less qualified to search for OCS oil because it lacks the experience to conduct such activities. Proponents, in turn, maintain that the Government can simply pay private companies to handle the actual mechanics of the Federal exploration program, and if the Government were to decide to form a Government owned company, it would hire oil company personnel in the same fashion as other governments around the world have done (with varying degrees of success).

Many States and environmental groups have advocated that exploration of the OCS should be separated from the subsequent development and production phases. The reasoning is that prior to exploration, it is not known what resources are present; and, therefore, there is no assurance that the environmental impact statement which was drafted prior to the lease sale will be adequate in light of the actual experiences of exploration and production. The States have only the estimates of potential resources to use in the preparation of the resulting onshore impacts, which may vary greatly from the resources discovered during exploration. Moreover, due to experiences of exploration activities, it may prove to be undesirable to continue with development and production of certain parts of the OCS. Under existing law, there is no way to terminate the lease or to prohibit further activity unless the terms of the lease are violated.

Opponents maintain that separation of exploration and development would be unpractical because the various steps from seismic surveys to production are an expensive and gradual process that cannot be broken up easily. Moreover, it would introduce a great deal of uncertainty for oil companies which would not know in advance whether they would be able to develop their discoveries. How would the corporations be reimbursed for exploration costs should the Government decide that development would not be in the national interest? The new proposals also include references to Federal-State cooperation, not to give States veto power, but to give them as much input into the process giving their concerns every consideration and where possible incorporating them into the Secretary's decision.

Legislation pending before Congress would also toughen the responsibility of the lessees for oil pollution and impose strict liability under the OCS Act. Finally, States would receive Federal assistance in the form of grants and loans for adverse impacts, automatic grants based on an amount per barrel of oil and gas landed in or produced adjacent to a coastal State, or bond guarantees by the Federal Government for local or State bonds or other evidences of indebtedness. These forms of assistance would be provided to the States in recognition of the legitimate concerns of the States while at the same time taking into consideration the national interest in finding and producing more energy for the Nation.

OFFSHORE ENVIRONMENTAL IMPACT

It is generally recognized that the accidental release of oil into the marine environment represents, from an ecological viewpoint, the most critical OCS event. To monitor the effects of oil spills in the environment, baseline studies of potential lease sale areas need to be made. A reasonably large body of information on the effects of oil spills on the environment already exists, but much of the information is based on laboratory studies under controlled conditions that may in some cases not be completely applicable to natural environments.

There is no conclusive evidence on the long-term effects of a major oil spill on the marine environment, but it is known that short-term damage from a large spill is undeniably severe. However, the effects of oil spills on marine life need to be compared with natural calamity caused by changes in salinity, temperature, oxygen level,-and the buildup of poisonous materials or gasses. According to a report by the National Academy of Sciences, these natural occurrences, causing variations in species composition, make it difficult to detect in the field changes caused by petroleum additions. If multiple natural occurrences coincide with an oil spill (as occurred at Santa Barbara), separation of the effects of petroleum becomes difficult. These findings were confirmed by an inter-disciplinary group of 23 principal investigators at 20 universities in the Gulf of Mexico region.

Dr. Lyle St. Amant, Assistant Director for Marine Fisheries and Coastal Management at the Louisiana Wildlife and Fisheries Commission maintains that 38 years of experience with offshore oil production in Louisiana, has indicated that the toxic effect of oil to a large extent has been exaggerated and animal, plant, and fish kills are negligible.

Some opponents of offshore oil development maintain that baseline studies of the ocean environment need to be made prior to leasing. Many investigators, on the other hand, consider the normal time lag of three years or more between the lease sale and the time development begins adequate for gathering sufficient baseline data, assuming a reasonable effort is funded.

Every oil spill will not have the same impact on the environment. Several factors influence the extent of the ecological impact. Among the more important of these factors are: the dosage of oil an ecosystem receives; the physical and chemical nature of the oil spill, including the effects of weathering; the climatic conditions and locations where the spill occurs; the time of the year of a spill; the prevailing oceanographic and meteorological conditions; and, the techniques used to clean up the spill. In general, large spills are much less likely to occur than small spills. Frequent small spills in an area could produce long-term ecological effects. If a large spill should occur, the local impact may be severe, but most indications are that the major effects would be fairly short term. The marine environment has the resiliancy to recover from an oil spill and most of the spilled oil would be consumed within the ecological system.

In the offshore oil development process exploratory drilling is one of the most hazardous steps. The hazard potential is greatest when drilling into an unknown formation because of the possibility of encountering an unexpected, sudden surge of pressure up the drill hole causing a blowout or loss of well control. Most blowouts involve only gas which is of course less environmentally damaging if released than oil. Accumulations of drilling mud (most is recovered but some is lost in the drilling process) could produce harmful results to marine life in the immediate vicinity of the rig, but this impact is said to be insignificant compared to smothering of organisms due to natural shifts of sediments from storms, currents, etc. Spills can also occur during field development and production stages. Spillage can either be the result of normal operations or natural forces, such as hurricanes or storm waves. Of the more than 3,000 offshore platforms in the U.S., however, less than one percent had foundered in the past 25 years. More recently, one of the most severe storms in a hundred years in the North Sea (a sea known for its frequent bad weather conditions) did not affect the drilling and production facilities located offshore. The oil industry has made remarkable progress in recent years in designing and testing equipment to meet special potential hazards such as earthquakes in Southern California and moving pack ice in Alaska.

Of great significance are the blowout preventers, which consist of a series of control valves, operated from two or more locations, systems through which the well is drilled. These valves are capable of either closing around the drill string to seal off the annular space or closing off the hole completely. A typical blowout preventer stack consists of three or more preventers of different types which are closed (either automatically or manually) when a potential blowout is indicated. Blowout preventer stacks are reliable if properly maintained and operated by well-trained drilling crews that react instantaneously when action is needed. While the blowouts that have occurred can be documented, the number of near accidents which have been successfully brought under control without serious consequences is not known. Documentation of successful blowout prevention would be helpful in evaluating the adequacy of equipment and personnel. It is unfortunate that only the spectacular failures receive public notice.

When a well is completed, the blowout preventer stack is removed and a series of pipe valves and guages called the "Christmas tree" is fitted on top of the well (oil flows through the Christmas tree to the pipeline or to offshore storage tanks). These valves can be shut either manually or remotely (if on the sea floor) to prevent or minimize pollution should a pipeline rupture or other leaks occur. Several other pieces of safety equipment are also added to minimize pollution risks.

Following a disturbing rate of failure when major accidents occurred, storm chokes (a type of subsurface safety valve designed to close if oil flow rate through it exceeds some specified value) have been subjected to more stringent U.S. Geological Survey regulations.

In transport from offshore to onshore facilities, oil sometimes leaks from pipelines (especially from older pipelines). Improved coating and cathodic protection of pipe can reduce pipeline corrosion rates. Many new pipelines also have automatic shutdown devices to stop the oil flow if a major leak occurs.

PROBABILITY OF OIL SPILLS AND BLOWOUTS

Despite tremendous technical advances, the only failsafe method of preventing man-made oil pollution of U.S. coastal waters is by not producing oil and gas from offshore and also by not importing any oil and natural gas. A recent study by the National Academy of Sciences has estimated that some six million metric tons of oil end up in the oceans annually. Of this total volume, 2.1 million metric tons or 35% was said to result from ship and tanker operations and 0.08 million metric tons or 1.3% from offshore oil production. Assuming that worldwide oil shipments are about five to six times as large as total offshore production, ship and tanker spills would still contribute more than four times as much oil to the ocean environment than worldwide offshore production.

To put the figure in the proper perspective, a five percent reduction in either waste oil discharge (river runoff) or loss through ship and tanker operations would likely do more to improve the quality of coastal waters than elimination of all offshore oil production. Not to belittle the importance of dealing with all other sources, but stronger efforts in amending these two problems in particular would have the most significance in protecting the oceans from oil pollution. This consideration is especially relevant if a decision not to develop an area having a favorable potential for oil and gas were to be based primarily on the need not to stress an already polluted environment beyond its ability to recover. Partial removal of one or more of the other sources of pollution in order to produce oil and gas offshore might be environmentally acceptable.

PROBABILITY

On the basis of U.S.G.S. data from the 1964–1974 period (U.S.G.S. reported 53 oil spill incidents involving 50 barrels or more) a blowout rate likely to cause a spill of 50 barrels or more is 0.04%. The blowout record in British offshore waters is equally impressive. Of more than 600 wells drilled, four blowouts have occurred (the most recent in 1971), releasing only natural gas.

Projecting future blowout probabilities in the U.S., one should take into account various significant technological improvements made since 1964. In the U.S. in particular, pollution prevention technology resulting from strict government regulations in response to environmental concerns are more advanced than in most other countries in the world.

ONSHORE ENVIRONMENTAL EFFECTS

Because of the importance of the coastal zone to the entire marine ecosystem, the environmental impact of OCS oil and gas operations is likely to be most critical in this area. While no conclusive studies have been made on long-term biological impact of oil pollution on marshlands, it seems that marshlands can be adversely impacted by repeated oilings, but a single oiling apparently does not prevent recovery of the area. The importance of wetlands should not be underestimated. They are the most productive part of the ocean environment, supporting much of the life in surrounding coastal waters through a food web based on vascular plant debris. Wetlands are also important geologically in stabilizing shorelines.

The primary adverse impact on wetlands would probably arise from channel dredging for pipelines, creation of dredge spoil banks and access roads for workers and equipment. Such activities would result in increased turbidity, resuspension of toxic substances, and alteration of salinity and circulation patterns in estuaries resulting in decreases in vegetation and habitat for organisms. In addition the water quality on which the spawning and breeding of many commercially valuable species may be adversely affected. However, these activities would impact only a small fraction of the coastal wetland area. Other environmental impacts onshore include land development disruption from construction and temporary facilities, increased air and water pollution, changes in plant and animal life, and noise pollution from construction and operations.

SOCIO-ECONOMIC AND LAND-USE IMPACTS

The coastal zone is an area rich in a variety of natural, commercial, recreational, industrial and aesthetic resources of immediate and potential value to the present and the future of the Nation. It is the area where most of the U.S. population lives, works and spends much of its leisure time. Whenever oil and gas resources are expected to be located offshore, the near-shore becomes the staging area for exploration of the Continental Shelf, and once oil is discovered, the coastal zone will need to accommodate some or all of the onshore developments related to offshore oil and gas production.

Problems related to onshore developments of the petroleum and petroleum-related industries are essentially problems associated with competing claims over the use of the coastal zone. Since many of the resources and natural amenities of the coastal zone are for legal and technical reasons treated as common property, they are subject to the same misuse and potential destruction as other common property resources such as air and water.

Onshore industrial development related to offshore oil and gas production is one of the many activities exercising increasing pressure on coastal lands. Second home developments, condominiums, hotels, boat marinas and other industrial and recreational facilities have mushroomed in the Nation's coastal areas in recent years. The various conflicting uses of the coastal zone need to be balanced and resolved in order to serve today's economic and social needs without depriving generations of the coastal zone benefits we cherish today.

Coastal zone impacts of offshore petroleum developments can be subdivided into economic, environmental, land use and social impacts. Each of these impacts is likely to differ significantly from region to region. Knowledge of socio-economic and environmental impacts associated with currently producing offshore oil and gas areas in the coastal zone, would provide some insight into the general problem areas and assist policymakers in parts of the country where no such developments have as yet taken place. Unfortunately, few (if any) detailed studies have been published on the socio-economic and land-use impact of offshore oil and gas developments on the coastal zone of Louisiana and Texas, where more than 90% of the Nation's offshore oil and natural gas is produced. Instead, a significant number of studies have hypothesized on the potential socio-economic and land-use impacts of offshore petroleum developments in the frontier areas of the Atlantic, Southern California and parts of Alaska.

Some of these studies were called for under the National Environmental Policy Act of 1969 whereas others were independent efforts by universities and consulting firms. The first major environmental impact study was undertaken by the Council on Environmental Quality (CEQ) and published in 1974. It projected socio-economic and environmental impact of offshore oil and gas developments in the Atlantic and Gulf of Alaska area. Several detailed environmental impact statements have been published since, and benefiting from the wealth of additional material now available, one may conclude that the CEQ report exaggerated land use requirements and employment creation (and consequently population movement) associated with Atlantic and Gulf of Alaska OCS developments. In fact, regional environmental impact statements issued since the publication of the CEQ report are almost unanimous in projecting considerably less acreage required to accommodate onshore developments and significantly less in employment creation projections associated with offshore development in the Atlantic and Gulf of Alaska.

On the basis of currently available resource data—estimated in the most recent U.S.G.S. projections, regional socio-economic and land-use impacts are likely to be very modest in comparison with total projected land use patterns, and employment and population—growth projections. The only exception may be the State of Alaska.

While Alaska has one of the best offshore oil and gas prospects in the Nation, it has a population of only about 325,000 . . . and a limited infrastructure. The development of the trans-Alaskan pipeline has proved to be a mixed blessing for the State. It has brought increased prosperity to a large number of Alaskans, but the high wages, coupled with the limited infrastructure, has caused considerable inflation and shortage of private and public services. Moreover, the crime rate in the State has increased rapidly. The Nation as a whole may benefit more from Alaska's energy developments than the State itself.

SIZE OF OCS IMPACTS

Actual socio-economic and land-use impacts of OCS developments on the coastal zone are dependent on a number of variables such as: the location, size, and rate of production of oil and gas fields; economic and policy decisions on the location of necessary onshore facilities to treat, store, transport and refine offshore petroleum; and, decisions on siting of optional developments associated with the oil and gas developments, such as refineries, petro-chemical and services industries.

In general, impacts of future OCS developments are likely to be greater in the so-called "frontier areas" (areas where no previous oil and gas leasing has taken place) than in the Gulf of Mexico (and possibly Southern California) where the infrastructure for the offshore industry already exists. This is primarily due to the fact that in frontier areas new pipelines and new onshore facilities have to be built. Additional labor will have to be imported from out of State, and new relationships must be developed between the oil industry and other existing industries in the area competing for resources. On the other hand, it's unlikely that with the exception of drilling rig and production platform yards, many other services industries will be established in the frontier areas. Existing facilities in Louisiana, Texas and other States, are likely to be able to handle the additional business generated by frontier area OCS developments.

In view of the already extensive oil-related industrial development in Louisiana and Texas, any additional discoveries of oil and gas off the coasts of those States are not likely to cause very significant regional impacts. Socio-economic and land-use impacts on areas with little or no previous oil and gas developments will vary from marginal to substantial. The heavily industrial States of the Mid-Atlantic are likely to be marginally impacted in case of a major oil or gas find beneath the Continental Shelves of the region. Additional industrial activity and population growth related to those developments is expected to be absorbed without undue constraints on existing resources. Impacts are likely to be somewhat more substantial in Southern California and in the New England States. The South Atlantic States and Alaska appear least equipped of all coastal regions with substantial petroleum potential, to handle the pressures of OCS developments.

COMPENSATION

Recent regional land use and employment projections related to OCS developments do not necessarily imply that within the Gulf of Mexico area, Southern California and other States with potential offshore oil and gas developments, local and especially rural and nonindustrial areas are not or will not be faced with difficulties adjusting to OCS induced growth. The increased population caused by OCS developments could place the greatest strain on the infrastructure of those local areas. New residents require new houses, hospitals, electric energy, fresh water, police protection, sewer systems, etc., which are difficult to provide, especially in smaller communities without a major infusion of front-end money. While States receive 37½ percent of the receipts from mineral leases from onshore Federal lands, under the OCS Lands Act, all revenues derived by extracting oil and gas from the OCS belong to the Federal Government.

The Federal Government received a total of 18.2 billion dollars for OCS leasing activities since the implementation of the OCS Lands Act of 1953. The share of offshore production from State lands has gradually declined as a percentage of total offshore production. For example, in Louisiana, 98 percent of offshore oil production was from

State-owned lands in 1954. Twenty years later, in 1974, the State's share had been reduced to 12 percent. Texas produced 100 percent of its offshore oil from State-owned lands in 1954 and only 26 percent in 1974. Producing and potentially producing coastal States alike are worried that with most of the future offshore oil and gas developments likely to take place on OCS lands where they have no jurisdiction, the initial cost of providing onshore services to the oil industries and their employees, will surpass revenues for some time to come. Many observers maintain that at least during the first years of OCS developments, total government costs will surpass State and local tax revenues from offshore oil and gas developments. Also, local officials fear that after the construction boom related to offshore petroleum developments, total employment (and population) in the region will drop, leaving States and local governments with large debts without the benefit of additional tax revenues. Hence, states want some compensation for the social and economic costs of OCS developments. While there appears to be little opposition to compensating coastal States for impacts resulting from OCS oil and gas development, there is broad disagreement on the amount to be provided to State and local governments, the manner in which it is distributed, and the purpose for which it may be used.

It has been suggested by some that a portion of Federal OCS revenues be earmarked for distribution to the States at a continuing predetermined rate. Opponents of permanent appropriations allege that such procedures result in uncertainty in determining the total funds voted for supporting governmental functions, and impairs the powers of Congress in directing and controlling spending.

Others have suggested compensating States based on "net adverse impacts" suffered, i.e., costs minus benefits from OCS activities. Opponents of the adverse impact approach cite the difficulty inherent in a distribution system which involves subjective judgment and must rely on many "unquantifiable" variables to determine the size of grants to a qualifying State. Moreover, they fear that the system will ultimately result in subjective determination by the administrator and/or complex regulations which will consume energy, money and time which could better be spent for other projects on the State's agenda. Supporters of the net adverse impact approach deny this and assert that methodologies can be developed on a timely basis for making "objective" determinations of the net impact and that the cost of administration will be no more burdensome than by a formula approach.

Finally, there are those who favor compensation for impacts which result from the siting of any "energy facilities" in the coastal zone whether OCS-related or not. Proponents of the comprehensive approach to coastal energy facility siting and impact compensation claim that energy facilities will inextricably be attracted to the coastal region, that national interest demands that the coastal zone absorb more than its proportionate share of the impact burden and therefore the coastal States are entitled to compensation for impacts resulting from activities that primarily benefit persons beyond the coastal region. Opponents allege that compensation for non-OCS-related energy activities will serve as an incentive for coastal States to site facilites in the coastal zone and therefore will be counterproductive to the goals of the Coastal Zone Management Act which was intended to protect the coastal environment. This conclusion is based upon the assumption that many energy facilities such as central power generating stations, oil refineries and processing facilities can be sited outside the coastal zone, and that given this option States will choose to place them in the coastal zone to take advantage of compensation reimbursements. Supporters dismiss this argument as a false issue and claim that such alternative siting options seldom exist and allege that energy siting decisions are based on economics and physical proximity to the necessary resources, and these attributes are found predominantly in the coastal zone.

FROM EXPLORATION TO PRODUCTION: ONSHORE IMPACTS AT VARIOUS STAGES OF OCS DEVELOPMENT

Following a lease sale, the first activity in the search for oil and gas is the conduct of geophysical surveys to locate structures favorable for oil and natural gas. This stage does not involve any onshore activity.

Once favorable structures have been identified, lessees will bring in drilling rigs or ships to determine if oil and/or gas are located in commercially interesting quantities. Drilling rigs and ships require harbor facilities and warehouse space. Employment per drilling rig averages about 140. Many of the specialized jobs are filled by people from out-of-State, many of whom are not likely to settle permanently in the new frontier area.

If prospects appear very favorable for oil and gas development, drilling rigs and later production platforms may be locally produced. The Atlantic area is likely to get one major platform yard of about 1,000 acres, probably in Virginia, but it is very unlikely that a construction yard will be built in Alaska. Once oil and/or gas have been found in commercially interesting quantities, production platforms will be put in place, additional production wells drilled, transportation systems to onshore facilities developed, and onshore facilities constructed. This is the most labor-intensive stage of the entire development. Both employment and land use requirements peak sometimes during this stage.

It should be pointed out that onshore facilities such as oil, water and gas separation plants, tankfarms, refineries, and LNG plants do not necessarily have to be built in the coastal area. In Scotland, for example, oil extracted from the first producing field, the Forties Field, is transported in buried pipelines to Cruden Bay and pumped from there by underground pipeline to the Firth of Forth (about 130 miles from Cruden Bay) where oil is treated, stored and refined. All that can be seen in Cruden Bay is a small pumping station located approximately three miles land inward. Careful planning of onshore facilities can prevent major damage to valuable coastal zone lands.

Oil can be shipped by pipeline to treatment facilities and refineries removed from the coastal zone areas, or, as in the case of Alaska and possibly other parts of the country which do not have refining capacities such as Massachusetts, from the coastal zone by tanker to treatment and refining facilities elsewhere. Natural gas is likely to be piped ashore where it will be treated (this can also be done on the production platform) and pumped to markets in existing pipelines. In Alaska, much of the natural gas will be liquified after treatment and shipped to markets in the lower 48 States.

AESTHETIC EFFECTS

In some areas such as Southern California, petroleum related structures be close to shore. Platforms can be seen from the coastline in Santa Barbara and will be seen in some parts of the recent Southern California lease sale area. The Gulf of Mexico is in certain placed dotted with production platforms, and many can be seen from the Louisiana coastline. Oil and gas developments in the Atlantic, especially in the Mid- and North Atlantic, will be far removed from the coastline, where platforms cannot be seen. Visual esthetics is a difficult quality to assess. The determination of whether something exhibits a pleasant aesthetic character is rather subjective and the very concept of esthetics may have different connotations to different people. In the case of an onshore platform, some individuals may view it with pleasure, but others may react in a negative manner to its overall esthetic qualities.

Visual impact of onshore facilities could range from high to low depending upon the sensitivity of siting, earthwork quantities, jetty construction, structure design, use of colors and subsequent landscaping. The net aesthetic impact will depend on the number, size and location of treatment, storage, and supply facilities, and on the need to build platform construction yards, refineries, petro-chemical complexes, LNG regasification terminals. Authorities in Great Britain have restricted construction of onshore facilities to certain areas planned for industrial use and have enforced strict construction and operation regulations. Careful planning could mitigate the negative aesthetic impact of onshore facilities in the United States as well.

SIZE OF DEVELOPMENTS

Almost two years ago, the Council on Environmental Quality published a five volume environmental assessment study of Atlantic and Gulf of Alaska OCS oil and gas developments. It showed the creation of very substantial employment opportunities in all areas but Alaska; significant population moves, in particular in the South Atlantic and to a minor extent in Alaska; very large land requirements to accommodate the necessary onshore facilities; and, very significant impacts on the infrastructure and on the public and private services sector.

In the meantime, a number of detailed regional environmental impact statements have been published for the North and Mid Atlantic, the Southern California coastal area, and Alaska. In almost all respects, the land use, employment and population growth figures of the CEQ report proved several orders of magnitude larger than the other studies.[1] Suffice to single out one area, the mid-Atlantic States. Because little knowledge exists on the actual resource base, the CEQ study assumed a low and high volume oil production of 250,000 and 750,000 barrels per day and a natural gas production of 0.30 and 0.90 billion cubic feet by 1985. On the basis of the high production figures, the CEQ report projected total empolyment in the mid-Atlantic to rise by just over 100,000 (35,000 for low development case). Locally, in Cape May and Cumberland Counties (NJ), employment would rise by 28,000 or 8,500 depending on the high or low development scenario. Total regional population would rise by 227,000 under the high development and 59,000 under the low development scheme.

According to 1975 draft environmental impact study by the Bureau Land Management on the proposed OCS lease sale no. 40 of 876,750 acres of mid-Atlantic OCS, production would range between 90 and 320,000 b/d of oil and between 0.85 and 3 billion cubic feet of natural gas. Total employment related to the development of OCS lease sale no. 40 would range from 4,200 (low development case) to 15,400 (high development case), and population movement from outside the region to the mid-Atlantic area would be between 5,600 and 20,800, a population increase of less than 1 percent from base case levels.

Finally, a study by Woodward-Clyde Consultants, estimating a peak production of 1.1. million b/d of oil and 8 billion cubic feet of natural gas, projects total employment in OCS-related activities in the mid-Atlantic States to peak at 28,000.

The differences between the employment figures, as one can observe from the figures, are not caused by different assumptions of the volume of oil and gas to be produced. The B.L.M. study—which assumes an oil and gas production figure of about 30 percent above the low development case of the C.E.Q. report—has arrived at an employment figure or less than one-half of the figure quoted in the CEQ report. The Woodward-Clyde study, which assumes a peak production of oil of about 30 percent above the CEQ "high development" case, has projected an employment figure of about 30 percent lower than figures quoted in the CEQ report.

Employment and population growth figures for other areas treated in the CEQ report are also greatly different from those of later regional studies conducted by other government agencies and private consulting firms. On the basis of the similarity of employment and population and growth trends in the more recent studies, one may conclude that impacts projected in the CEQ report were on the high side. Actual onshore employment and population growth associated with OCS activities could be substantial locally, but in most areas are likely to be marginal as a percentage of total regionally projected employment and population growth.

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[1] One of the reasons for the large differences in employment and land use projections in the CEQ report and regional B.L.M. and other impact studies is related to the fact that the CEQ report included refinery and petrochemical industrial developments as part of the overall OCS-induced growth pattern. The B.L.M. and other regional impact studies either showed that such development were not likely to occur as a result of OCS oil and gas production (demand for products rather than supply of raw materials was said to influence decision-making on construction of refineries and petrochemical industries), or they indicated that existing facilities could handle the additional oil.

Also, the CEQ report included all land use in its projection, whereas most of the other studies confined land use estimates to demand for industrial land. In some instances it was assumed that little—if any—population moves would take place, and hence demand for land would indeed be confined to industrial users.

Similar disparities can be observed in land-use patterns as projected in the CEQ report and the other studies. The CEQ report projected that between 16,100 and 49,300 acres would be needed onshore (depending on low or high resource development). The B.L.M. study, on the other hand, maintains that only a total of 160 to 645 acres will be needed. Again, the 645 acres in the B.L.M. study refer to a petroleum production of about 30 percent above the "low development" production in the CEQ report which would require 16,100 acres. Woodward-Clyde's oil and gas production estimates are about three times as high as the B.L.M. estimates and required acreage has been projected at 2,446 acres (including some 1500 acres for a platform production yard in Virginia). Again, figures on acreage required differ even if one takes into consideration differences in resources, estimates and production. However, the CEQ land use figures are once more several orders of magnitude higher than those of the other studies.

Comparing projected land use for onshore facilities in U.S. frontier areas with British experiences, B.L.M. estimates appear to be very sound. For example, the total acreage required for all onshore facilities related to the projected 1.2 million old Brent Field on the Shetland islands, has been calculated at 520. (120 for administration site, power station and processing; 60 acres for pumping metering and water treating; 40 acres for effluent water tanking; 120 acres for crude oil storage; 60 acres for LPG storage; and 120 acres for roads, track and storage.

To put the land use question in proper perspective, it is interesting to compare land use required for OCS development in Virginia as projected by Woodward-Clyde with others land—use requirements in that State. Woodward-Clyde projected that about two-thirds of the onshore developments associated with the pending mid-Atlantic OCS lease sale would take place in Virginia (about 1,500 acres). This is slightly less than the controversial "Chincoteague" second home development currently being planned in the coastal zone of Virginia. It will require 1,865 acres to build 4,500 houses.[2]

COASTAL ZONE MANAGEMENT

From 1940–1970, the U.S. population living in coastal areas has increased from 107 to 173 million. Population expansion is expected to continue in the years ahead, and by the end of the century, there may be almost as many people in the Nation's coastal zone as there are now people in the entire United States. Hence, competing demands on land use for home developments, recreation, fish and wildlife conservation industralization, etc., will continue. While total land use associated with OCS oil and gas developments are not likely to be anywhere as vast as projected by the CEQ, locally, demand for land to accommodate OCS related activities can be substantial.

Careful planning of activities in coastal areas has become imperative. Recognizing the urgency of the matter, Congress passed the Coastal Zone Management Act of 1972, designed to encourage coastal

[2] While a second-home development project cannot be compared with onshore facilities for oil and gas industrial development (especially from the aesthetic point of view), the comparison does provide an interesting inside in land use requirement for offshore oil development in the mid-Atlantic region.

States to develop tools for long-term planning and management of invaluable and irreplaceable resources. Congress has introduced legislation to revise the Coastal Zone Management Act of 1972.

EFFECTS ON FISHERIES

Although research findings are still inconclusive, preliminary results of studies on the effects of oil and gas developments indicate that no serious damage has been done to the fisheries resources of the Gulf of Mexico. In testimony before the National Ocean Policy Study, in 1974, Mr. Futtrell of the Sierra Club said that significant damage had been done to the oyster industry in the State of Louisiana. However, data compiled by the National Marine Fisheries Service has shown that the harvest of oysters in Louisiana remained relatively constant for the past 25 years. Annual variations of the oyster harvest cannot be contributed to any specific activity by man according to marine biologists of the National Marine Fisheries Service. Dr. Lyle St. Amant, Associate Director for Marine Fisheries and Coastal Management of the Louisiana Wildlife and Fisheries Commission stated that

> After 50 years of exposure to oil production, there is no evidence that the fishery production of Louisiana has declined or is significantly different from production in earlier years.

Oil industry spokesmen cite the OCS developments in the Gulf of Mexico region as a prime example of the peaceful and beneficial coexistence of oil and the fishing industry, especially sports fisheries. On the other hand, Gulf fishermen have frequently complained about offshore structures interfering with their pursuit of fish.

Studies have been made on the effects of the 1969 oil spill on the fisheries in Santa Barbara. Some observers have argued that fish landings in Santa Barbara decreased for several months after the blowout, but others maintain that while landings were indeed down in Santa Barbara, they increased in neighboring Ventura and Oxnard.

Several environmental impact statements for frontier regions have touched on the issue of the impact of OCS oil and gas developments on fisheries, but so far no conclusive evidence pro or con appears to exist.

TRADEOFFS

Nationwide, developments of offshore oil and gas will contribute to the goals of "Project Independence". Some say that offshore oil and gas developments are the key to achieving a significant degree of independence from foreign sources of oil, but others argue that the gap between total U.S. demand for oil and projected supply between now and 1985 is likely to continue to grow.

Oil demand has been estimated at between 20 and 22 million b/d by 1985. Of this, offshore production has been projected to contribute 2.3 to 3.0 million b/d. Today, offshore oil production is less than 1.5 million b/d.

While the Federal Energy Administration still maintains that total oil imports can be reduced to between 3 and 5 million b/d by 1985, most other recent studies put 1985 imports at between 10 and 12 million barrels a day. If FEA estimates prove to be correct, acceleration of OCS oil and gas development is likely to pay handsome dividends in the country's efforts to seek energy self-sufficiency. If, on the other hand, the more pessimistic projections prove to be correct, acceleration of OCS development will only make a small dent in the overall energy deficit (the difference between importing 10–12 or about 12–14 million b/d).

Proponents of accelerated development argue that even if the pessimistic projections prove to be correct, an additional 2 million b/d of domestic oil would save the nation more than $7.5 billion in foreign exchange (at current prices). They also maintain that higher domestic oil and gas output from the OCS will take some pressure of the demand for coal and nuclear power development in the United States.

Whatever the final outcome of the debate, with onshore oil and gas reserves expected to decline further, OCS oil and gas developments are likely to contribute more to total domestic oil supplies, but they will not by themselves solve the Nation's overall energy problems.

Chapter I. OCS Oil and Natural Gas Resources*

LOCATION OF OIL AND GAS RESERVES AND RESOURCES

The earth can be compared to a soft-boiled egg; the yolk being the liquid core, the white the mantle, and the shell the crust.* Geophysical studies have indicated that the mantle is made up of ultramafic, high density, igneous rocks which are relatively homogeneous. The thin crust lies above the mantle and includes not only igneous rocks, but also sedimentary rocks and their metamorphosed equivalents.

The part of the crust which underlies the oceans, and immediately overlies the mantle, possesses the properties of dense mafic igneous rocks such as diabase, gabbro, or serpentinized peridotite. This is known as typical oceanic crust because it forms a layer about five kilometers thick under the deep ocean basins. A layer of sediments and/or basalt is variably present as a thin veneer above the oceanic crust.

Under the continents, the crustal composition is quite different with a relatively thin mafic layer overlain or replaced by lower density sialic rocks (such as granite) which in turn may be overlain by many kilometers of sediments. This type of crust, known as continental crust, averages about 35 kilometers in thickness, and is thus many times thicker than the oceanic crust.

Floating in the heavy mantle, not unlike icebergs in the sea, the large areas of relatively light continental crust rise above the general level of the earth's surface and form the continents. Also like icebergs, their roots extend downward into the mantle material. The part of the continental masses emergent above the level of the sea constitutes about 30 percent of the earth's surface area. That part of the continents submerged below the level of the sea, but still fundamentally a part of the continents and standing above the general level of the ocean crust, makes up another 10 percent.[1] The remaining 60 percent of the earth's surface is composed of thin, dense oceanic crust.

The difference in elevation between the areas of continental crust and of oceanic crust is expressed by the continental slope, the most continuous and impressive of all the geomorphic features of the earth.[2] It is a submarine feature that surrounds almost all of the definitely continental areas of the globe, an escarpment three and one-half kilometers high and over 350,000 kilometers in length which is the surface expression of the transition from continental to ocean

*For a complete glossary of geological terms, see Appendix I

[1] Hedberg, Hollis D. "Continental Margins From Viewpoint of the Petroleum Geologist." American Association of Petroleum Geologists Bulletin, v. 54, n. 1, January 1970, p. 5.

[2] Ibid.

crust. The base of the continental slope approximately marks the contact between continent and ocean basin and between continental crust and oceanic crust, and thus constitutes the most obvious boundary of the continental margin.[3]

Landward from the continental slope is the continental shelf, a gently seaward-sloping submarine plain bordering the emergent continents and extending from the shore to the landward edge of the continental slope, where the increased slope gradient begins. Most of the continental shelf is the submerged extension of the emergent coastal plain and the balance of the shelf area is also underlain by continental crust. Continental shelves are, thus, integral parts of the continents. They range in width from a few kilometers to more than a thousand kilometers and constitute about 7.6 percent of the total ocean floor.[4] The outer limit of the shelf, the shelf edge, ranges in depth from only a few meters in some areas to over 600 meters in others, the average depth being about 130 meters. The average width of the shelf is 75 kilometers and its average seaward slope is a gradual 0 degrees 7 minutes. The thickness of sediments on the continental shelves is quite variable, but commonly may total several kilometers. It is probable that, in regard to petroleum source and reservoir characteristics, shelf sediments are similar to those on the coastal plain. Geological features important as petroleum traps such as folds, faulted structures, diapirs, unconformities, facies changes, etc., are as common on the outer continental shelves as they are near shore and on coastal plains. Most petroleum has been found in marine sediments, and the organic matter from which it has been derived has come, in general, from the marine life and terrestrial vegetation along the continental margins. Such organic matter, when deposited on the shelves, provides the source materials for the genesis of substantial amounts of petroleum in those areas where favorable geologic conditions and geologic history are present.

At the beginning of 1973, exploration for offshore petroleum was in progress on the continental shelves of 80 countries. About 780 oil and gas fields had been discovered offshore. These fields contain an estimated 172.8 billion barrels of oil (about 26 percent of the world total) and about 168.4 trillion cubic feet of natural gas.[5] Some 90 percent of the oil discovered offshore is contained in 60 giant fields each having reserves of 500 million or more barrels.

The search for petroleum on the submerged continental shelves of the world has accelerated at a rate surpassing earlier forecasts.[6] The shelves have become the major exploration focus of a large segment of the petroleum industry and, indeed, the offshore operations in progress may well be the beginning of one of the most massive oil-hunting eras in history. The first interest in the production of petroleum from submerged lands came with the discoveries of sizable onshore fields

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[3] Ibid.

[4] Ibid. p. 6

[5] Berryhill, Henry L., Jr. "The Worldwide Search for Petroleum Offshore—A Status Report for the Quarter Century 1947–72." Geological Survey Circular 694, U.S. Geological Survey, Reston, 1974, p. 1.

[6] Ibid.

immediately adjacent to the shoreline. The technology was developed to extend production seaward from the onshore fields. From such seaward extensions came indications that additional oil and gas deposits lay farther out in deeper water. Thus, the search has progressed into deeper and deeper waters as quickly as changes in exploration and production technologies have allowed.

In the United States, about 17 percent of the oil and natural gas produced comes from the continental shelf although only about three percent of the total shelf area has been developed.

Four segments of the U.S. continental shelf are generally regarded as either presently or potentially sources of oil and natural gas. These areas are: the Alaskan continental shelf consisting of the Gulf of Alaska, the Bering Sea, the Chukchi Sea, the Beaufort Sea, and Prudhoe Bay; the Gulf of Mexico shelf including areas off the coast of Texas, Louisiana, Mississippi, Alabama, and Florida (most of the oil development in U.S. waters have been in the Gulf); the Pacific shelf including the Santa Barbara Channel and the Southern California basins as well as offshore Oregon and Washington; and, the Atlantic shelf including the Georges Bank off New England, the Baltimore Canyon Trough (off New Jersey, Delaware, and Maryland), the Southeast Georgia Embayment from South Carolina to Florida, and the Blake Plateau off northern Florida and Georgia.

Atlantic Continental Shelf.—The Atlantic continental shelf represents a seaward extension of the onshore Atlantic coastal plain, a gently sloping cover of Mesozoic and Cenozoic (see Table 1 for geological time scale) sedimentary rocks extending over an area exceeding 260,000 square kilometers and stretching from New England to Florida. The continental margin offshore (encompassing about 446,000 square kilometers to the 200 meter depth curve) can be divided into a northern physiographic segment extending from New England to Cape Hatteras, North Carolina, and a southern segment between Cape Hatteras and the Florida Keys. The northern segment is characterized by a relatively smooth, gently dipping shelf extending seaward to a water depth of 100 to 200 meters. A break at this depth marks the beginning of the more steeply inclined continental slope. At the base of the slope the incline again decreases on the continental rise which gradually descends from a water depth of 2,000 to 3,000 meters to ocean basin depths which exceed 5,000 meters. The regional gradient of the continental slope varies from two to seven degrees, while the value for the shelf is generally less than 0 degrees 10 minutes, and for the rise less than one degree. The southern Segment of the margin differs from the northern in that the Blake Plateau intervenes between the continental shelf and slope and that the continental rise is essentially missing.[7] For the total Atlantic margin, an additional 343,000 square kilometers of continental crust exists between the 200 meter and 2,500 meter depths. Figure 1 shows that principal structural features of the Atlantic coastal plain and continental shelf.

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[7] "Draft Environmental Statement, Proposed Increase in Acreage to be offered for Oil and Gas Leasing on the Outer Continental Shelf." United States Department of the Interior, Bureau of Land Management, Volume 1, October 18, 1974, p. 173–176.

TABLE I.—GEOLOGIC TIME SCALE

Era, period, and epoch	Duration in millions of years (approximate)	Millions of years ago (approximate)
Cenozoic:		
Quaternary:		
Holocene (recent)	(1)	(1)
Pleistocene	2.5	2.5
Tertiary:		
Pliocene	4.5	7.0
Miocene	19.0	26.0
Oligocene	12.0	38.0
Eocene	16.0	54.0
Paleocene	11.0	65.0
Mesozoic:		
Cretaceous	71.0	136.0
Jurassic	54.0	190.0
Triassic	35.0	225.0
Paleozoic:		
Permian	55.0	280.0
Pennsylvanian	45.0	325.0
Mississippian	20.0	345.0
Devonian	50.0	395.0
Silurian	35.0	430.0
Ordovician	70.0	500.0
Cambrian	70.0	570.0
Precambrian	4,030.0	4,600.0

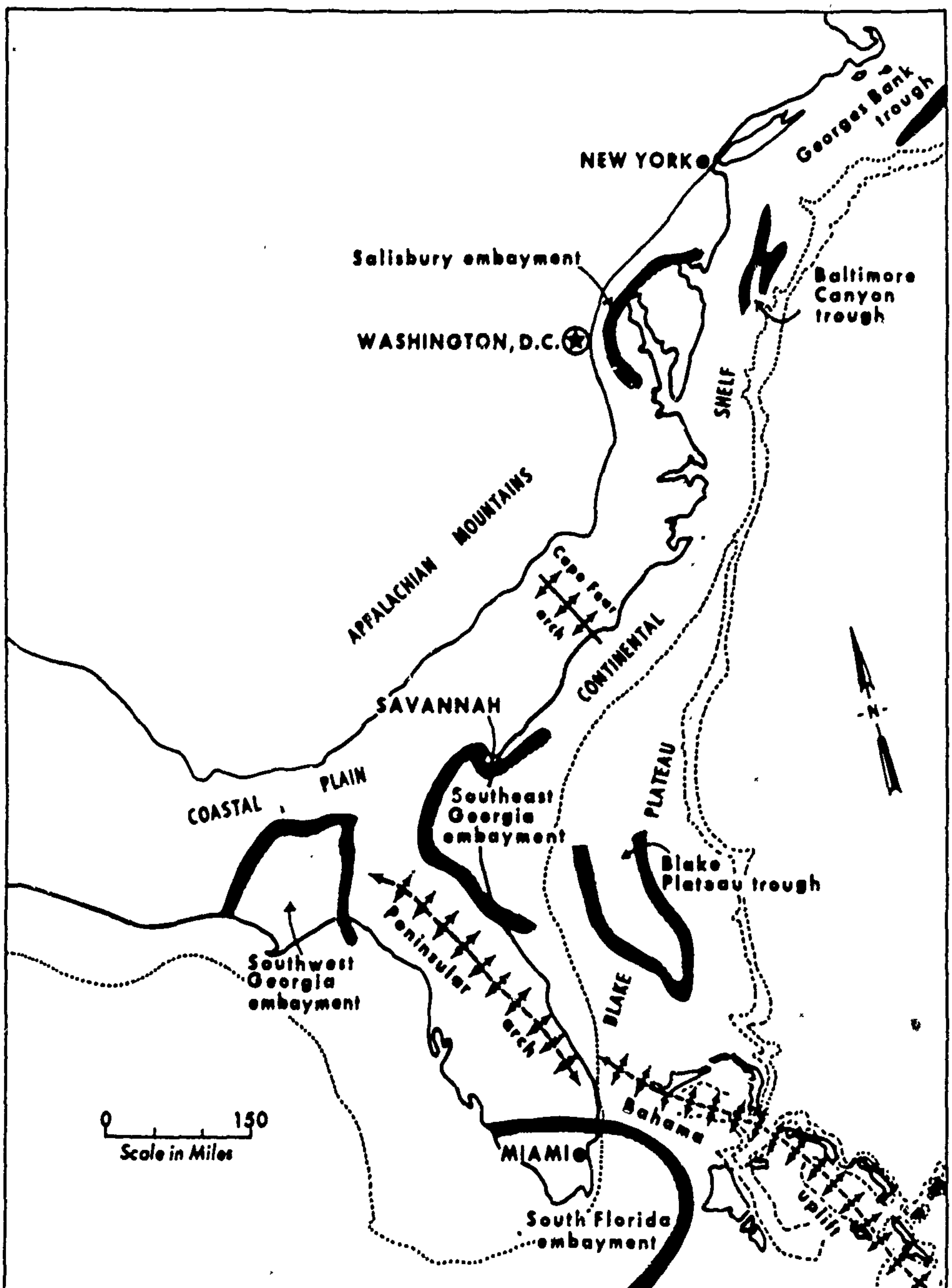
[1] Approximately last 5,000 years.
Note: Formation of the Earth's crust about 4,600,000,000 years ago.
Source: Adapted from McAlester, A. Lee. "The History of Life." Prentice-Hall, Inc., 1968, p. 152.
Note: The rocks of the Earth's crust are divided into four major eras of time as shown on the above scale. The 3 younger eras are further subdivided into periods and epochs. The Precambrian, the longest and oldest era, witnessed the beginning of life and the evolution of simple plants and animals. The Paleozoic Era was dominated by the invertebrate animals and fishes, the Mesozoic by reptiles (dinosaurs), and the Cenozoic by mammals with modern man first appearing in the Pleistocene epoch. Commercial oil and gas deposits can occur in rocks of Paleozoic, Mesozoic, or Cenozoic age. The best prospects vary in age from region to region depending upon the local geologic conditions of depositional environment and structure.

Included in the North Atlantic continental shelf is the East Coast shelf, Georges Bank, and the Gulf of Maine. The East Coast shelf is relatively featureless while the Gulf of Maine, to the north, has been altered by Pleistocene glacial events. Georges Bank, lying between the two, shares submarine topographic characteristics with each. Several large submarine canyons occur in the continental slope of the North Atlantic region.

The Gulf of Maine is an elliptical basin which is elongated toward the northeast and separated from the deep ocean basin by Georges Bank. It covers approximately 25,000 square miles (85,750 square kilometers) and has an average depth of 150 meters. The floor of the Gulf is composed of a complex series of rather deep basins (ranging from 100 to 300 meters in water depth) separated by low swells and flat topped banks which are covered by water which varies from 40 to 80 meters in depth. The sediment cover in the Gulf includes sand and gravel on the topographic highs and silt and clay in the basins. The character of the sediments, irregular topography, and general structure of the Gulf of Maine reflect the glacial history of the region. Seismic refection profiles suggest that the Gulf of Maine underwent two periods of uplift and erosion during which time most of the coastal plain sedimentary rocks were removed. As a consequence of these two erosional cycles, the sediment blanket overlying the basement complex is less than 50 meters thick.[8] A Pleisocene sedimentary section of less than 50 meters in thickness would not be expected to contain favorable oil and gas prospects.

[8] Ballard, R. D. and Uchupi Elazar. "Geology of the Gulf of Maine." The Association of Petroleum Geologists Bulletin, v. 58, n. 6, Part II, June 1974, p. 1158.

FIGURE 1



Atlantic Coastal Plain and Continental Shelf showing principal structural features.

Source: U.S. Department of the Interior/Geological Survey.

Georges Bank represents the most southwestern of a series of banks on the continental shelf that parallel the coast between Newfoundland and Nantucket Island. This northeast-southwest trending bank serves as a barrier between the Gulf of Maine and the open sea. Georges Bank is separated from the adjacent Scotian Shelf by the Northeast Channel and from the East Coast Shelf by the Great South Channel. The Georges Bank Basin is a structural depression in the continental shelf in the form of an arcuate trough approximately 300 kilometers long and 130 kilometers wide containing 7,930 meters or more of Mesozoic and Cenozoic sedimentary rock. The estimate is based on geophysical interpretations utilizing velocity information from Canadian offshore wells drilled on the western Scotian Shelf to the northeast of the Georges Bank Basin.[9]

The rocks in the basin are expected to have an overall stratigraphic similarity to the rocks in the western Scotian Shelf. The geophysical data indicate the existence of more than 4,270 meters of Lower Cretaceous and Jurassic carbonate rock, marine shale, evaporites, and sandstones and as much as 3,660 meters of Upper Cretaceous and Tertiary sandstone and shale. Structural deformation consists of high angle normal faulting in the basement rocks. The Lower Cretaceous and Jurassic sedimentary rocks in the Georges Bank basin may contain a significant amount of oil and/or gas. Because of its size, moderate water depths (less than 80 meters), and accessibility to high energy consumption areas of the United States, it is possible that the Georges Bank basin will play an important role in the U.S. energy future.[10] The sediment sections occurring in the central and south-central portions of the basin appear to have the better petroleum possibilities.[11]

The East Coast Shelf extends into the North Atlantic Shelf region, but it is a more characteristic feature of the mid-Atlantic region. The mid-Atlantic region is the portion of the East Coast continental margin that lies between 35 and 40 degrees north latitude. The width of this section of the continental shelf varies from 25 kilometers off Cape Hatteras to 140 kilometers off New Jersey. The seaward incline of the shelf ranges from about 0 degrees 04 minutes in the north to 0 degrees 07 minutes in the south, while the shelf break occurs at water depths of about 140 meters off central New Jersey but at only 55 meters off Cape Hatteras.[12]

The East Coast shelf contains a great variety of morphological features such as erosional channels and terraces and depositional ripples and sand waves. Embayed estuaries and barrier islands are the dominant coastal features of the region. The Delaware and Chesapeake Bays are the largest estuaries on the East Coast of the United States and represent drowned river channels which date from Pleistocene time. Barrier islands form a fairly continuous chain stretching from western Long Island to Cape Hatteras. Composed primarily of sand, the islands are generally long and narrow with elevations less than ten meters.

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[9] Schultz, L. K. and Grover, R. L. "Geology of Georges Basin," The American Association of Petroleum Geologists Bulletin, v. 58, n. 6, Part II, June 1974, p. 1159.

[10] Ibid. p. 1167.

[11] "Atlantic Shelf Oil and Gas Potential Still Uncertain." Department of the Interior, U.S. Geological Survey News Release, December 9, 1974.

[12] "Draft Environmental Impact Statement, Proposed Increase in Acreage to be Offered for Oil and Gas Leasing on the Outer Continental Shelf," op. cit., p. 195.

The structure of the mid-Atlantic margin represents a southward continuation of the trends evident beneath Georges Bank. The section thickens considerably off the coast of southern New Jersey, in the Baltimore Canyon trough. This basin appears to contain about 12 kilometers of undeformed post-Jurassic and Jurassic sedimentary rocks with a possibility of the existence of older sedimentary rocks below 12 kilometers in the deepest part of the Baltimore Canyon trough.[13] Geophysical surveys of various types which have been made in the area indicate, depending upon the interpretation given to them, the possible existence of several kinds of geologic structures, such as faults, basement intrusions, basement ridges, reefs, and perhaps even diapiric salt structures. Also, onshore well data indicate that there is a general tendency for the Lower Cretaceous sedimentary rocks to wedge out in the updip direction along a good part of the Coastal Plain. Near Cape Hatteras the entire Jurassic section has been shown to wedge out up the dip. There are indications that similar updip wedgeouts of lithologic units may occur throughout the Baltimore Canyon trough. These wedgeouts may form stratographic traps, which, although difficult to locate, could contain substantial petroleum reserves.[14]

The sediment thickness in the Baltimore Canyon trough (and in the Georges Bank basin) approach the sediment thicknesses in parts of the Gulf Coast and California coast regions, two proven offshore petroleum provinces. However, the Eastern Shelf sedimentary rocks are probably older and may have less porosity, and, therefore less reservoir potential, than the shelf sediments of the Gulf Coast and California. The structural environment favorable for petroleum accumulation appears to exist within the sedimentary prism beneath the Baltimore Canyon trough, but whether petroleum actually is present in economic amounts can only be determined by deep exploratory drilling.[15] In general, however, the sediments of the northeastern section are considered to be the best exploration prospects and, based on presently available data, the Baltimore Canyon trough is thought to have the best potential of the major East Coast offshore basins.[16] The stage has been set for a probable lease sale in the Baltimore Canyon area. The Interior Department has selected 154 tracts totalling 876,750 acres for a sale tentatively scheduled for May 1976.

The East Coast continental margin south of Cape Hatteras widens to 132 kilometers near the northern border of Florida and then narrows again to about three kilometers off West Palm Beach. South of Cape Lookout, the continental shelf is flanked by the Florida-Hatteras slope, a relatively smooth incline that drops off from a few meters in the north to more than 700 meters in the south, onto the Blake Plateau.

The Blake Plateau is a broad feature which ranges in depth from 60 to 750 meters along its western margin to 800 to 1000 meters along its seaward edge where it is flanked by a section of the continental slope known as the Blake Escarpment. The Blake Plateau surface is narrow and fairly steep in the north, but widens and flattens out

[13] Mattick, R. E., Foote, R. Q., Weaver, N. L., and Grim, M. S. "Structural Framework of the United States Atlantic Outer Continental Shelf North of Cape Hatteras." American Association of Petroleum Geologists Bulletin, v. 58, n. 6, Part II, June 1974, p. 1186.

[14] Ibid., p. 1187.

[15] Ibid. p. 1188.

[16] Offshore oil. Shell Reports, July 1975, p. 4.

toward the south. The southern portion of the plateau consists of a series of broad benches separated by slopes which range from 100 to 200 meters high. Numerous coral mounds also occur on the southern portion of the plateau, some up to as much as 100 meters high. The plateau is slowly subsiding with carbonates being deposited with the greatest accumulations being in the more rapidly subsiding western part. Most of the surface irregularities on the Blake Plateau have resulted from the erosive activity of the Gulf Stream.[17] The continental slope off Cape Hatteras is cut by numerous gullies which meet to form the Hatteras Canyon.

South of the Baltimore Canyon trough, the basement rock rises gradually to the southwest and descends again south of the Cape Fear Arch to form the Southeast Georgia Embayment. The embayment is comprised of about 3,000 meters of downwarped continental margin sediments, Jurassic through Holocene in age, deposited in a seaward thickening prism. It lies 32 to 113 kilometers offshore in water 18 to 180 meters deep, and extends from the Carolinas to northern Florida. Geophysical work indicates the presence of several sub-basins and faulting may also be present, but its patterns are currently unknown. There are indications of a basement ridge or fault block near the shelf-slope boundary.

The Blake Plateau Trough lies about 230 kilometers off the coast of Georgia and Florida. It covers an area about 240,000 square kilometers in extent and lies under waters which are between 450 and 1,800 meters in depth. The sedimentary rocks in the trough may be more than 6,000 meters in thickness, including an estimated 2,250 meters of Upper Jurassic and Lower Cretaceous sediments, which are the most promising prospects for oil and gas production.

In general, little is known about either the Southeast Georgia Embayment or the Blake Plateau trough concerning petroleum potential or structure. The areas have been compared to various existing oil provinces, but until they are tested by drilling their value is prospective only. Because of the rather deep water overlying the Blake Plateau trough, it may be some time before this area can be considered a serious candidate for development.[18]

Atlantic Continental Shelf Reserve Estimates.—The amount of oil and gas which may be discovered on the Atlantic Continental Shelf has been the subject of much speculation, but, whatever the projected potential, until the area is tested by drilling its value is prospective only. In February 1974, the U.S. Geological Survey estimated the undiscovered recoverable reserves of the offshore Atlantic (to a water depth of 200 meters) to be ten to 20 billion barrels of oil and natural gas liquids and 55 to 110 trillion cubic feet of natural gas. This is in contrast to an estimate by Mobil oil of only six billion barrels of oil and 31 trillion cubic feet of natural gas. In June 1975, the Geological Survey issued its latest estimate of the Nation's oil and gas reserves and adjusted the amount of undiscovered recoverable oil and gas reserves of the offshore Atlantic to 200 meters downward to two to four billion barrels of oil and five to 14 trillion cubic feet of natural

[17] "Draft Environmental Impact Statement, Proposed Increase in Acreage to be Offered for Oil and Gas Leasing on the Outer Continental Shelf," op. cit., p. 204.
[18] "Atlantic Shelf Oil and Gas Potential Still Uncertain," op. cit.

gas at the 75 and 25 percent probability levels. For the Atlantic offshore area, the Survey reported the estimates at the 75 and 25 percent probability levels as these levels were judged most applicable f planning purposes. It was noted that in frontier areas which lack indigenous or adjacent recoverable hydrocarbons, uncertainty is sufficiently great as to weaken probability at extreme ranges. At the 95 and 5 percent probability ranges (used in nonfrontier areas) the expectations in the offshore Atlantic are 0–6 billion barrels of oil and 0–22 trillion cubic feet of gas. Undiscovered recoverable natural gas liquids were given as 300 million barrels.[19]

The Survey has indicated that the probabilities for discovery of commercial accumulations of petroleum in the Atlantic coastal region appear to favor Upper Jurassic or Lower Cretaceous rocks in stratigraphically or structurally controlled traps beneath the continental shelf.[20]

Gulf of Mexico Shelf.—The Gulf of Mexico is a geologic basin with a depositional history dating from the Jurassic period, or possibly even earlier. Throughout Early and Middle Jurassic time, much of the Gulf region was covered by shallow seas in which restricted circulation permitted the extensive precipitation of evaporites such as salt and anhydrite. By Early Cretaceous time active organic reef complexes had formed and were extended over a large portion of the southern and eastern Gulf area. Reef growth continued through the Cretaceous and Tertiary periods accompanied in the southeast by slow regional subsidence. Thus, great thicknesses of shallow water carbonate deposits accumulated over the area of Florida, Yucatan, and the Bahamas.[21]

At the end of the Mesozoic, a period of widespread mountain building elevated the Rocky Mountains and subsequent erosion of this elevated terrain during the Tertiary period supplied vast quantities of clastic sediments such as sands, silts, and clays to the rivers draining into the north central and northwestern Gulf. These sediments accumulated in the slowly subsiding Gulf Coast depositional basin (geosyncline). Sedimentation continued throughout the Cenozoic Era and resulted in a southward progradation of the Gulf Coastal plain, while the basin regions receiving maximum deposition has migrated northeastward to the present location of the Mississippi delta. The Gulf of Mexico continental margin thus consists of an eastern geological province, comprised of shallow carbonate banks and relatively simple geological structure, and a western geological province of primarily land derived sediments and complex structure involving extensive faulting and salt mobilization.[22]

The present Gulf of Mexico is the largest Gulf in the world. It contains approximately 330,000 square kilometers of lands submerged under less than 200 meters of water. The continental margin of the

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[19] Miller, Betty M., et al., "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States." U.S. Geological Survey Circular 725, Reston, Virginia, 1975, p. 23–45.

[20] Maher, John C. "Geologic Framework and Petroleum Potential of the Atlantic Coastal Plain and Continental Shelf." Geological Survey Professional Paper 659, Washington, D.C., 1971, p. 65.

[21] "Draft Environmental Impact Statement, Proposed Increase in Acreage to be offered for Oil and Gas Leasing on the Outer Continental Shelf," op. cit., p. 267.

[22] Ibid. p. 268.

eastern Gulf represents a portion of a broad region of shallow water carbonate and evaporates that includes the Yucatan platform to the west and the Bahama platform to the east. The broad continental shelf off west Florida (the West Florida shelf) varies in width from less than 100 kilometers in the north to more than 250 kilometers in the southwest. (see Figure 2) The shelf is relatively flat, containing reefs and old submerged shoreline features as minor relief.

Source: Final Environmental Statement. Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf, Bureau of Land Management, 7 July 1975, p. 221.

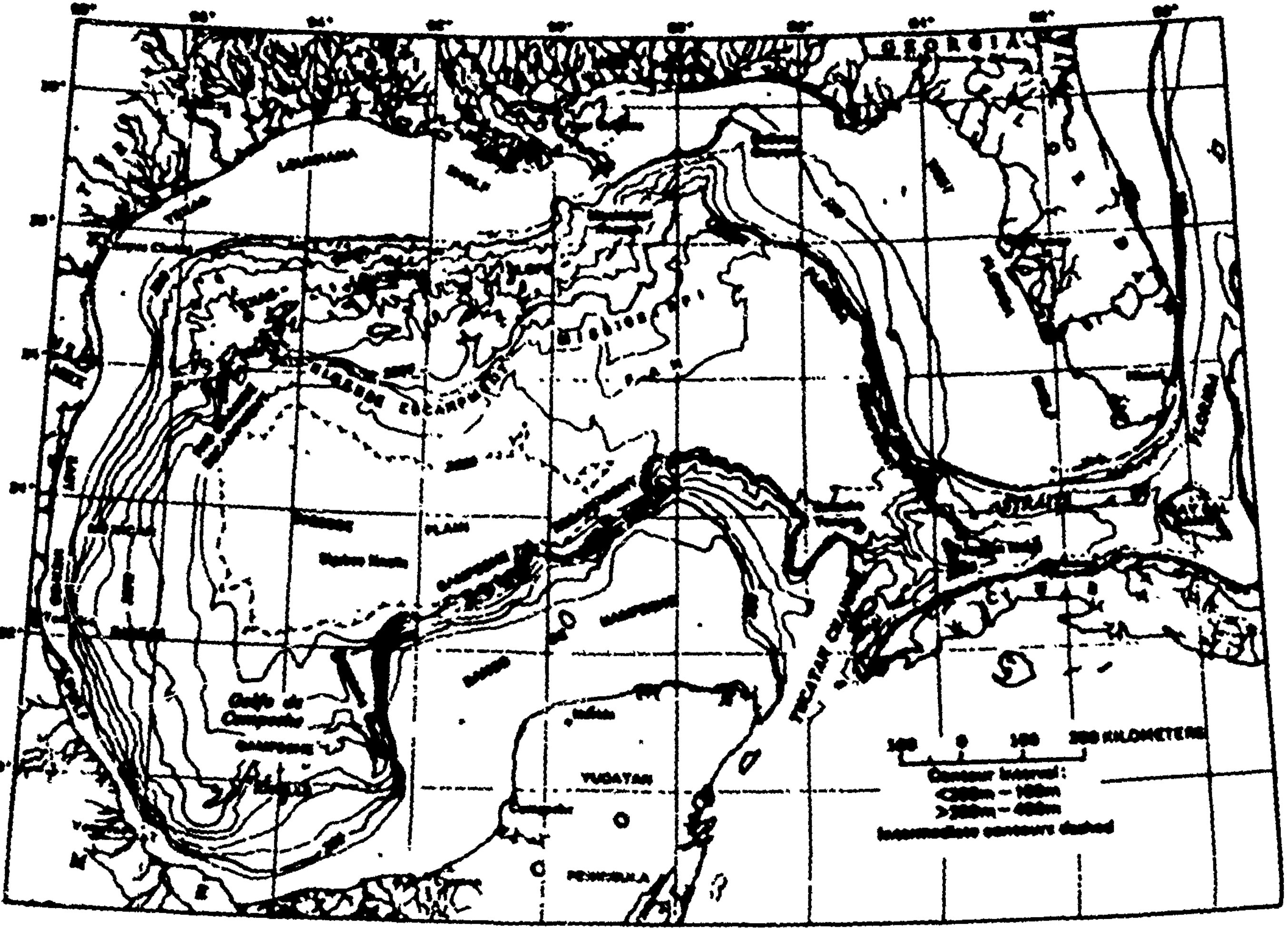

FIGURE 2.—Bathymetric map of the Gulf of Mexico showing major physiographic and structural features. Bathymetry adapted from Uchupi, (1967) and from Garrison and Martin, (1973.)

Source: Bureau of Land Management.

The West Florida escarpment lies at the base of the continental slope and forms the western boundary of Florida's continental margin. The escarpment is relatively smooth and steeply inclined north of latitude 27 degrees north, while the southern section has lesser gradients but more complex relief. To the south the eastern Gulf carbonate province is bordered by the Straits of Florida while in the north the boundary consists of a transition area joining it to the western Gulf clastic province. The DeSoto canyon, a submarine feature in the transition zone, is usually considered to be the physiographic boundary between the two provinces.[23]

There has been significant oil and gas production from the onshore Mississippi, Alabama, Florida area. The most productive zones in Mississippi and Alabama have been in Lower and Upper Cretaceous rocks. Production onshore in Florida is limited to two areas, one producing from Jurassic rocks and the other from Lower Cretaceous rocks. The promise of large fields offshore on the continental shelf of West Florida was based on projected structural, stratigraphic, and reef traps with Upper Jurassic and Lower Cretaceous rocks as the most likely oil and gas prospects. The first Federal least sale off Mississippi, Alabama, and Western Florida was held on December 20, 1973. The Department of the Interior accepted 87 bids totaling $1,491,065,230 for rights to drill on 485,396 acres. The $211,997,600 bid by Exxon, Mobil, and Champlin for Tract 83 in the Pensacola South area was the highest amount ever paid for a single tract in an offshore lease sale. The per-acre price of $36,805 was also a record. This tract, along with five others also purchased by Exxon, Mobil, and Champlin, is located on a portion of the Destin anticline, a large 32 by 80 kilometer structure with about 900 meters of closure that is comparable in size to some of the giant producing structures of the Middle East. The total price paid by the three companies for the six leases was $632,377,950. If the $632.4 million is added to the winning bids of nearby tracts, the total spent for the area around the Destin anticline was $784 million making the Destin anticline the world's most expensive single geological structure, perhaps even approaching $1 billion when all the drilling costs are added.[23a]

Exploratory drilling began in the area in mid-1974. By mid-1975 Exxon had spent an additional $15 million on seven dry holes on the structure.[24] Overall approximately 15 tests have been drilled, only one of which (Mobil South No. 1, drilled less than one mile from oil production in the Louisiana South Pass Area) was reported successful.[25] The first year of drilling in the Mississippi, Alabama, Western Florida sale area condemned, for oil and gas production, an estimated $850 million worth of acreage.[26] The string of exploration failures stretches across more than 460 kilometers of the northeastern Gulf. The sophisticated seismic amplitude analysis technique called "brightspot", which was used successfully in central Gulf Quaternary

[23] Ibid. p. 270.
[23a] Carmichael, Jim. Will Destin Dome be a Costly Dryhole? Offshore, October 1974, p. 48.
[24] "$15 Million Spent on Seven Offshore Florida Dusters; Exxon Group Moving to New Area." The Oil Daily, June 12, 1975.
[25] Cate, P. D. "Developments in Southeastern States in 1974." The American Association of Petroleum Geologists Bulletin, v. 59, n. 8, August 1975, p. 1429.
[26] McNabb, Dan. "Hopes Wane for Big New Reserves in Eastern Gulf." The Oil and Gas Journal, March 10, 1975, p. 21.

and Tertiary exploration, has failed thus far when applied to the Cretaceous and Jurassic prospects in this area. It is possible that a misapplication of the bright spot technique or a failure to recognize its limitations caused the high bonus prices which have not been justified by results.[27] There is, however, considerable untested acreage remaining to be drilled and another sale which is expected to include additional acreage off Mississippi, Alabama, and Western Florida, is tentatively scheduled for early 1976. The several noncommercial tests have reduced the priority of drilling current leases and have also probably reduced bidder interest in buying new tracts in the area. At present, some drilling is already being delayed particularly deep Jurassic tests which cost as much as three holes off Louisiana and entail a greater risk of being dry.[28]

Much of the lithological and structural character of the western Gulf of Mexico is related to the thick clastic sedimentary sequence which accumulated in the Gulf Coast geosyncline during the Cenozoic and to the extensive Jurassic evaporite that underlie this Cenozoic section.

The Gulf Coast geosyncline is a broad depositional trough that extends over much of the western Gulf continental margin. The continental shelf is the underwater extension of the generally smooth, gently dipping coastal plain. The offshore shelf of Texas and Louisiana ranges from 97 kilometers in width on the west to 257 kilometers in width off the Texas-Louisiana border. The continental slope of the northwestern Gulf marks the seaward limit of the geosyncline. The slope consists of two segments; a broad upper slope with shallow one to two degree inclines, and a steeper lower slope which breaks off abruptly along the Sigsbee and Rio Grande escarpments. The Gulf Coast basin contains Cenozoic sediments which exceed 15,250 meters in thickness. (See Figure 3) The rocks are predominantly clastics (sandstones, siltstones, and shales) which were originally derived from the uplands to the north and west and carried into the basin by the rivers draining into the Gulf of Mexico. Offshore Louisiana is a stable area of relatively simple tectonics.[29] Its most prominent structural anomalies are salt domes and a series of normal faults of regional extent. Less common are deep-seated, low relief uplifts and shale domes and ridges.

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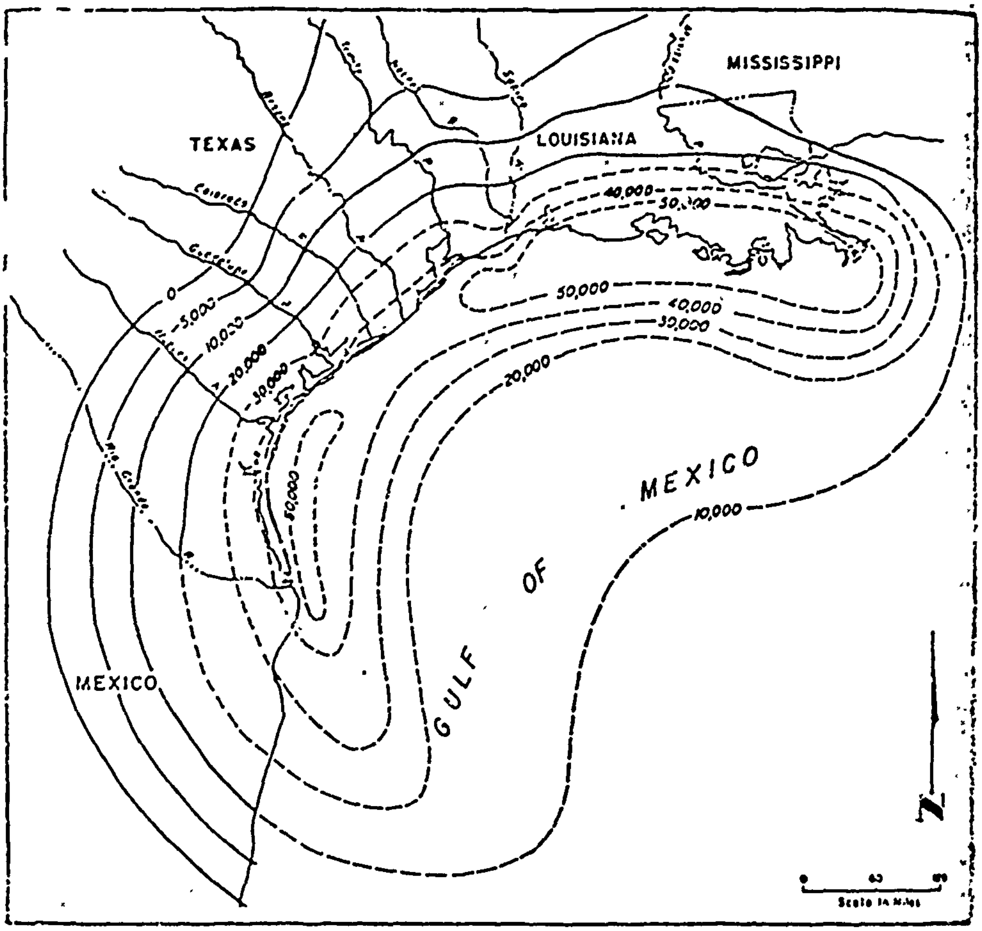
[27] Ibid., p. 22.
[28] Ibid.
[29] "Draft Environmental Impact Statement, Proposed Increase in Acreage to be Offered for Oil and Gas Leasing on the Outer Continental Shelf," op. cit., p. 279.

FIGURE 3.—Map showing generalized thickness of Cenozoic sediments in the Gulf Coast Geosyncline (From Hardin, 1962). Isopachs in feet.



Source: Bureau of Land Management.

Beneath the north central and northwestern Gulf, a thick layer of salt, deposited over 100 million years ago has slowly been deformed and mobilized by the weight of the overlying prograding Cenozoic sediments. In some areas of sufficient overburden, the lower density salt has risen buoyantly upward, upwarping and often penetrating the overlying strata. Salt domes are formed in this manner with the enclosing sedimentary rocks commonly turned up and complexly faulted next to the salt plug. Such enclosing rocks may serve as reservoirs for oil and gas.

Sedimentation in the Gulf of Mexico has been complicated by the transgression and regression of the shoreline in response to changes in sea level, however the overall pattern of deposition is one of regression interrupted by minor transgressions. Decay of buried vegetation from brackish water marshes is thought to be the primary source of hydrocarbons found in continental shelf deposits.[30]

The environment of sediment deposition is significant in relation to oil and gas production. The sediments of the outer shelf and upper

[30] Ibid., p. 289.

slope appear to have the greatest oil and gas potential as this is the area of optimum sandstone to shale ratio, the shale being the source rock and the sandstone providing the reservoirs into which the hydrocarbons migrate. Also, in this environment the organic material deposited with the clays is preserved and not oxidized while the increased overburden initiates salt flow which triggers the growth of salt domes, thus providing potential traps for the hydrocarbons.[31] Environments seaward of the outer shelf-upper slope have progressively less sand to act as reservoirs and areas to the landward have progressively less organic matter to act as source material for the hydrocarbons.

Since natural production of oil and gas frequently occurs along the continental shelf-slope break, the progradation of the north central Gulf depositional regime has resulted in the seaward migration of this production zone and the development of a series of progressively younger bands or trends. Figure *4* exhibits the Late Tertiary and Quaternary production trends underlying the western Gulf outer continental shelf.

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[31] Ibid., p. 292.

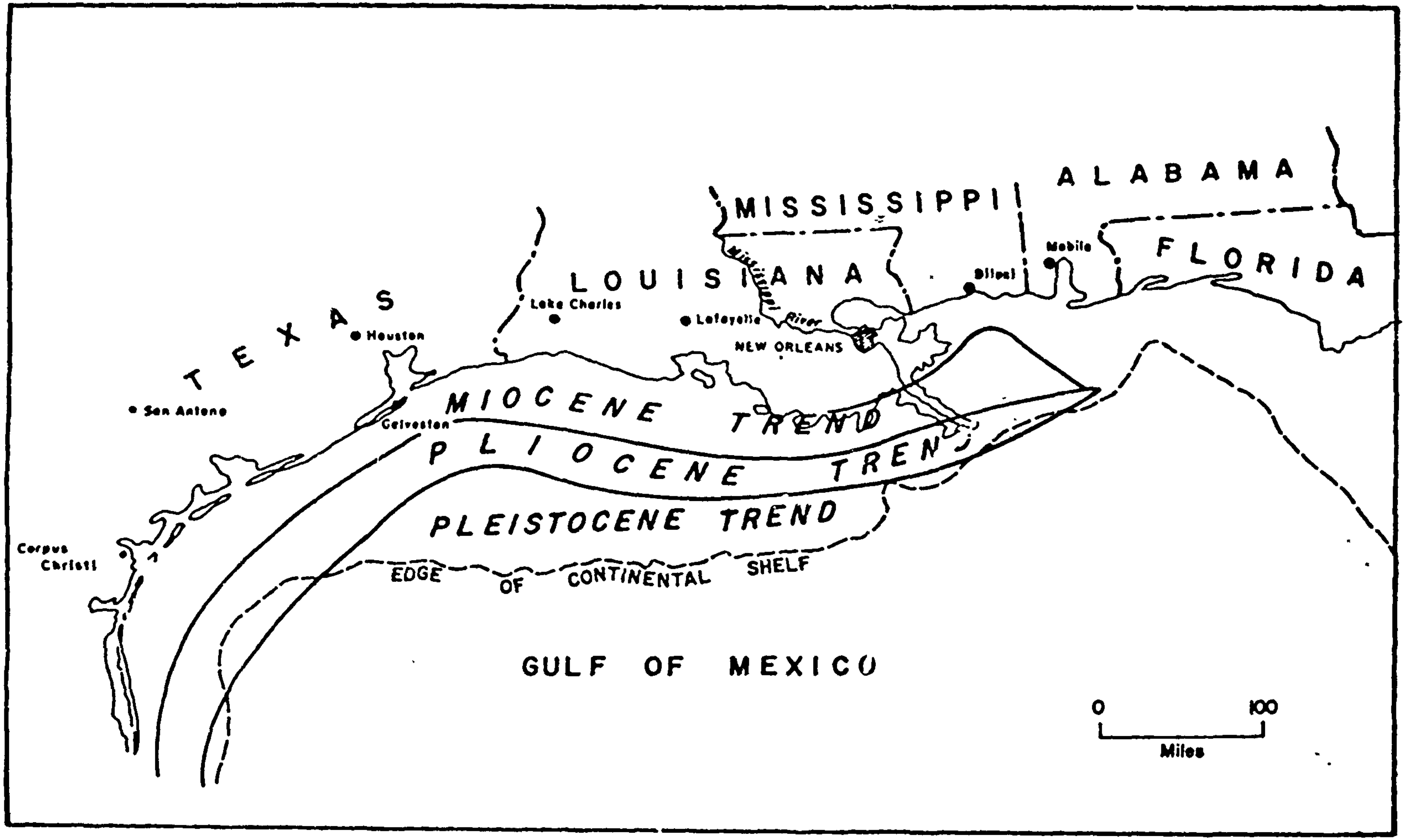
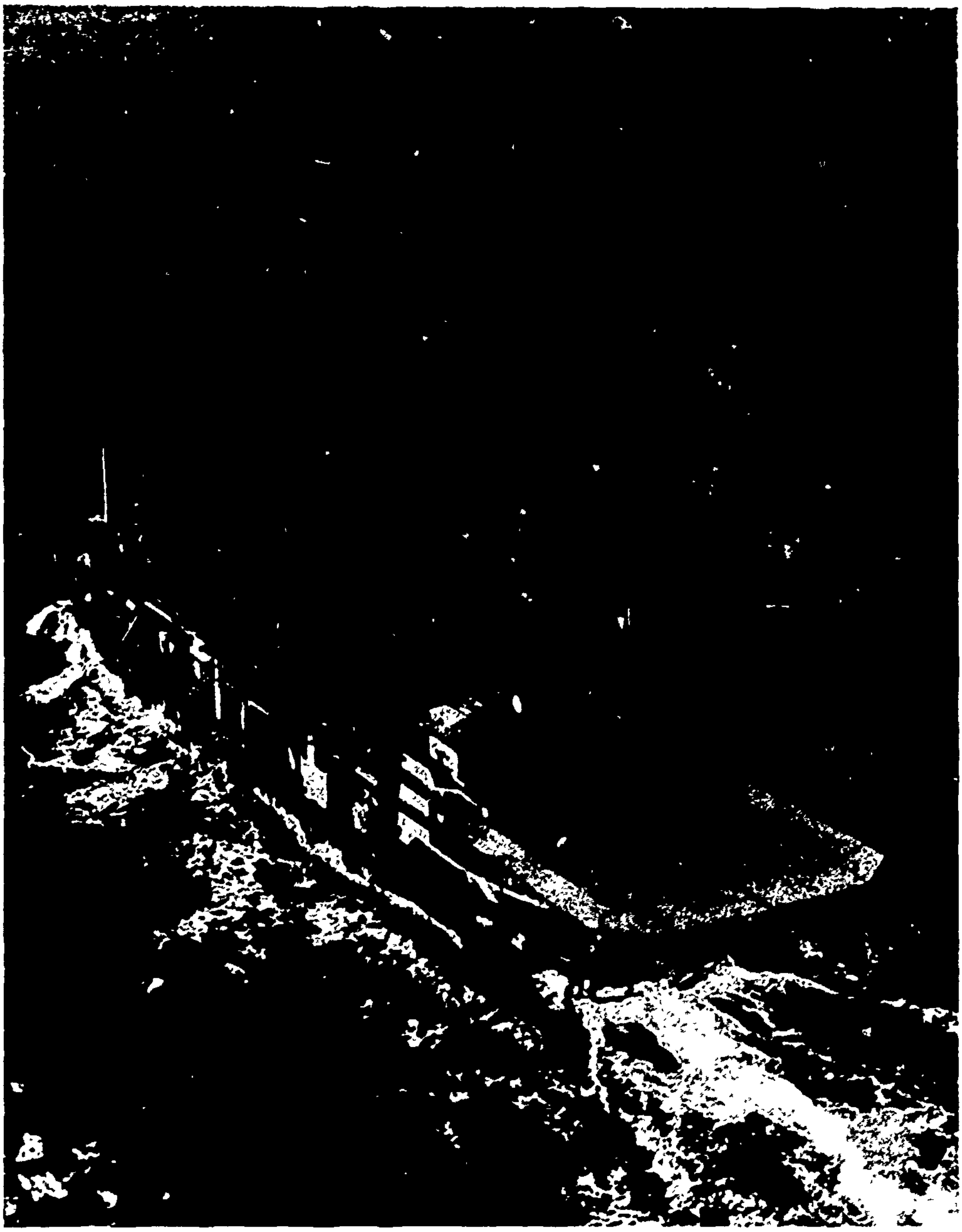


FIGURE 4.—Productive trends offshore Louisiana and Texas
Source: Final Environmental Statement, Bureau of Land Management, p. 233.



The self-propelled drilling ship Glomar Isle Courtesy Exxon Corporation

The Louisiana Gulf Coast includes 21 continental shelf areas which extend from the shoreline to a water depth of 1,983 meters. In this region, rocks ranging in age from Miocene to Pleistocene contain large reserves of oil and gas. The hydrocarbons are present primarily in sandstone structural traps where the southward regional dip is interrupted by salt structures, both piercement and deep-seated, or by normal faults of regional or local extent. Structural-stratigraphic traps are fairly common also and are becoming more important in exploratory programs because most of the more obvious structural traps have been drilled.[32]

[32] Callahan, Robert L. and Lueck, Everett W. "Developments in Louisiana Gulf Coast in 1974." The American Association of Petroleum Geologists Bulletin, v. 59, n. 8, August 1975, p. 1419.

There are approximately 378 fields on the Federal continental shelf of the Gulf of Mexico. Of these 232 primarily produce gas and 94 primarily produce oil.[33] Production depths range from about 305 meters to about 6,1000 meters with most production occurring between 2,440 meters and 3,660 meters. The most prolific offshore production is from the Miocene of the eastern Louisiana shelf. The next most productive trend is in the Pliocene of the central Louisiana shelf which produces about half oil and half gas. The Miocene of the western Louisiana shelf is the third most productive trend, producing mostly gas, and the Pleistocene of western Louisiana ranks fourth.[34]

U.S. Geological Survey records show that 4.497 billion barrels of oil and condensate have been produced from the Louisiana section of the Gulf Coast continental shelf through 1974. Twenty-three percent of this oil was produced from state of Louisiana offshore lands while 77 percent came from the Federal outer continental shelf.[35] Oil and Gas condensate production from the Federal shelf area off Louisiana through 1974 amounted to 3.463 billion barrels. Oil and condensate production off Texas through 1974 totaled 29.272 million barrels, 37 percent of which was produced from state offshore lands and the remaining 63 percent from Federal OCS lands off the state of Texas.[36] Gas production off Texas through 1974 was 2.149 trillion cubic feet, 49 percent of which came from state offshore lands and 51 percent of which from the Federal OCS. For Louisiana, gas production through 1974 amounted to 29.415 trillion cubic feet.[37] Twenty-two percent of this gas was produced from offshore state lands and 78 percent from Federal OCS lands off Louisiana. By the end of 1974 some 12,389 wells had been drilled offshore in the Gulf of Mexico. Of these 6,027 have been completed for production and 4,999 have been plugged and abandoned.[38] For additional statistics regarding oil and gas operations offshore in the Gulf Coast region see Appendix 2 through 11.

To date the oil industry has spent over $12 billion for the right to explore for oil and gas in the Gulf of Mexico, but this represents only a fraction of the total investment that has been made.[39] More than 5,000 miles of pipelines have been constructed and a total of 804 production platforms installed, of which 647 are still on active leases.[40] Of the total 804 platforms constructed in Gulf waters, 134 have been salvaged, hurricanes have claimed 17, and six have been lost to fires, blowouts, and other unusual causes.[41]

The Gulf of Mexico has been virtually stripped of its prime unleased oil and gas prospects by lease sales during the past five years and is shifting into a high pace of drilling, development, and production. The almost $12 billion spent on Federal leases alone netted the oil industry some 4.88 million acres; more than $7 billion went for 2.9 million acres off Louisiana. Now with only lean prospects remaining, leasing in the

[33] "Draft Environmental Impact Statement, Proposed Increase in Acreage to be Offered for Oil and Gas Leasing on the Outer Continental Shelf," op. cit., p. 293.
[34] Ibid. p. 295.
[35] Harris, Walter M., Piper, Sharon K., McFarlane, Bruce E. "Outer Continental Shelf Statistics." U.S. Geological Survey, June 1975, p. 87.
[36] Ibid.
[37] Ibid.
[38] Ibid. p. 35.
[39] Carmichael, John, "Industry Has Built Over 800 Platforms in the Gulf of Mexico." Offshore, May 1975, p. 230.
[40] Ibid.
[41] Ibid. p. 231.

Gulf is down. The heavy leasing in the first half of the decade, however, will allow for increased drilling and development activity in the Gulf during the second half of the 1970's.[42] Of the 1,068 Gulf tracts leased since 1970, 48 are producing, 105 are nearing production status, and 901 are still under primary term. None of this year's purchases have as yet been drilled.[43] As operators attempt to compensate for overall declining Gulf production, the new offshore tracts must assume a greater share of the load.

Gulf of Mexico Shelf Reserve Estimates.—The demonstrated offshore oil and gas reserves of the Gulf of Mexico to 200 meters are 2.262 billion barrels of oil and 35.348 trillion cubic feet of gas.[44] On February 14, 1974, the U.S. Geological Survey estimated the undiscovered recoverable oil and gas liquids resources of the Gulf of Mexico to a water depth of 200 meters to be from 20 to 40 billion barrels and the undiscovered recoverable natural gas reserves to be from 160 to 320 trillion cubic feet. Mobil Oil, in contrast, had estimated undiscovered oil and gas liquid resources to be 14 billion barrels and undiscovered gas resources to be 69 trillion cubic feet in the Gulf.[45] In June, 1975, the U.S. Geological Survey revised their estimates sharply downward. The undiscovered recoverable resources in the Gulf to 200 meters were reduced to three to eight billion barrels of oil and 18 to 91 trillion cubic feet of gas. The low value of the range is the amount associated with a 95 percent discovery probability and the high amount is the quantity associated with a five percent probability. The undiscovered recoverable natural gas liquids were given as 1.3 billion barrels.[46]

The lower figures for undiscovered recoverable hydrocarbons illustrate absence of prime unleased oil and gas prospects in the Gulf and also that the area is moving from the exploration to the development stage.

Pacific Continental Shelf.—The Southern California borderland is a complex of basins, islands, banks, ridges and submarine canyons; the edge of the continental shelf, the Patton Escarpment, is located over 150 kilometers from shore with water depth exceeding 4000 meters. Also on the borderland are seven major islands and nine basins. The borderland lies within two of California's geomorphic provinces, the Peninsular-Range Province and the Transverse Range Province.

The Peninsular Range of California extends from south of the Santa Monica Mountains, the northern limit of the Los Angeles Basin, to south of the Mexican border. The ranges are separated by valleys which trend northwest-southeast and represent, for the most part, active branches of the San Andreas Fault system. The southern Channel Islands, San Nicholas, San Clemente, Santa Catalina, and Santa Barbara, are included in the Peninsular Range province.[47]

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[42] McNabb, Dan. "Leasing Ebbs, But Drilling To Hold High in U.S. Gulf." The Oil and Gas Journal, June 23, 1975, p. 60.

[43] Ibid.

[44] Miller, Betty M., et. al., "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States." op. cit., p. 28–31.

[45] West, Jim, "U.S. Oil-Policy Riddle: How Much Left to Find?" The Oil and Gas Journal, September 16, 1974, p. 27.

[46] Miller, Betty M., et. al., "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States." op. cit., p. 28–31, 45.

[47] Final Environmental Impact Statement, Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California." U.S. Department of the Interior, Bureau of Land Management, v. 1, August 1975. p. 68.

The Transverse Range province is oriented in an east-west direction and is composed of a series of mountain ranges and valleys generally made up of late Mesozoic and Cenozoic age sedimentary rocks. The components of the Transverse Range include both the lowlands of the San Bernardino and Los Angeles plains and the San Bernardino and San Gabriel Mountains, two of the most rugged and highest ranges in Southern California. Westward from Los Angeles stretch the Santa Monica Mountains. The four northern Channel Islands (San Miguel, Santa Rosa, Santa Cruz, and Anacapa) are projections of this range. North of the islands, but still included in the Transverse Range Province is the Santa Barbara Channel.

The topographic high point of the Channel Islands is 661 meters on the Island of Santa Cruz. The dominant bathymetric features include numerous closed submarine basins separated by submarine ridges. The depths in the offshore vary greatly from submarine ridges cresting within four meters of the surface to the larger basins having depths exceeding 2000 meters.

The larger basins have water depths as follows:

	Meters
Catalina basin	1,350
East Cortez basin	1,950
San Clemente basin	2,107
San Nicholas basin	1,826
San Pedro basin	900
Santa Barbara basin	625
Santa Cruz basin	1,966
Santa Monica basin	948
Tanner basin	1,549

Source: Bureau of Land Management.

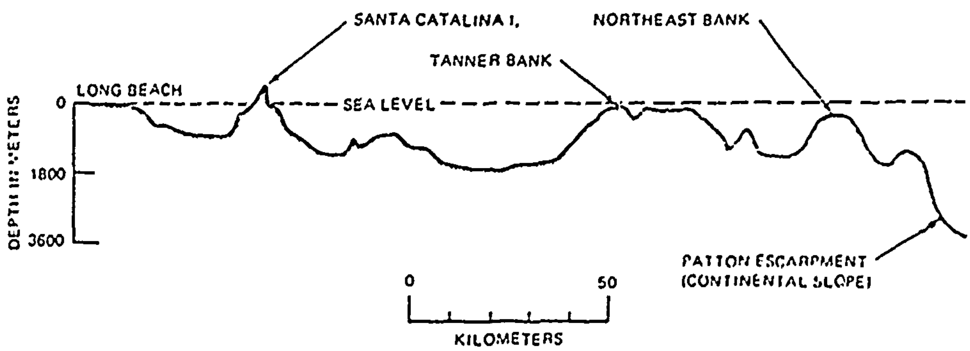
Profiles and cross sections of the basins are shown in Figure 5.

Many of the offshore basins are filled with great thicknesses of Late Cenozoic marine sediments and are probably similar to the Los Angeles and Ventura onshore basins. The nearshore basins are usually shallower and broader and contain the majority of the terrestrial sediments.

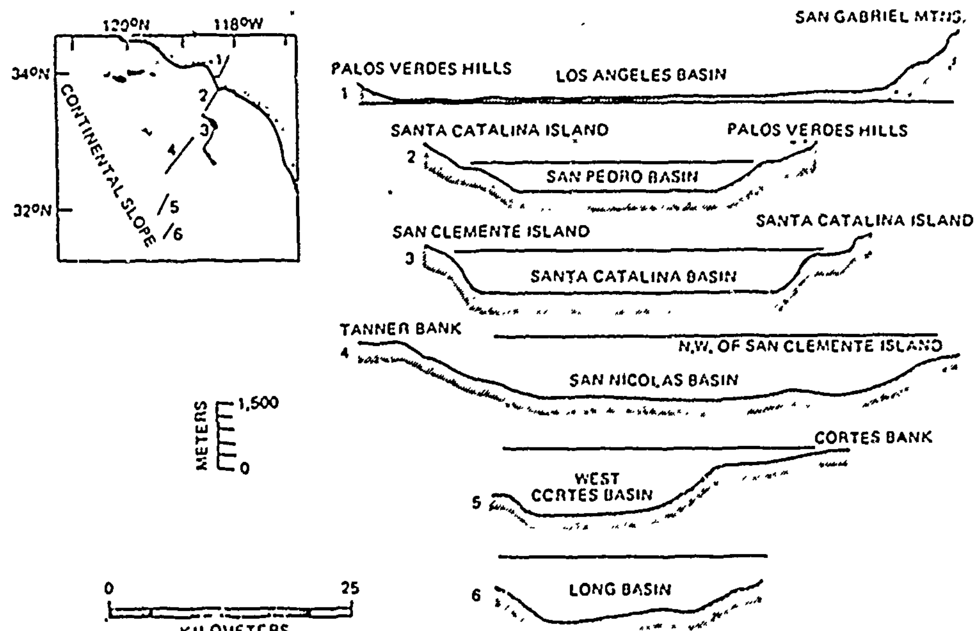
On the mainland and on the islands, basement rocks consist of several distinct types, all believed to be older than Late Cretaceous in age. Unconformably overlying the basement rocks are thick sequences of Upper Cretaceous rocks. Lower Tertiary marine strata, primarily Eocene, occur in the coastal mountains. They consist of deep water sediments as much as 6,100 meters thick. Oligocene age strata are primarily nonmarine. Throughout the area sedimentary and igneous rocks of Miocene age are widely distributed and surpass the early Tertiary rocks in extent and thickness at many places. Marine strata of Pliocene age are, in general, restricted to existing deep depositional basins and their closely adjacent margins. Thick accumulations of marine and nonmarine deposits of Pleistocene and Holocene age occur along the mainland coast and in the exterior basins.[48]

[48] Ibid. p. 71.

Figure 5



A Typical Profile of the Sea Floor Off Southern California. From Shepard 1963, fig. 130.



Cross Sections Showing the Inverse Relationship of Shoaling, Broadening, and Flattening of Basins with Distance from the Mainland Shore. From Emery 1960, Fig. 50.

Source: Bureau of Land Management.

An understanding of offshore petroleum potential relies heavily on present knowledge of presumably analogous onshore regions such as the Ventura, Santa Barbara, and Los Angeles Basins. Various studies of the rocks suggest that a number of the shalelike or silty units, ranging in age from Late Cretaceous to Late Miocene, contain sufficient carbonaceous or other organic matter to constitute potential source rocks for petroleum. Whether or not the deformational and thermal history of any of these units has been appropriate for the genesis and migration of oil and/or gas is not known.[49] However, by analogy with onshore areas in the Ventura and Los Angeles Basins and offshore in the Santa Barbara channel it would appear that conditions may have been favorable.[50]

Offshore production plays an important role in California's petroleum output picture, accounting for more than one out of every four barrels produced. Before the end of the year the Interior Department plans to hold another OCS sale offering some 1.6 million acres off southern California. (See Appendix *12.*) Additional sales are tentatively planned for 1977 and 1978. The proposed sales would be a continuation of Federal OCS leasing off California which began in 1963 and continued with sales in 1966 and 1968 in the Santa Barbara channel area.

Currently there are two producing fields in the Federal OCS area, Don Cuadras Offshore and Carpinteria Offshore, both located in the Santa Barbara Channel. There are five producing platforms in the Federal areas with 186 production wells in operation as of November 1974.[51] Output from these wells in 1974 was 16.78 million barrels of oil and 5.57 billion cubic feet of gas. This is down from the 1973 figures of 18.92 million barrels of oil and 7.29 billion cubic feet of gas. Cumulative production to 1974 was 126.35 million barrels of oil and 56.44 billion cubic feet of gas.[52] There have been 79 exploratory wells drilled in the Federal shelf portion of the Santa Barbara channel and 61.5 miles of pipeline has been constructed from Federal leases in the Channel to the shore.

State offshore oil and gas activity extends from the Santa Barbara Channel south to Orange County within the three mile limit. There are 131 leases covering 165,157 acres on state land and about 20 leases covering some 20,000 acres on municipal lands. These leases are developed by nine platforms, seven islands, three piers, and 19 shoreside sites from which 1,606 wells produced 70.58 million barrels of oil and 30.6 billion cubic feet of gas in 1973. Production of oil amounts to about 193,000 barrels per day.[53]

The Santa Barbara Channel has the best known petroleum potential of the Pacific OCS areas with over 30 producing oil and gas fields. All current production occurs from rocks ranging in age from Cretaceous through the Tertiary. The future petroleum potential of the Channel is also considered to be favorable as the offshore continuation

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[49] Ibid.
[50] Ibid.
[51] Ibid., p. 25.
[52] Harris, Piper, and McFarlane, op. cit., p. 62.
[53] Final Environmental Impact Statement, Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California, op. cit., p. 25–26.

of onshore stratigraphic potential structural traps have been identified along with thick sandstone sections that offer oil and gas reservoir possibilities.

The onshore limit of the central and northern California margin is defined by the western front of the California Coast ranges which are bounded on the south by the Transverse ranges and on the north by the Klamath Mountains. Offshore, the seaward edge of the continental margin is defined as the 3,000 meter contour line which lies at the foot of the steeper continental slope where it joins the lower declivity of the continental rise. To the north and south offshore, the extensive Mendocine and Murray fracture zones are the limits. The significant features of the northern and central California sea floor are a very narrow shelf with a slope averaging three degrees, a very steep canyon cut slope, a broad continental rise containing deep sea fans, and a broad bank formed on the upper slope west of the Transverse Range.[54] (See Figure 6.)

[54] "Draft Environmental Impact Statement, Proposed Increase in Acreage to be Offered for Oil and Gas Leasing on the Outer Continental Shelf." op. cit., p. 383.

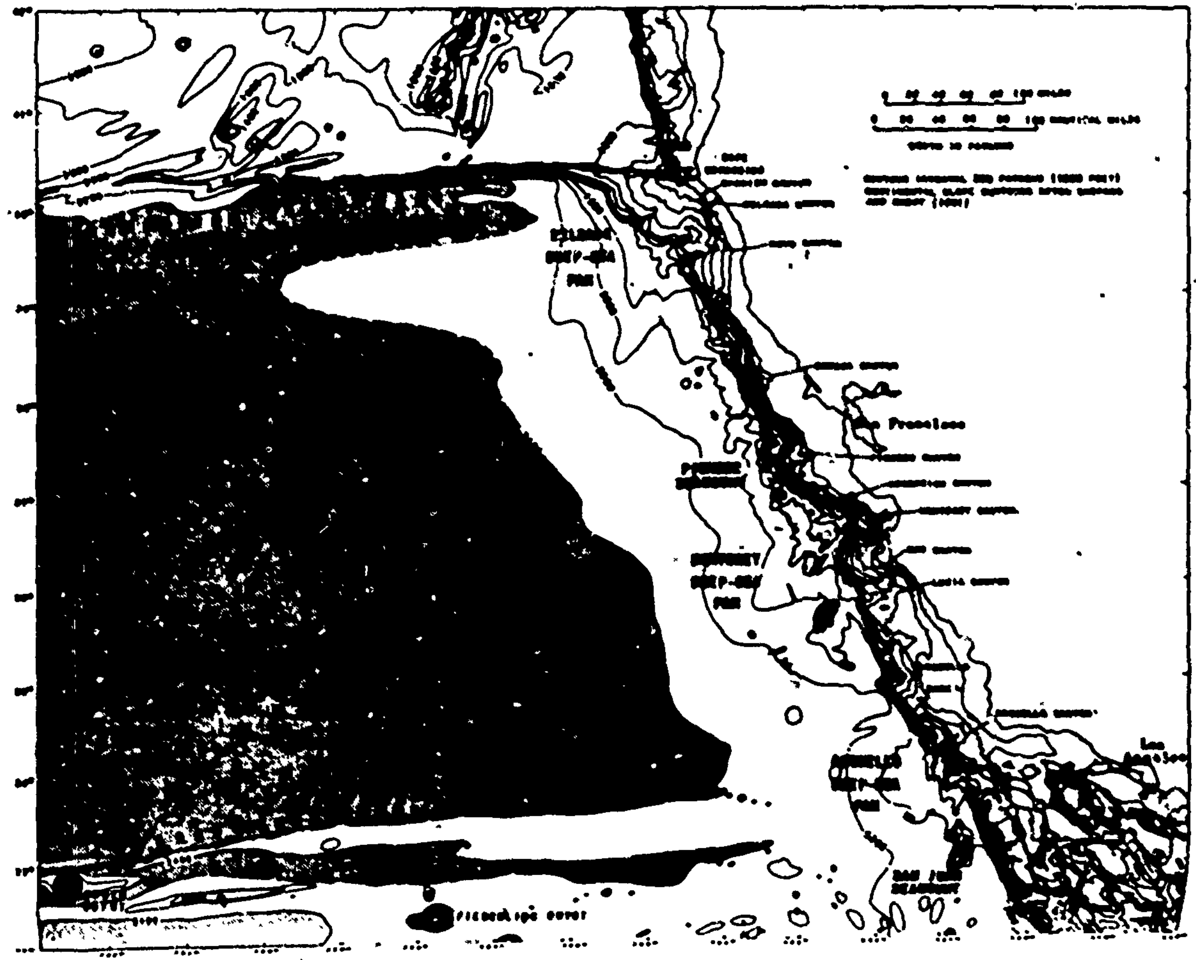


FIGURE 6.—Principal morphologic features of the sea floor off central California (from Rusnak, 1966; after Shepard and Emery, 1941).
Source: *Final Environmental Statement*, Bureau of Land Management, p. 265.

The continental margin of central and northern California contains six structural basins which are extensions of onshore basins and contain rocks of Tertiary age. From south to north these are: Santa Maria, Outer Santa Cruz, Santa Cruz, Bodega, Point Arena, and Eel River basins. All six of the basins are floored by Mesozoic igneous, metamorphic, or sedimentary rocks. Total sediment thickness varies from around 3,050 meters in the Santa Maria basin to over 6,100 meters in the Santa Cruz basin. Tertiary sections of over 3,000 meters are found in all of the basins with the Miocene being the thickest of the Tertiary units.[55]

The offshore Santa Maria Basin appears to contain excellent continuations of onshore stratigraphic, lithologic, and structural trends. There is production onshore, primarily from fractured Miocene shales but also from fine-grained lenticular Pliocene sands. Cumulative petroleum production to January 1973 was 609 million barrels. This was achieved by dense exploratory drilling, close well spacing, and expensive well treatments due to the high density of the crude oil. The potential reservoir strata are limited in the southeastern one-third of the basin and most of the remaining area contains a thin, poorly-known Teritiary section and water depths often exceeding 450 meters.[56]

Hydrocarbon shows onshore in the Bodega and Santa Cruz Basins have not been significant. The most promising potential reservoir strata and structural traps have been tested with results that suggest that these sections have low hydrocarbon potential.[57]

The Eel River Basin contains numerous large geologic structures and a thick marine shale section. There are also indications of local shale flowage and diapir structures. Miocene marine clastic strata extend offshore and probably contain reservoir quality sandstone. Pre-Miocene strata appear to have poor potential for petroleum production. Onshore production has yielded 56 billion cubic feet of gas (about equivalent to 10 million barrels of oil) from thin, lenticular, very fine-grained Pliocene sands. Minor quantities of oil have been produced from the Mesozoic. Total discovered gas reserves onshore are estimated at 80 billion cubic feet or 14 million barrels of equivalent oil.[58]

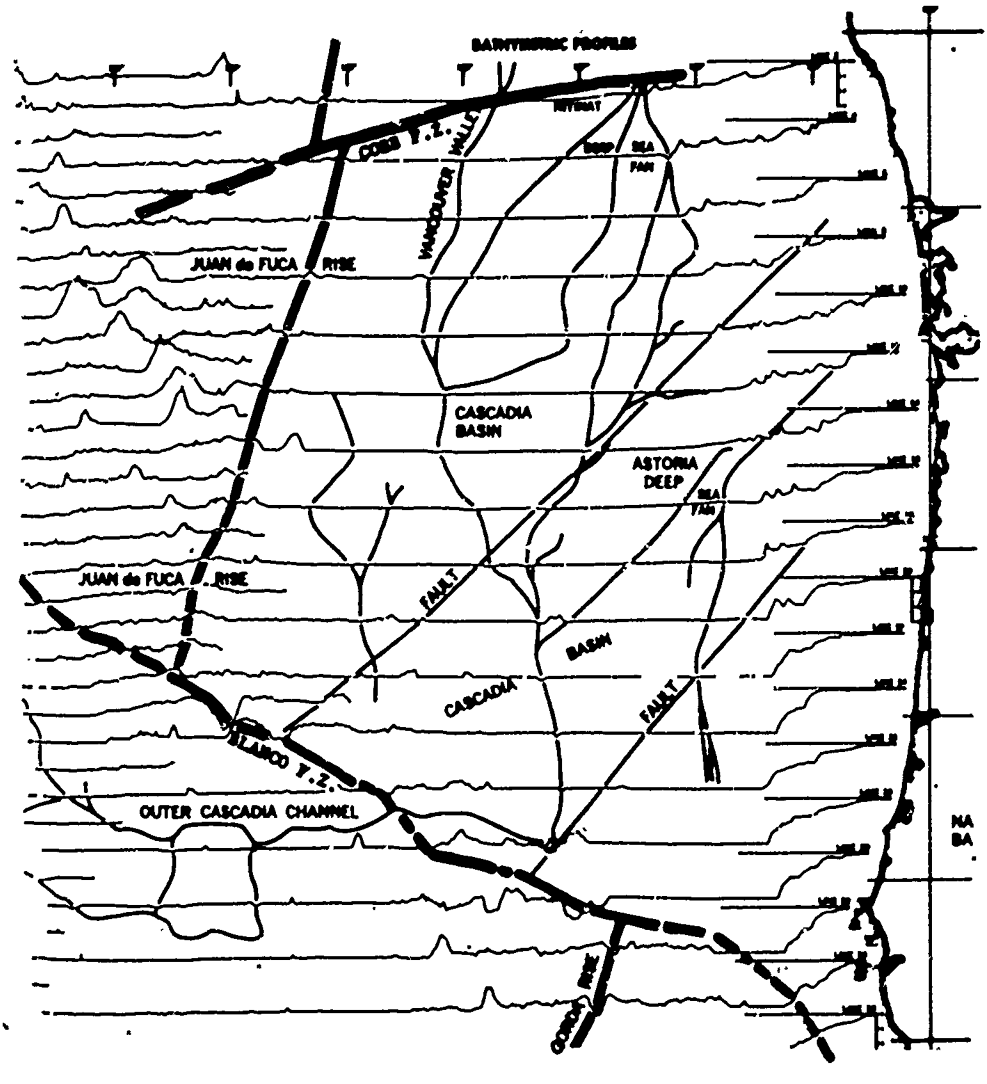
Only limited hydrocarbon indications have been found offshore, but, the Eel River Basin is largely untested and appears to have good potential especially for gas. The most attractive strata, however, lie mainly beneath the western two-thirds of the basin where water depths exceed 460 meters.[59]

The continental margin off Oregon and Washington represents the western part of a Tertiary depositional trough which at one time extended north-south from what is now Vancouver to the Klamath Mountains. The width of the trough is measured from the Cascade

[55] Ibid., p. 388.
[56] Ibid., p. 395–396.
[57] Ibid., p. 395.
[58] Ibid.
[59] Ibid.

Mountains on the east to the base of the present continental slope on the west. Two prominant subsea features, the Cobb and the Blanco Fracture Zones, represent the approximate natural offshore boundaries on the north and south, respectively.[60] (See Figure 7.)

FIGURE 7.—Geomorphic Features of the offshore Oregon and Washington area.



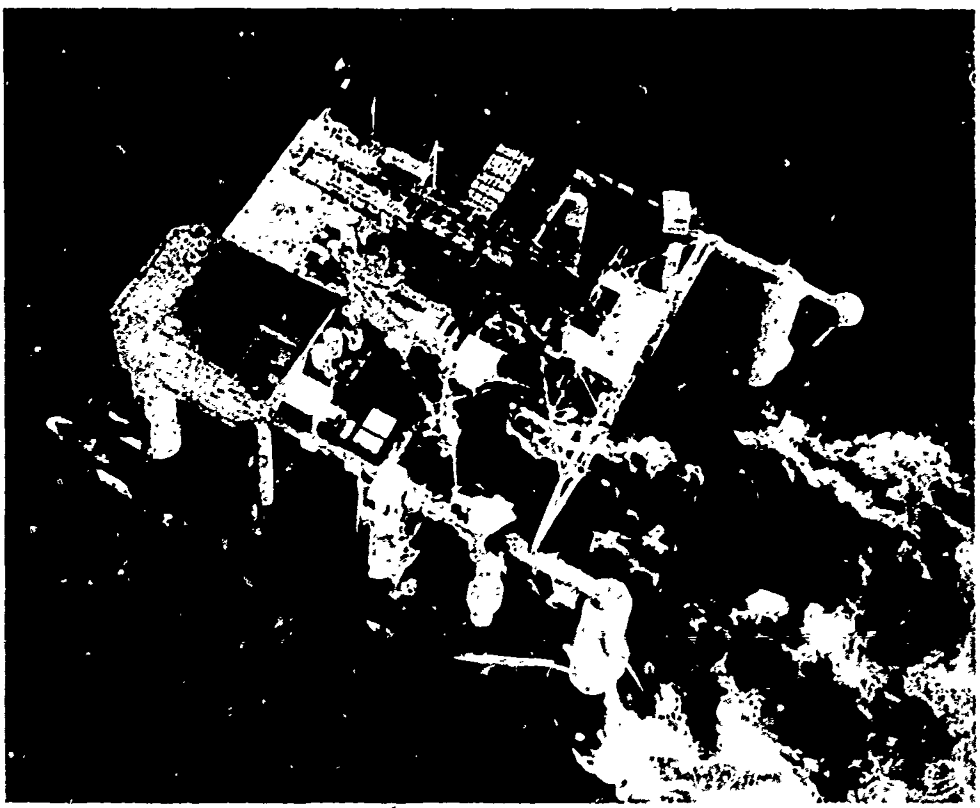
Source: Final Environment Statement, Bureau of Land Management, p. 294.

The oldest rocks in the depositional basin are early Eocene volcanics which make up the basement (the subsurface boundary) upon which the potential oil and gas strata may lie. The entire Tertiary basin sequence is thought to overlie the oceanic crust, although late Cretaceous deposits are exposed along the southern margin and may also be present in the trough. Within the basin, the middle to late Tertiary section generally consists of a marine sandstone and siltstone sequence

[60] "Final Environmental Statement, Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf," U.S. Department of the Interior, Bureau of Land Management, Volume 1, July 7, 1975, p. 293.

up to 7,625 meters thick with occasional interbedded non-marine and volcanic rocks. Offshore drilling in central Oregon has penetrated over 3,660 meters of Late Eocene to Recent rocks. Because of the limited well data and the thick overburden of Holocene sediments, estimates of the nature and distribution of the Tertiary strata offshore Washington are largely speculative.[61]

The depositional history of this structural province has been complicated by periodic volcanism accompanied by several phases of tectonic uplift and subsequent erosion. The latest period of major crustal uplift occurred during the Late Tertiary and Early Quaternary periods elevating the thick Tertiary sedimentary section into what is now the Coast Range. Structurally, the Coast Range is a broad regional upwarp consisting of numerous alternating structural ridges and troughs. These folds continue offshore where some of the ridges involve Quaternary strata and form bathymetric highs. The Late Tertiary strata are cut by numerous shale diapirs on the Washington and the western one-half of the Oregon Continental margin.[62] Oil and gas seeps have been reported from the coastal area of the Olympia Peninsula of Washington along with petroliferous muds. The petroliferous muds are found in the vicinity of the mouth of the Hoh River as well as further north along the coast.



Semi-Submersible drilling rig "Ocean Traveller" used in the North Sea in route through English Channel.

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[61] Ibid., p. 295.
[62] Ibid., p. 297.

The onshore hydrocarbon production in Oregon and Washington has not been commercially significant, but the thicker Late Tertiary sequence found offshore may hold more promise.[63] Mid to Late Tertiary sandstone strata which outcrop onshore probably occur in the subsurface beneath the continental shelf. Limited offshore drilling and seismic surveys have revealed diapiric shale off both Washington and northern Oregon. In general, these data suggest that the potential for structural and stratigraphic traps is good in the areas surveyed. About a dozen dry holes have been drilled offshore from Washington and Oregon. A more complete appraisal of hydrocarbon possibilities offshore Oregon and Washington must await the accumulation of additional geophysical and test well data. However, in 1974 no drilling or geophysical activity was reported in Oregon and less than one crew-month of offshore gravity and magnetic surveys was reported for Washington.[64]

Pacific Continental Shelf Reserve Estimates.—The demonstrated offshore oil and gas reserves of the Pacific coast to 200 meters are 1.116 billion barrels of oil and 463 billion cubic feet of gas.[65] In February 1974, the U.S. Geological Survey estimated the undiscovered recoverable oil and gas liquids of the Pacific shelf to a water depth of 200 meters to be from five to ten billion barrels and the undiscoverable natural gas reserves to be from ten to 20 trillion cubic feet. Mobil Oil estimated undiscovered Pacific shelf reserves of oil and gas liquids to be 14 billion barrels and undiscovered gas reserves to be 69 trillion cubic feet.[66] In June 1975, the U.S. Geological Survey revised their earlier estimates downward. The undiscoverable resources estimates for the Pacific outer continental shelf were reduced to a range of from two to five billion barrels of oil and from two to six trillion cubic feet of gas. The low value of the range is the amount associated with a 95 percent discovery probability and the higher amount is the quantity associated with a five percent discovery probability. The undiscovered recoverable natural gas liquids were estimated at 100 million barrels.[67]

As in the Atlantic and in the Gulf of Mexico, the volume of oil and gas expected to be discovered has recently been revised downward. The procedures used in the most recent U.S. Geoolgical Survey study take fuller account of the specific oil and gas prospects in each area. The earlier work of the Geological Survey resulted in estimates based mainly on the assumption that an equivalent volume of unexplored sediments would contain 50 to 100 percent as much petroleum as similar explored sediments. The newer conservative estimates when viewed in terms of probabilities allow for the presence of larger hydrocarbon amounts, but their probability is lower.

An example of the range of undiscovered resource estimates possible depending upon the methods utilized is the recent projection by a Los Angeles consultant of future potential reserves of 23.3 billion barrels of oil and 16.2 trillion cubic feet of gas just off the coast of California alone.[68] The consultant noted that seaward from the Cali-

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[63] Ibid.

[64] Pfeiffer, D. H. "Developments in West Coast Area in 1974." The American Association of Petroleum Geologists Bulletin, v. 59, n. 8, August 1975, p. 1344.

[65] Miller, Betty M. et. al. "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States," op. cit., p. 28–31.

[66] West, Jim. "U.S. Oil-policy Riddle: How Much Left to Find?" op. cit., p. 27.

[67] Miller, Betty M. et. al. "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States." op. cit., p. 28–31, 45.

[68] McCaslin, John C. "California Shelf has Vast Reserve Potential." The Oil and Gas Journal, January 20, 1975, p. 115.

fornia tideland to the base of the continental slope is as area of 100,000 square kilometers containing 16 sedimentary basins. The basins cover 60,000 square kilometers and contain a volume 166,000 cubic kilometers of sediments. The shelf is less than ten percent explored with activity confined mostly to the coastal fringe of the Santa Barbara Channel and near the city of Los Angeles. Nevertheless, some 1.8 billion barrels of oil and some 1,200 billion cubic feet of gas have been produced from 4,400 exploration and development wells.[69] Reserves are estimated in this study at 4.5 million barrels of oil. The above high future potential reserve figures were derived by taking into account the volumes of prospective sediments, structural trends, California discovery rates, present California reserves, etc., and may be contrasted with the latest (and lowest) Geological Survey figures which are no longer calculated on the basis of equivalent volumes. The final determination as to which estimate is the more nearly correct must await much additional exploratory and development drilling on the California OCS.

Alaskan Continental Shelf.—Alaska is situated at the northern end of the American Cordillera, the continuous mountain system which extends along the entire length of western North and South America. Thus, Alaska is similar in geologic structure and physiography to other parts of this long mountain complex. Dynamic earth processes alter the region continually. The Gulf of Alaska-Aleutian chain area is one of the most earthquake prone areas of the world. Further north in Alaska, the problems of permafrost (permanently frozen ground) also demand attention. The areal distribution of permafrost is quite variable, ranging from isolated patches to broad areas. Most of the current permafrost in Alaska formed during the Pleistocene ice age and relict thicknesses exceeding 100 feet are common, while a maximum thickness of 2,000 feet has been reported in the Prudhoe Bay area.

In the southern coast area of Alaska, the Alaskan Pacific-margin Tertiary basin is a 1,450 kilometers long structural feature that roughly parallels the southern coast of Alaska between Cross Sound and Chirkof Island. The basin covers an area of about 103,600 square kilometers and is mostly offshore. It is underlain by a thick section of Teritiary continental and marine strata varying from Paleocene through Pliocene in age. The basin sequence includes a lower unit of well-indurated intensely-deformed early Tertiary rocks overlain by a less-altered section of mid to late Tertiary strata. The middle to late Tertiary rocks appear to have the best reservoir possibilities. Rocks of early Tertiary age where exposed are hard and tightly cemented and appear to have little reservoir potential. The average thickness of middle and late Tertiary rocks is 3,050 to 4,570 meters and their volume in the basin has been calculated to be 129,500 to 194,250 cubic kilometers.[70]

The Tertiary basin is subdivided into two petroleum provinces, the Gulf of Alaska Tertiary province to the east and the Kodiak Tertiary province to the west. Although stratigraphically similar, the two provinces display significantly different structural trends. The geologic

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[69] Ibid.

[70] Gryc, George. "Summary of Potential Petroleum Resources of Region 1 (Alaska and Hawaii)—Alaska." Future Petroleum Provinces of the United States—Their Geology and Potential., The American Association of Petroleum Geologists, Tulsa, Oklahoma, 1971, Volume 1, p. 61.

structure of the Gulf of Alaska province is characterized by east-trending features including fault types similar to those found onshore. Kodiak province contains structural trends at a 45 degree angle to those in the Gulf of Alaska province and also a nearshore zone of the high-angle faulting of the Aleutian structural system.[71] A Federal lease sale is planned for December 1976, featuring offshore tracts east of Kodiak Island.

Oil companies have drilled 26 dry holes since 1954 along the narrow shoreline between the mountains and the Gulf of Alaska. At least a dozen of these tests were drilled as deep as 3,050 meters and one went to 4,480 meters.[72] There has been one small success in the area, the shallow Katalla oil field, discovered onshore near Kayak Island in 1902. The field, now abandoned, produced a total of 154,000 barrels of oil from 22 wells which ranged in depth from 110 meters to 545 meters. The Katalla field does prove that there are hydrocarbons present in the province. Onshore, drilling locations are limited because of the Chugach Mountains and the subsurface geology is complex. However, recent seismic surveys run along the continental shelf offshore of Katalla and in other sections of the Gulf of Alaska have indicated the presence of well-defined geologic structures at least one of which appears to be as large as the Prudhoe Bay structure.[73]

Between Icy Bay and Kayak Island the Gulf of Alaska shelf appears to be composed of two basic types of geologic structures. The first is a series of asymmetric linear folds that trend northeast to southwest across the shelf. The second, a large, gently dipping arch between Kayak Island and the Bearing trough, parallels the coast. Between the arch and the coast is a broad downwrap (as much as 95 kilometers in width) within which there may be some local upwraping. To the west of this area, between Kayak and Middleton Island, there is a broad zone of complex structure which trend northeast-southwest. In general, the structural highs tends to be asymmetric and bounded by thrust faults on their southeast limbs.[74]

In the Gulf of Alaska, the Department of the Interior, working from nominations submitted by the petroleum industry, has selected 330 tracts covering about 1.8 million acres for a lease sale tentatively scheduled for late 1975 or early 1976. However, this sale may be delayed for from six months to two years as suggested by the draft environmental impact statement released for the area by the Bureau of Land Management. The statement predicts that a certain degree of risk potential is inherent in all of the Gulf tracts. Thus, the statement continues that it is conceivable that information obtained from pending environmental studies could provide a basis for additional stipulations for increased protection of the environment prior to the holding of the proposed sale. Also, such studies could result in the deletion of a tract or tracts prior to holding the sale.[75] Having made the above observations in a discussion of the alternatives to holding the sale, in the northern Gulf of Alaska, the Bureau of Land Management did not

[71] "Final Environmental Statement, Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf," op. cit., p. 347.
[72] Wilson, Howard M. "Big Plans on Tap for Two Alaskan Wildcat Areas." The Oil and Gas Journal, June 2, 1975, p. 106.
[73] Ibid. p. 109.
[74] Ibid.
[75] "Alaska Gulf Sale May Be 2 Years Away." The Oil and Gas Journal, July 7, 1975, p. 28.

make any specific recommendations; however, even if the Secretary of the Interior decided to go ahead with the sale as planned, the observations would provide ample argument for those opposed to the sale.[76]

The state government of Alaska has also requested a six months to two years delay of the Gulf of Alaska lease sale to allow more time to study the projected environmental, social, and economic impacts. The state maintains that, unlike the Beaufort Sea area, the Gulf of Alaska does not have onshore support facilities for dealing with large scale offshore production; and that the state government needs time for advance planning and also needs front-end impact funds and a sharing of bonus and royalty payments which now go exclusively to the Federal Government.

The Bureau of Land Management estimates that about a dozen fields are likely to be discovered in the northern Gulf with an average distance from shore of 35.4 kilometers. At assumed peak production, 22 platforms and a total of 800 producing wells are projected with 12 to 24 major pipelines, three offshore loading and storage terminals, and one liquid natural gas plant. According to the Bureau of Land Management estimate, it will cost the petroleum industry $5.645 billion to develop the area.[77] The U.S. Geological Survey estimates the undiscovered resources in the northern Gulf of Alaska to be 0.1 to 2.8 billion barrels of oil and 300 billion to 9 trillion cubic feet of gas. The lower estimate is considered recoverable at a 95 percent level of confidence and the higher amounts at a 5 percent level of confidence.[78]

Of particular environmental concern in this area is the problem of earthquakes, since numerous earthquakes of significant magnitude have occurred since 1899. The sale area is classified as extremely susceptible to earthquakes of 6 to 8.8 (on a Richter scale to 10) magnitude with even more intense quakes likely to occur once in every 20 to 25 years.

The Supreme Court has cleared the way for the Federal government to lease Lower Cook Inlet off the Gulf of Alaska by a six to two vote ruling that the U.S. and not Alaska owns the leasing rights to the land beneath the lower inlet. The high court ruling reversed two lower court decisions. The Department of the Interior has indicated that the oil industry will be requested to express their interest in leasing the area. At least one year is normally required to hold a sale, if one is approved, as an environmental impact statement would have to be prepared and public hearings held in advance of the bidding. No sale had been scheduled in the Lower Cook Inlet pending the outcome of the Supreme Court's deliberations.[79]

Cook Inlet is an elongate, northwest trending coastal embayment in south central Alaska, east of the Alaska Peninsula. The Inlet is about 137 kilometers wide and 370 kilometers long with a water depth averaging less than 90 meters, but increasing southward to over 180 meters at the mouth of the estuary. Bottom sediments are fine-grained silt and clay from rivers which drain the rugged, glacial terrain which surrounds the Inlet. Cook Inlet is both a topographic and structural basin that contains about 18,000 meters of Mesozoic and Cenozoic sedi-

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[76] Ibid.
[77] Ibid.
[78] Ibid.
[79] "U.S. Given Rights to Lease Lower Cook Inlet." The Oil and Gas Journal, June 30, 1975, p. 52.

mentary rock. The older Mesozoic strata, which crop out around the edge of the basin, are mostly of marine origin, while the thick younger Tertiary rock sequence is largely non-marine. The basin is bounded by faults which parallel the northerly structural grain of the region. The structural ridges within the basin are aligned similarly and many of these anticlines are associated with long, parallel reverse faults. All of the oil and some of the gas discovered in the upper Cook Inlet fields have been in structural traps occurring along these trends.[80]

The Cook Inlet basin represents the southern part of the 38,850 square kilometer Cook Inlet petroleum subprovince, which also includes the Susitna Basin to the north. About one-third of the Cook Inlet subprovince has been explored by drilling, while the Lower Cook Inlet, covering an additional third of the total subprovince, is essentially unexplored. Available data indicate that the Lower Inlet has a thinner stratigraphic and also less structural potential than Upper Cook Inlet. However, promising structures are present and the erratic distribution of non-marine Tertiary strata within the sedimentary sequence suggests that stratigraphic traps could also exist throughout the basin.[81] The U.S. Geological Survey places the undiscovered resources of the Lower Cook Inlet at 0.5 to 2.4 billion barrels of oil and 1.0 to 4.5 trillion cubic feet of natural gas. The lower amount is that judged to be discoverable and recoverable at a 95 percent level of confidence and the higher amount that judged recoverable at a five percent level of confidence. When it appeared that the State of Alaska would win the rights to the lower inlet, the state and Federal governments began negotiating an agreement for joint leasing. Four sales, with one each year from 1975 to 1978 were being considered. When it became apparent that the Supreme Court would make a quick decision on the ownership issue, the agreement was dropped.[82]

Lower Cook Inlet lies within the seismically active zone of southern Alaska and at least 12 major earthquakes (magnitude greater than Richter scale 6) have occurred in the local area since 1899. Although the eastern half of Cook Inlet is located within the area of major tectonic deformation associated with the 1964 Prince William Sound earthquake, the existing oil and gas wells were not appreciably disturbed. Fissured ground, mud and landslides, and intense ground movements were widespread, however, and could pose potential hazards to future offshore oil and gas development during periods of seismic activity. Augustine Island, an active volcano located in southwestern Cook Inlet, represents a potential volcanic hazard to future oil and gas operations within the Lower Inlet. Of the five volcanoes that occur in the vicinity of western Cook Inlet, three have erupted during the last 21 years, causing local damage from ash falls, sea waves, and flooding.

The southern Aleutian Shelf forms a narrow arcuate zone that occurs between the Aleutian Islands—Alaskan Peninsula on the north and the Aleutian Trench on the south. The width of the shelf varies from less than 80 kilometers west of Unimak Island to about 240 kilometers near Kodiak Island in the east. The main shelf area is char-

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[80] "Final Environmental Statement, Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf." op. cit., p. 351.
[81] Ibid. p. 352.
[82] "U.S. Given Rights To Lease Lower Cook Inlet." op. cit., p. 52.

acterized by the presence of broad plains dissected by relict glacial drainage channels. The regional slope is generally less than 0 degrees 5 minutes. The shelf break is very distinct and occurs in waters from 120 to 130 meters deep off Unimak Island and in 150 to 160 meters depth waters off Kodiak Island. Beyond the continental shelf the steep, rugged continental slope drops more than 5,000 meters to the Aleutian trench over a horizontal distance of 30 to 80 kilometers. The tertiary sedimentary rocks of the Kodiak Tertiary petroleum province extend westward beneath the South Aleutian Shelf to the vicinity of Chirikof Island. Seismic data covering the western shelf is available, but, in general, insufficient lithological information exists to allow a meaningful evaluation of the resource potential. Both seismic and volcanic risk is considered high in the area.[83] Tentative plans exist for a lease sale in the Gulf of Alaska—Aleutian Shelf area in October 1978.

The Bristol Bay OCS area occurs within the large Bristol Bay basin which is a structural and sedimentary trough bounded by the Alaska Peninsula arch and the related Bruin Bay fault on the southeast and by the Goodnews arch and its seaward projection on the northwest. Exposures of highly-deformed, locally intruded Paleozoic and Mesozoic rocks mark the northeastern margin of the basin and its southeastern extension terminates with the continental slope. The northeast region of the Bristol Bay basin contains from 610 to 4880 meters of non-marine and shallow water marine Tertiary rocks while the central province is distinguished stratigraphically by a thin eastern nonmarine sequence that thickens southwestward to over 3660 meters while becoming more marine in character. Structural deformation in the sedimentary sequence of the Bristol Bay Basin is most pronounced along the western flank of the Alaska Peninsula arch, but extensive faulting has also occurred in the volcanic basement of the central Bristol Bay basin. These features, however, do not appear to extend into the overlying beds. The Mesozoic strata to the southwest have been faulted and broadly folded out to the edge of the continental slope, while the overlying Tertiary section is only mildly deformed. Large commercial quantities of hydrocarbons may be anticipated in structural and stratigraphic traps in the wide belt of transition between the marine Tertiary section in the southwest part of the basin and the non-marine Tertiary section in the northeast. Other accumulations are expected in the marine Mesozoic rocks of the southwest. An estimated one to two million acres of the Bristol Bay shelf region may have petroleum potential.[84] Nine test wells with minor oil shows have been drilled onshore, but none offshore. The best possibilities for large petroleum accumulation are likely to be located offshore.[85] A lease sale is projected for the outer Bristol Basin in December 1977. The potential geologic hazards in the region primarily involved seismicity and permafrost Sporadic volcanic activity along the southern coastal areas could exert a local influence.

Nearly half of the Bering Sea is underlain by a relatively smooth continental shelf which forms the southern part of the large Bering-Chukchi platform. The Bering shelf section in some areas extends offshore over 645 kilometers. Water depths over the Alaskan Bering

[83] "Final Environmental Statement, Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf," op. cit., p. 351.
[84] Ibid. p. 357.
[85] Gryc, George. op. cit., p. 60.

Sea shelf average around 55 meters. The shelf is virtually flat, but terminates abruptly seawards at about 160 meters water depth to one of the steepest known continental slopes. The irregular slope drops quickly, at average declivities commonly exceeding 20 degrees, from the shelf break to the 3,800 to 3,900 meter depth of the Bering Sea basin. There are several islands in the Bering Sea, many of which are composed of thick accumulations of volcanic flows and debris interbedded with sedimentary strata.

Acoustic reflections indicate a generally thin cover of Holocene sediments overlying the southeast Bering Sea shelf. Holocene sediments vary in thickness from zero to ten meters, the average being three meters. The unconsolidated Holocene sediment cover over the northeast Bering Sea shelf is also thin, but more variable in thickness. The predominant sediment type in the area is fine sand in contrast to the even finer-grained bottom constituents of the Chukchi Sea to the north. Most of the Holocene sedimentation along the eastern Bering shelf apparently has occurred at delta fronts of the major coastal rivers. There has been relatively little redistribution of this material across the shelf.

The Bering Sea OCS area contains several sedimentary and structural basins which contain Cenozoic sediments. The Norton Basin, covering an area of about 100,000 square kilometers, extends from the shores of Norton Sound westward to Cape Chukotsky and between the Seward Peninsula on the north and St. Lawrence Island to the south. This basin contains up to 2,000 meters of marine and nonmarine Cenozoic strata that is similar to the Bristol Bay basin sequence to the southeast. The Pribilof, St George, Zhemchum, Navarin, and other similar but unnamed basins are elongate outer-shelf basins of broadly deformed and faulted marine deposits which parallel the northwest trend of the margin of the shelf. The inner-shelf Norton and Bering Sea basins represent large structural sags. Many of the outer-shelf basins appear to be fault controlled.[86]

Petroleum prospects on the Bering Sea OCS include: the basins containing thick sections of Cenozoic and, in some areas, Cretaceous sediments; the deformed Mesozoic which underlie many of these basins; the dome and diapiric structure associated with the more deeply submerged (2,000 meters) Umnak plateau area; and, the thick masses of Late Tertiary beds in summit basins along the crestal region of the Aleutian ridge.[87] The most promising prospects appear to be the thick accumulations of Early Tertiary through Holocene strata that are present in the larger inner-shelf basins which underlie the shelf's major bays and gulfs such as the Norton Basin. Many of the outer-shelf basins are underlain by folded Cretaceous and Jurassic strata which may be prospective in themselves and also may have supplied hydrocarbons to the overlying Cenozoic structures. Other promising areas are the rather large (some as much as 30 by 80 kilometers) summit basins of the 2,200 kilometer long Aleutian Ridge. These basins are roughly rectangular in shape and elongated parallel to the ridge. The floors of the two of them, the Amukta and the Amlia basins, lie in water about 1,000 meters deep and are underlain by a

[86] "Final Environmental Statement, Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf," op. cit., p. 358–360.
[87] Ibid. p. 360–361.

three to four kilometer thick Late Tertiary sedimentary sequence. These basins are bordered by major normal faults and are also disrupted along high-angle growth faults.[88]

A Federal lease sale has been tentatively scheduled for the St. George Basin in the Bering Sea shelf area in March of 1977. A second Federal lease sale has been tentatively scheduled for the Norton Basin area of the Bering Sea in August 1978. The Bureau of Land management has called for tract nominations for the St. George Basin sale.

The Chuckchi Sea is located off the Alaskan arctic coast and extends northward between Wrangel Island and Point Barrow to the edge of the continental shelf. The underlying Bering-Chukchi platform joins the North American and Asian continents. Water depths over most of the shelf are generally less than 55 meters, 40 meter depths commonly occur 50 to 100 kilometers of the coast. Kotzebue Sound, a large, shallow coastal bay, is the dominate feature of the southeastern Chukchi coast. The Chukchi continental shelf is generally smooth with minor irregularities on its outer margin. A broad topographic high shoals at 13 meters to the north of the Bering Strait. To the west, a submarine canyon extends northward to the outer continental margin. Beyond the shelf, the continental slope descends from 65 meters water depth to about 180 meters. The continental rise is about 160 kilometers in width. Ice activity has resulted in an irregular distribution of sediment types on the Chukchi shelf. Most of the shelf is veneered with a coat of unconsolidated gravel, sand, and mud derived from the mixing of poorly-sorted ice-rafted debris with normal shelf sediments. Thicker deposits of fine-grained river derived sediment have accumulated in the Kotzebue Sound. In the adjacent Bering Strait, swift currents have removed the unconsolidated sediment cover.[89]

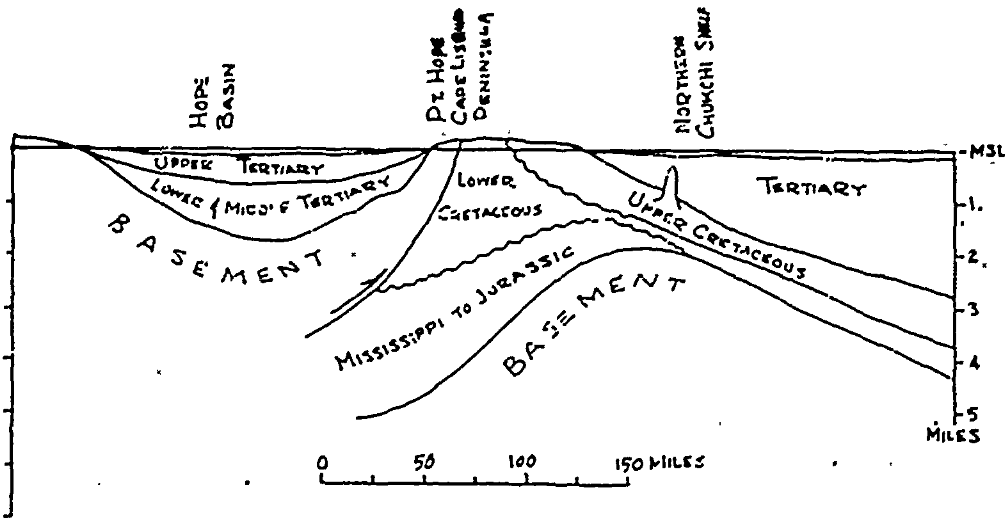
A subsurface structural ridge, the Barrow arch, extends northwest from Point Barrow then southwest across the northern Chukchi Sea, dividing it into two distinct terrains. A southward-thickening Mississippian to Jurassic sedimentary section extends between the Barrow arch and the northern foothills of the Brooks Range and its offshore extension. These older rocks are overlain by organic-rich Lower Cretaceous shales that are thought to have been the source of the oil trapped in the Prudhoe Bay field. Above these shale beds younger Cretaceous strata contain a major resource of sub-bituminous and bituminous coal and some oil and gas on the North Slope of the Brooks Range. They and the older rocks are bounded on the south by a zone of major trust faulting. Folding, related to the faults, dominates Cretaceous structure in the southern part of the northern Chukchi Sea. From the Barrow arch northward, a thick sequence of bedded rocks dips to the north from the arch to the continental slope. The upper beds in this sequence, probably Tertiary age, overlie the older rocks of probable Cretaceous origin. Several large diapir folds extend into the sequence, some piercing the entire section to the sea floor.[90]

The Hope Basin is a broad structural depression that underlies a large portion of the Chukchi Sea off Point Hope (See Figure 8). The basin was formed in Early to Mid-Tertiary time across a broad

[88] Ibid.
[89] Ibid. p. 362–363.
[90] Ibid. p. 363–364.

terrain of complex Paleozoic to Mesozoic sedimentary and volcanic rocks. The basin is most probably entirely clastic and of mixed marine and non-marine origin. The lower Tertiary sequence of up to 1,500 meters thick was later mildly faulted and folded. Subsequent deposition of a Pliocene to Pleistocene sequence reached a maximum thickness of about one kilometer.[91]

FIGURE 8



SCHEMATIC CROSS SECTION OF NORTH & SOUTH CHUKCHI SEA

Source: U.S. Geological Survey.

The northern Chuckchi Sea is underlain by some of the same geological strata and features which are present at Prudhoe Bay, the site of a super giant oil and gas field, and the Naval Petroleum Reserve 4 area, the site of several lesser oil and gas fields. Sedimentary deposits north of the Barrow arch may attain thicknesses of 6,000 meters or more. The possibility that they may represent a Late Cretaceous and Tertiary delta in combination with the presence of diapiric structures makes the area attractive for petroleum exploration. In the Hope Basin, the presence of a regional arch, many smaller folds, and numerous faults in the older sedimentary sequence, combined with a local erosional surface at the base of the younger sequence, offers good oil and gas trapping potential.[92]

Although much of the Chukchi Sea OCS has not been surveyed, potential geologic hazards are earthquakes, lack of bottom sediment stability, and bottom scour by polar pack ice. A federal lease sale in the Hope Basin area of the Chukchi Sea is tentatively scheduled for December, 1978.

The Beaufort Sea shelf off Alaska is relatively narrow, varying in width from about 97 kilometers in the west to about 48 kilometers in the east. The outer edge of the shelf lies beneath 50 and 70 meters of water. The shelf is dissected by several submarine valleys. The

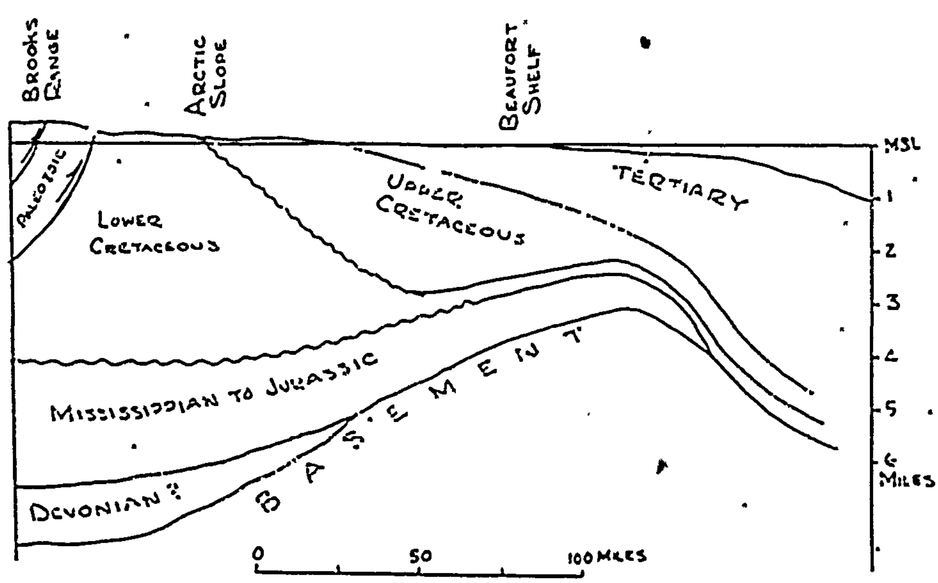
[91] Ibid.
[92] Ibid. p. 365.

Barrow Sea valley, the largest of the submarine valleys, trends northeastward off Point Barrow and extends across the shelf into the Arctic Ocean basin. Surface sediments on the Beaufort Sea shelf are composed of a poorly sorted mixture of mud, sand, and gravel with the gravel content being the highest along the outer margin of the shelf.[93]

The Beaufort shelf and slope are underlain by a progradational sequence of Cretaceous marine and non-marine sedimentary rocks that dips gently northward off the Barrow arch. On the east, the Cretaceous rocks are overlain by Tertiary marine and non-marine strata. Structures do exist in these rocks west of the mouth of the Canning River, but east of the Canning the rocks are thrown into folds with hundreds of meters of structural relief and, in some cases, tens of kilometers of strike length. A schematic cross-section from the Brooks Range to the Beaufort Shelf is shown in Figure 9.

The Cretaceous rocks beneath the Beaufort Sea probably contain organic rich shales at their base, as is the case onshore. The sands higher in the section contain both oil and gas deposits onshore near the coast. The possibility also exists that some of the pre-Cretaceous rocks which contain oil at Prudhoe Bay may locally extend across the Barrow Arch thus underlying the Beaufort shelf. While the Cretaceous and Tertiary rocks thicken seaward, the pre-Cretaceous rocks generally occur within shoreline facies along the Barrow Arch and thicken southward. A conservative estimate of onshore data suggests that if prospective pre-Cretaceous rocks are present on the Beaufort Shelf, they are of limited extent.[94]

FIGURE 9



Schematic cross section from Brooks Range to Beaufort Shelf

Source: U.S. Geological Survey.

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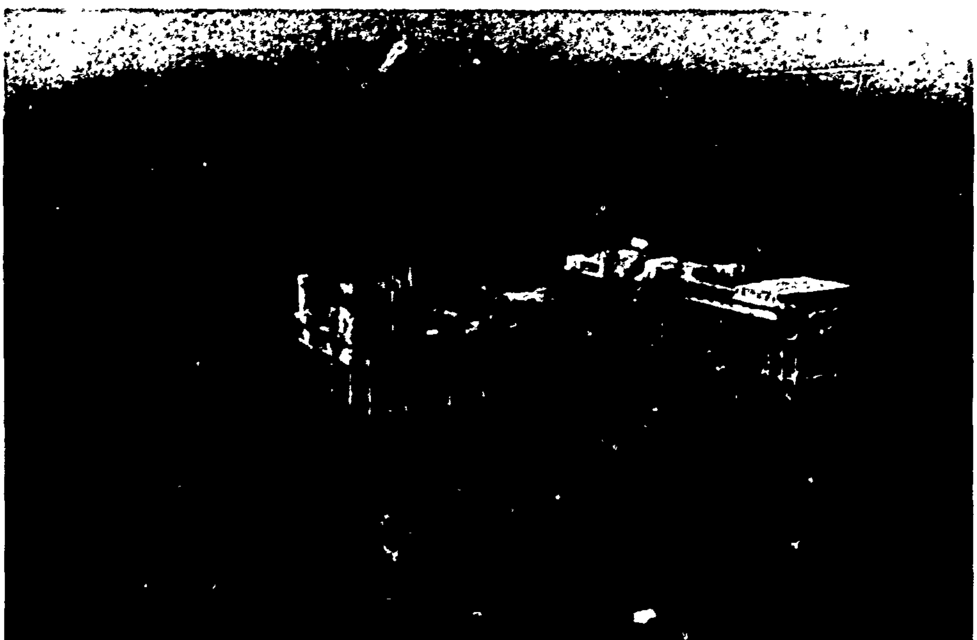
[93] Ibid. p. 367.
[94] Ibid. p. 368-370.

The offshore seismic records do appear to indicate, however, that the producing Permian-Triassic sand at the giant Prudhoe Bay field will probably occur north of the field beneath the shelf. This sand disappears at a fault line running northwest to southeast across Prudhoe and it has not been determined if it again appears at some point to the north. Wells recently drilled or planned in the waters of Prudhoe Bay may give some indication as to what is farther out, but this information will not be released because the tracts on which they are located lie adjacent to an area yet to be leased by the State of Alaska. It is not expected that another Prudhoe Bay field will be discovered offshore because the larger structures appear to be complexly faulted, thus making any oil difficult to find. The target to the north will be not only the Permian-Triassic sand, but also Mississippian-Pennsylvanian strata and the younger Cretaceous sands.[95]

It is also possible that there is favorable hydrocarbon potential to the northeast as well as due north of Prudhoe Bay. To the east the younger Mesozoic formations thicken though less is known about them. The area may be a gas province rather than an oil province as it lies in the direction of the Mackenzie Delta gas resources, located about 325 kilometers farther east.[96]



Offshore oil production platform off the Louisiana coast.

Courtesy Exxon Corporation.

Onshore exploration on the North Slope has led to two recent discoveries with possible implications for offshore hydrocarbon prospects. These discoveries have added to the reserves to be tapped by the trans-Alaska pipeline. One discovery was made three miles north of

[95] Wilson, Howard M. "Wildcatters Poised for Beaufort Sea." The Oil and Gas Journal, June 2, 1975, p. 100.
[96] Ibid. p. 102.

the Prudhoe Bay field on the shore of Gwydyr Bay in the same formation that is productive in the Prudhoe Bay structure. An earlier discovery of a new oil pool in the Prudhoe Bay field was directionally drilled out under the bay from an onshore site on the edge of Prudhoe Bay. Production from this pool will be derived from Upper Paleozoic strata lying below the Permian-Triassic sand which is the principal pay zone in the Prudhoe Bay field.[97]

The Prudhoe Bay field currently has three wells on production with a total output of about 6,300 barrels of oil per day. The oil is used to supply the needs in the development of the field. Cumulative production from the Prudhoe Bay field has been about 5.8 million barrels.[98]

The field is scheduled to have some 130 wells to provide an output of about 1.2 million barrels per day when it goes on stream sometime in 1977. The production at that time is expected to average out to about 9,000 barrels per day per well.[99]

Working to meet this goal, B.P. Alaska Inc. operator for the western portion of the field, has already drilled about 60 of the 70 wells that will be needed for its sector. In the eastern portion of the field, it is anticipated that about 60 wells will be needed when the field goes into production. Atlantic Richfield Co., operator of this eastern sector, has completed about 30 wells and is continuing the development drilling program.[100] The huge Prudhoe Bay field is estimated to contain reserves of about 10 billion barrels of oil.

The Navy's Petroleum Reserve Number 4, located at the northern tip of the United States just 58 kilometers west of the Prudhoe Bay unit boundary, is a largely unexplored untapped oil and gas province that may contain reserves rivaling the Prudhoe Bay area. The reserve was created by President Harding 52 years ago. With sporadic drilling during the past 30 years, the Navy has found a series of oil and gas fields. None, however, has been of commercial magnitude, by North Slope standards, except the small Barrow gas field which serves the local area. The Navy has recently decided to hire an oil company contractor to begin a systematic wildcat drilling effort. For the short term, the Navy has a 26 well program over the next seven years, a pace quite slow by industry standards.[101] The Navy hopes to increase the pace of exploration as the program advances, but realizes that future funding will depend in part upon the success of the early wells in the program. It has been estimated that the cost to explore and partially develop the reserve over a seven year period would be between $400 and $500 million.[102] Test well drilling from 1944 to 1953 found a number of small fields, none large enough to warrant development on the remote North Slope. The Simpson, Umiat, and Fish Creek fields, the largest of the finds, probably have reserves of about 100 million barrels. The Gubik gas field, which lies about two-thirds outside of the reserve, has about 141 billion cubic feet of gas. The Barrow field has about 12 billion cubic feet of gas still unproduced.[103] While the locations of the 26 wells have generally been decided, they have not as yet

[97] Alaska. Offshore. June 20, 1975, p. 117.
[98] "Prudhoe Bay Field Will Get 130 Wells by 1977 and 1.2 Million Barrels Per Day." Offshore, April 1975, p. 110.
[99] Ibid.
[100] Ibid.
[101] Wilson, Howard M. op. cit., p. 100.
[102] Ibid.
[103] Ibid. p. 110.

been announced as additional planned seismic and geologic work may alter the program. The Federal government has estimated that the undiscovered resources of the reserve are from ten to 33 billion barrels of oil and 80 trillion cubic feet of gas. This estimate is based mostly on the prospect of finding within the reserve the same hydrocarbon bearing formations which are productive at Prudhoe Bay. The unknown is, therefore, whether the sands are there and whether they contain oil and are producible. Much of the earlier drilling in the reserve has been to the Cretaceous rather than to the older Triassic, Permian, and Pennsylvanian which are productive in Prudhoe Bay. There are large Cretaceous structures in the reserve that will be tested, but the Cretaceous thins out in the northern part of the reserve and the older formations become shallower and will be tested early.[104]

The Navy has drilled a $7 million dry hole in its first effort to determine if the prolific Triassic-Permian Prudhoe Bay trend extends westward into the reserve. The well, which was spudded last March was found to be noncommercial in the Triassic-Permian and lower zones, but the upper formations are yet to be evaluated. There was disappointment that over this first time/failure to find major reserves in the zones that are productive at Prudhoe Bay, however it did take six years and 12 holes to find the large Prudhoe structure.[105]

A Federal lease sale in the Beaufort Sea is tentatively scheduled for October 1977. However, the State of Alaska has called for nominations and is planning a lease sale in the state waters of the Beaufort Sea for early 1976. The tracts to be leased will lie between the Canning and Colville rivers and will generally be inside the barrier island chain. A portion of the potential sale area covers acreage which has been claimed by both the State of Alaska and the Federal government. Some of this acreage lies close to Prudhoe Bay. The state and Federal governments are currently negotiating an agreement to lease the disputed acreage and place the revenue in escrow until ownership has been settled.[106] Much of the area covered by the sale can be slant drilled from the shoreline or from the barrier islands. Some of it however, would require drilling from the water or the frozen water surface.

Potential geologic hazards to drilling in the Beaufort Sea occur primarily in the nearshore zone. Here, coastal erosion, migration of longshore bars and barrier islands, sea ice grounding and scour, and the permafrost will affect drilling and the location of pipelines and shore facilities.

Alaskan Continental Shelf Reserve Estimates.—The demonstrated offshore oil and gas reserves of Alaska to 200 meters are 150 million barrels of oil and 145 billion cubic feet of gas.[107] In February, 1974, the U.S. Geological Survey estimated that the undiscovered recoverable oil and gas liquids of offshore Alaska to a water depth of 200 meters to be from 30 to 60 billion barrels and the gas reserves to be

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[104] Ibid. p. 112.
[105] "Navy's North Slope Test Dry." The Oil and Gas Journal, June 2, 1975, p. 47.
[106] "Alaska Pushes for Early Sale in Beaufort Sea." The Oil and Gas Journal, February 17, 1975, p. 36.
[107] Miller, Betty M. et. al. "Geological Estimates of Undiscovered Recoverable Oil and Gas Rsources in the United States," op. cit., p. 28–31.

from 170 to 340 trillion cubic feet. In contrast, Mobil oil estimated offshore Alaskan undiscovered oil and natural gas liquids at 20 billion barrels and undiscovered natural gas at 105 trillion cubic feet.[108] In June, 1975, the U.S. Geological Survey revised their earlier estimates sharply downward. The undiscovered recoverable oil resources to 200 meters water depth were given at between 3 and 31 billion barrels and the undiscovered recoverable gas resources to 200 meters water depth at between eight and 80 trillion cubic feet. The low value of the range is the amount associated with a 95 percent probability of discovery and the higher amount is the quantity associated with a five percent probability of discovery. Undiscovered recoverable natural gas liquids were estimated at 1.1 billion barrels.[109]

As is the case in the Atlantic, the Gulf of Mexico, and the Pacific coast areas, the estimated volume of the oil and gas resource remaining and expected to be discovered off Alaska has been recently revised downward by the use of more sophisticated methods. It should be emphasized, however, that all of the estimates of recent years, whether high or low, indicate that much more oil remains to be found offshore if exploration is encouraged. The oil and gas remaining in place is a large target for future development and the frontier areas are an important part of this potential.

Summary of the Oil and Gas Resources of the Outer Continental Shelf.—The production, reserves, and undiscovered recoverable oil, natural gas, and natural gas liquids for the U.S. outer continental shelf (to a water depth of 200 meters) as estimated by the U.S. Geological Survey in June, 1975, are summarized in Table 2.

TABLE 2.—OIL, NATURAL GAS, AND NATURAL GAS LIQUIDS RESOURCES OF THE U.S. OUTER CONTINENTAL SHELF (0 TO 200 METERS)

State	Cumulative production	Demonstrated reserves
Alaska:		
Oil (million barrels)	456	150
Gas (billion cubic feet)	423	145
Pacific Coast:		
Oil (million barrels)	1,499	1,11[illegible]
Gas (billion cubic feet)	1,415	463
Gulf of Mexico:		
Oil (million barrels)	4,135	2,262
Gas (billion cubic feet)	32,138	35,348
Atlantic Coast:		
Oil	None	None
Gas	None	None
Totals:		
Oil (million barrels)	6,090	3,528
Gas (billion cubic feet)	33,976	35,956

[108] West, Jim. "U.S. Oil-policy Riddle: How Much Left to Find?" op. cit., p. 27.
[109] Miller, Betty M. et. al. "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States," op. cit. p. 28–31, and 45.

TABLE 2.—OIL, NATURAL GAS, AND NATURAL GAS LIQUIDS RESOURCES OF THE U.S. OUTER CONTINENTAL SHELF (0 TO 200 METERS)—Continued

	Undiscovered recoverable resources	
	Statistical mean	Estimated range (95 percent to 5 percent)
Alaska:		
Oil (billion barrels)	15	3–31
Gas (trillion cubic feet)	44	8–80
Gas liquids (billion barrels)		1.1
Pacific Coast:		
Oil (billion barrels)	3	2–5
Gas (trillion cubic feet)	3	2–6
Gas liquids (billion barrels)		0.1
Gulf of Mexico:		
Oil (billion barrels)	5	3–8
Gas (trillion cubic feet)	50	18–91
Gas liquids (billion barrels)		1.3
Atlantic Coast:		
Oil (billion barrels)	3	[1] 2–4 [2] 0–6
Gas (trillion cubic feet)	10	[1] 5–14 [2] 0–22
Gas liquids (billion barrels)		0.3
Totals:		
Oil (billion barrels)	26	[2] 8–50
Gas (trillion cubic feet)	107	[2] 28–199
Gas liquids (billion barrels)		2.8

[1] 75 percent to 25 percent
[2] 95 percent to 5 percent.

These latest U.S. Geological estimates are the product of the analysis of a large amount of fundamental data by geologists on the Survey staff. Sufficient data have been collected and analyzed to provide a balanced estimate of domestic oil and gas resources. These Survey resource estimates are, of course, subject to revision as the methods are improved, more complete and reliable data are acquired, technologies change, economic conditions change, and as deeper water areas are incorporated into the appraisals. The uncertanties involved in estimating undiscovered recoverable resources are emphasized by the Survey in their use of a range of values representing on the one hand a 19 in 20 chance that there is more than the low value, but a one in 20 chance that there is as much as or more than the high value. The survey estimates are conservative, they do not include resources in water depths greater than 200 meters, they do not consider improvements in the historical average of 32 percent recovery of in-place oil, and they do not allow for higher prices for oil and gas.

There are five methods of resources estimation which are commonly used. They are: the sediment volumetric method, the geologic parameter analysis and analog extension method, the probalistic exploration-engineering analysis, the analysis of production and reserve data, and the analysis of discovery index and exploration success.

The sediment volumetric method is a projection of the amount of oil from a known and developed area to an unknown area of similar rock volume and characteristics. This type of projection frequently leads to resource estimates that appear overly optimistic.

The Probabilistic exploration-engineering analysis, as used by Mobil, can be employed only in areas where sufficient data are available.

Estimates of future potential are based on geological and engineering data and are derived for each oil and gas trend in each sedimentary basin, using a probabilistic model. Computer input for basin resource estimation uses a Delphi-like approach in which input estimates are challenged to bring out the basis of the estimates and to improve their quality. Crucial parameters such as the prospective area of a stratigraphic unit, the percentages expected to be productive, the thickness of a potential pay zone, and the recovery per acre foot are expressed as cumulative probability curves or risk profiles. Future potential probability curves are obtained by a simulation process involving random sampling from probability curves of various basic data. From this, many possible combinations of these various inputs are obtained and result in a probability distribuiton of future potential for a given area. The result is an idea of the risk and the chances of a higher or lower value for future potential other than the expected volume.[110]

Where the data are sparse or lacking, the probabilistic method can be used in combination with the geologic parameter analysis to estimate potential resource estimates by extrapolation. Geologic parameter analysis attempts to relate to resource estimation such data as structural characteristics, the environment of deposition of source and reservoir rocks, the timing of desposition and trap formation, and the geometry of the basins. These basic parameters can be applied in analog extrapolation.[111]

The analysis of production and reserve data and the analysis of the discovery index and exploration success are both indicators of undiscovered resources. A decline in any of these parameters could signal a declining resource base.

In any consideration of undiscovered hydrocarbon resources, however, the practical question is how much oil and gas can be found, rather than how much is left to be found. An uncaptured resource provides no benefits. It may be that more undiscovered oil and gas exist in the nation's historic non-frontier regions than in the OCS. However, the chances of finding large fields in these older provinces are small. (Only five fields of over 100 million barrels of oil or gas equivalent have been found onshore in the lower 48 states by the 38,000 exploratory wells drilled in the last five years).[112] The attractiveness of the OCS is the possibility that it may yield oil in larger accumulations and, in this sense, the oil may be found and translated to large volume production sooner than in the picked over provinces onshore.

TECHNIQUES TO LOCATE OIL AND GAS IN OFFSHORE AREAS

Most of the information used by both the Federal government and the oil industry concerning the oil and gas potential of various OCS areas is acquired by geological and geophysical surveys. A permit must first be obtained from the Area Oil and Gas Supervisor of the U.S. Geological Survey before any exploratory activity may be undertaken on the OCS. Much of the geophysical surveying done under permit

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[110] "World Crude Resource May Exceed 1,500 Billion Barrels." World Oil, September 1975, p. 56.

[111] Ibid.

[112] Drummond, Jim. "The IADC Meeting in Dallas." The Oil Daily. Sept. 22, 1975.

is accomplished by specialized data collection firms which sell or furnish the information to oil companies and to the Department of the Interior. The only method of locating hydrocarbons with certainty, however, is by exploratory drilling.

Geological Activity.—Geological exploration of the outer continental shelf consists of bottom sampling, shallow coring, and, in some cases, deep stratigraphic test drilling. Usually, bottom sampling and shallow coring are conducted simultaneously using a small marine drilling vessel. Bottom samples are obtained by dropping a weighted tube to the ocean floor and recovering it by means of an attached wire line. Penetration is usually limited to a few feet, depending upon the nature of the local ocean floor. The samples obtained in this manner are useful in identifying the type and origin of the bottom. If the bottom formation is composed of sedimentary rock, its geologic age can often be determined by the identification of fossils included in the sample.

Shallow coring is performed by conventional rotary drilling equipment, but the choice of location is carefully controlled to avoid hazards to the environment. Penetration is usually limited to the recovery of several feet of consolidated rock. The geological examination of the cores provides useful data regarding the general geology of the area.

Deep stratigraphic tests are drilled for the acquisition of geological and drilling information and may be as deep as 4,800 meters. Geological survey rules require that stratigraphic tests be drilled on off-structure locations and that no testing for oil and gas be permitted. Also, the geological data obtained from the test must be released within 60 days after the first lease sale in the area. By the use of various well logging devices and an examination of the drill cuttings and cores, the geological section can be determined. Potential source and reservoir rocks can also be studied which, in a general way, are indicators of the extent of possible discoveries in adjacent structures.

Geophysical Activity.—Seismic exploration provides additional information at all depths by measuring the velocity of shock or seismic waves through various rock formations beneath the seabed. The shallow information is of value in the identification of potentially hazardous conditions such as surface and near surface faulting, potential slide areas, or shallow gas pockets. Information of this kind is valuable in the choice and approval of drilling and platform locations.

For regional and detailed mapping, deep penetration seismic information is needed. Geophysicists interpret these data by mapping at least two seismic reflections corresponding to the depth of expected hydrocarbon production. The seismic maps show the types of structures (salt domes, folds, faults, etc.) that appear likely to be present in the area. Geophysical data, along with the geological data, are used by the oil industry in nominating tracts for lease and in preparing bids for lease sales. The Geological Survey uses this information for general sale area identification, tract selection, resource evaluation, and lease management.[113]

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[113] Adams, M. V., John, C. B., Kelly, R. F., LaPointe, A. E., and Meurer, R. W., "Mineral Resource Management of the Outer Continental Shelf." Geological Survey Circular 720, Reston, Virginia, 1975, p. 9.

In exploration seismology, energy is transmitted into the earth and the recorded reflections provide information about the subsurface which can be used for the delineation of geological structures. The most common sources of energy for offshore seismic surveying are air or gas guns which generate the seismic waves without the use of explosives. An array of guns of various sizes provides sufficient energy to penetrate over 6,000 meters of sediments in most areas. The geophones that detect the reflected seismic energy are very sensitive instruments enclosed in a cable up to 2,700 meters long which is towed behind a survey ship. The cable is a thick flexible tube which contains geophones and the wires to carry the seismic information to the recorders aboard the ship. It is filled with oil to provide buoyancy and better acoustic coupling with the water and is fitted with stabilizers to control its depth below the surface. The equipment on board the ship records the seismic signals on magnetic tape in digital format. These field data are then processed in a digital computer to eliminate unwanted "noise" or random energy. After the data have been processed to obtain maximum quality, they are displayed in the form of a vertical cross section which exhibits geological structure.

Seismic reflections are caused by velocity changes in the rock formations. The greater the velocity difference between two geologic horizons, the greater the amplitude of the reflected energy. Since the velocity in a gas or oil saturated sandstone is lower than in either a water saturated or nonporous sandstone, the presence of oil or gas in the formation will cause a two to five fold increase in the amplitude of the reflected energy. By recording and processing such seismic data in a manner that preserves the true amplitudes of the reflections, it is sometimes possible to directly identify gas or oil bearing sands. These specially processed seismic data, when displayed on cross sections, show strong events when abnormally large contrast in rock velocities exist. These strong events are referred to as "bright spots" hence the name for this method of direct hydrocarbon detection. A second indicator of hydrocarbons is the polarity of the reflected seismic wave. Seismic waves are transmitted as compressions and expansions of the media through which they pass. The polarity of a wave refers to the direction of its first motion which depends upon the relative velocities of adjacent media through which the wave passes.

A low velocity, gas bearing horizon can sometimes be distinguished from a dense limestone by the opposite polarization of the reflected signals.[114] A final indicator of the possible presence of hydrocarbons is a reflecting interface that is perfectly horizontal. Since geological formations almost always have at least a regional dip, a horizontal interface is taken as evidence of a contact between two fluids such as gas over water or gas over oil. Where rock layers are flat, however, the fluid interface can not be detected.[115]

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[114] Hammond, Allen L. "Bright Spot: Better Seismological Indicators of Gas and Oil." Science, v. 185, August 9, 1974, p. 513.
[115] Ibid.

The bright spot technique is not applicable in all prospecting areas. It appears to work best in young, relatively uncompacted sediments in offshore basins, such as Tertiary age strata consisting of sands and shales. The technique is more difficult to apply in sedimentary beds on the continents where the geology often is more complex. It is also rather ineffective below 3,000 meters because the acoustic signals become too attenuated in passing through such thicknesses of rock. The bright spot is essentially a technique for finding gas rather than oil, since the density of oil is rather close to that of formation water, but wells drilled to tap suspected gas deposits will often produce both.[116] The bright spot anomaly can generally tell the geophysicist only that hydrocarbons are present. It can not always reveal the quality, the thickness of the pay zone, the kind of hydrocarbon, or the saturation of interval. One of the significant failures of the bright spot technique was on the Destin Dome in the Gulf of Mexico where the method reportedly indicated sizable relatively shallow gas deposits over a wide area and was probably responsible for the very high bidding for several tracts. A succession of dry holes drilled to date in the area indicates that the hydrocarbon potential was significantly over-rated.[117]

Shallow high resolution seismic data are used by the Geological Survey in lease management, for approving or rejecting plans of exploration or permits to drill; in lease evaluation; in environmental impact assessment; and in pollution prevention. Surface and shallow subsurface geologic hazards, when properly identified, seldom exclude minimal risk exploration and development programs.[118] High resolution surveys are used to detect faults, shallow gas accumulations, and gas seeps.

Water depth at any location is measured by bouncing a sound signal off the sea floor and recording the time it takes for the signal to make the round trip. If two seconds are required the water is about 1,440 meters deep, if one second is required the water is only 720 meters deep and so on for fractions of seconds. To obtain information on the thickness of sea floor mud, a stronger echo sounder, sometimes called a mud penetrator, is used. As the ship travels, this sounder bounces sound waves off rocks that commonly underlie the mud on the sea floor. The return signal is graphically recorded on a roll of paper. In this manner, a continuous record of the thickness of the bottom mud along the ship's path can be made.

Often, a magnetic sensor, called a magnetometer, is towed behind the survey ship. The sensor detects small warps or anomalies in the Earth's magnetic field which are produced by the different types of rocks that the ship passes over. These anomalies are indicators of the structure of the rocks at depth below the ocean floor.

Survey ships also often contain gravimeters, extremely sensitive instruments which measure slight changes in the force of gravity caused by the ship passing over rocks of varying densities. A diagram showing the various geophysical tools used by a survey ship in search of OCS hydrocarbons is shown in Figure 10.

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[116] Ibid.
[117] Prengle, Pixie. "Destin Dome or Anticlimatic Anticlime?" World Oil, April, 1975.
[118] Adams, M. V., et. al., op. cit., p. 14.

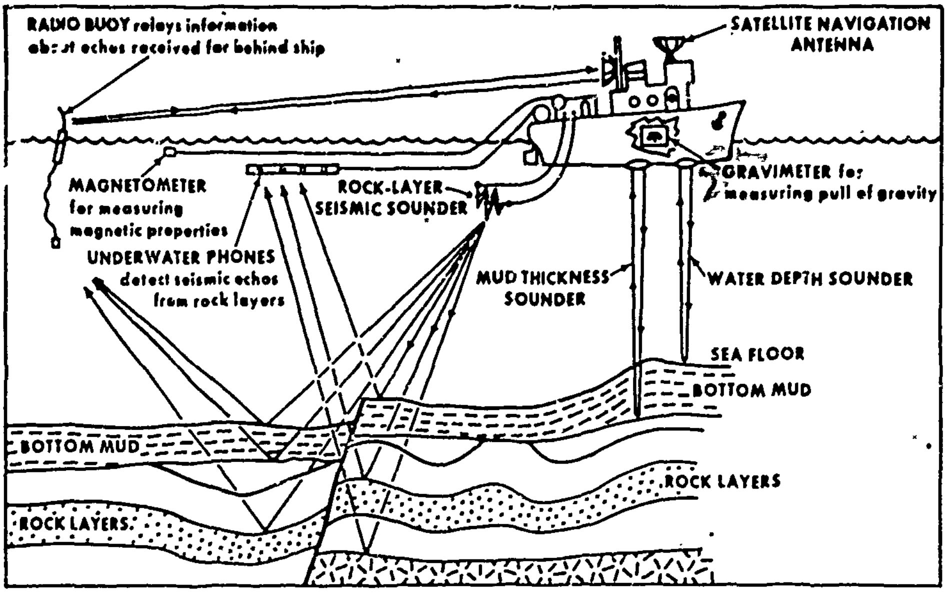

FIGURE 10

Source : U.S. Department of the Interior/Geologic Survey.

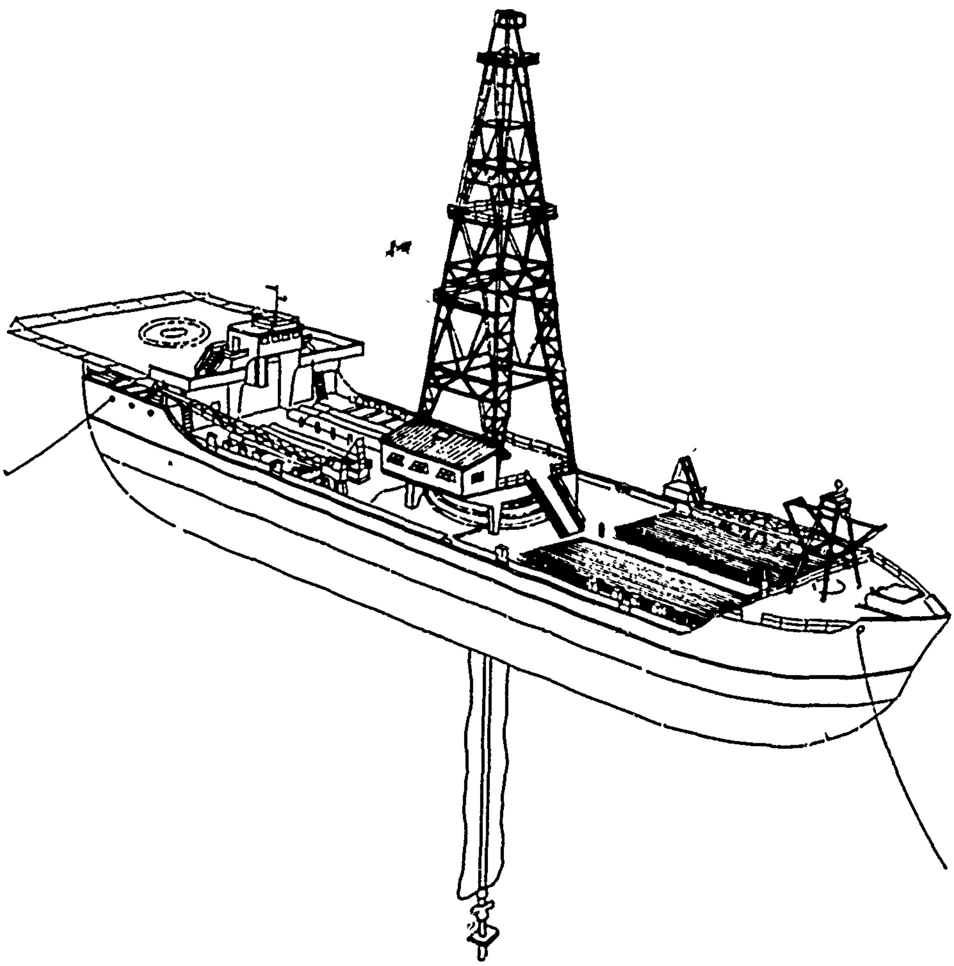

Diagram of a Drilling Ship

Courtesy Exxon Corporation.

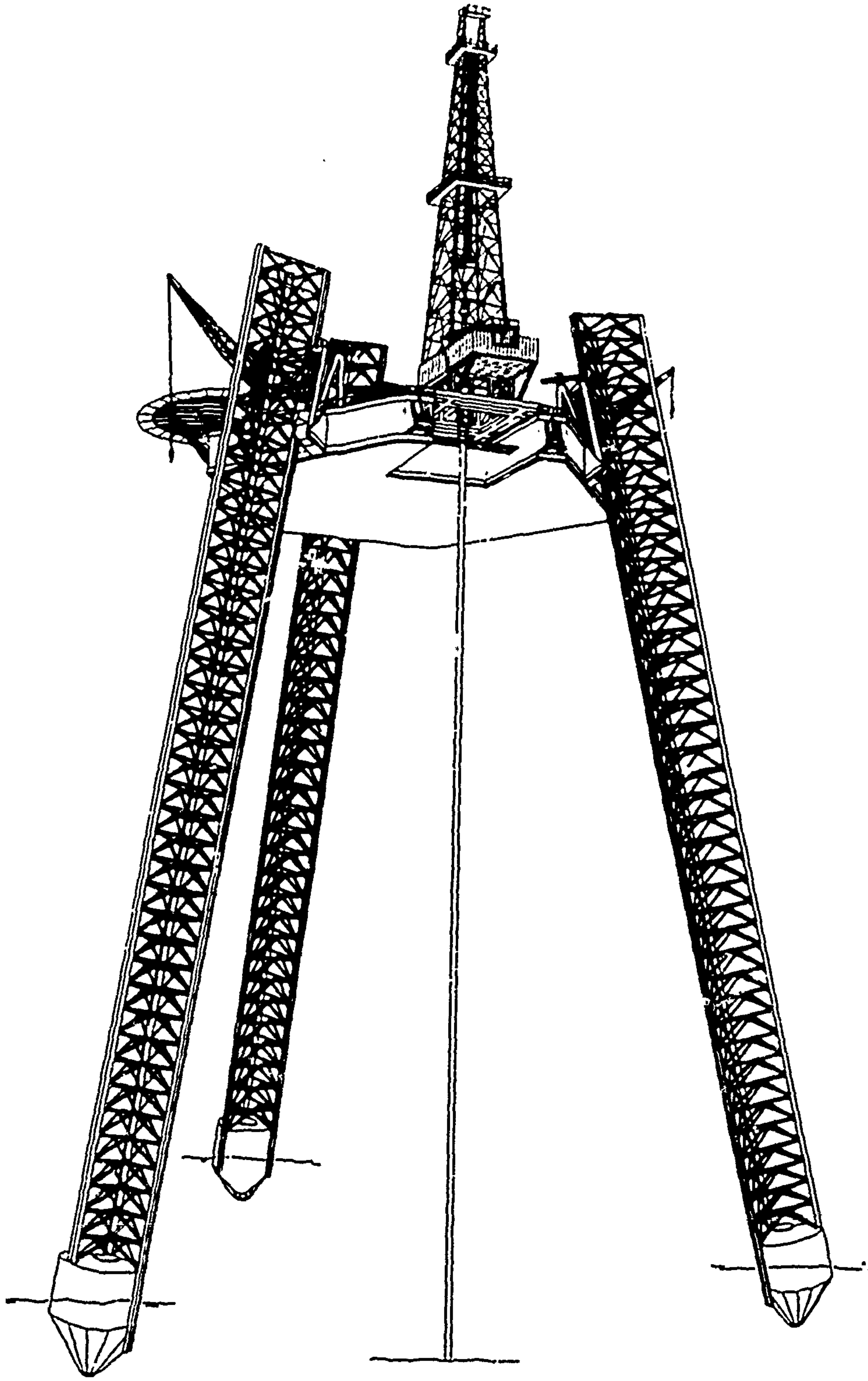

Diagram of a Jack-up rig

Courtesy Exxon Corporation.

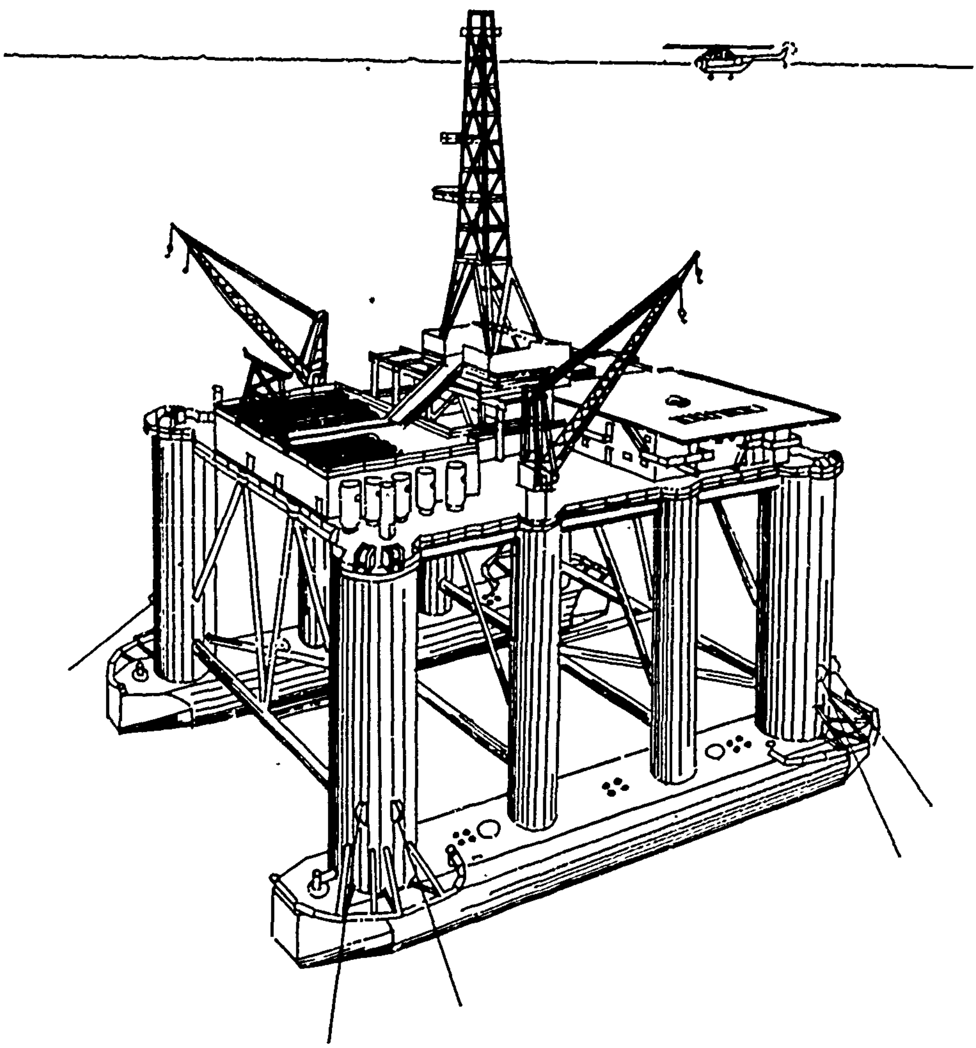

Diagram of a Semi-Submersible

Source: U.S. Department of the Interior/Geological Survey.

The geological and geophysical techniques used to explore the outer continental shelves for hydrocarbons are very useful as indicators of geological conditions (structures, lithology, etc.) conducive to the generation and entrapment of oil and gas and in locating potential prospects. The only sure exploration method, however, is to drill the prospect and test its fluid content. Without drilling, the oil and gas content of a given region cannot be determined with any certainty.

Exploratory Drilling and Rigs.—The drilling equipment used for offshore exploratory wells differs from that used onshore in several ways. Offshore drilling operations require a platform to support the drill rig and its associated equipment. There are four basic types of offshore exploratory drilling platforms now in use. These are barges, drill ships, jack-ups, and semisubmersibles.

Barges were used extensively in drilling the first wells in shallow waters in the Gulf of Mexico. Compartments in these early barges were controlled-flooded to set the barge on the seabed. This method of exploration drilling with submersibles was limited to water shallow enough (about 25 meters) to permit the upper structure of the barge to rise above the water to a height which would permit drilling operations to be conducted. In contrast, most new barges are floating. Although they are neither shaped like a ship nor self propelled, they are used much like drill ships and are suitable for drilling in water depths of 180 meters or more. This depth limitation is caused primarily by the anchor and chain systems used for maintaining position. Barges also have weather limitations since, because of their hull shapes, they have poor motion characteristics.[119]

Drill ships in general have the same lines as traditional merchant ships and are self-propelled and thus can move from one drilling location to another without assistance. Positioning is accomplished by a dynamic positioning system, a series of propellers or thrusters coupled to sensors which detect and compensate for movement, or a mooring system of chains and anchors. Drill ships have drilled and completed exploratory tests in water depths ranging to 650 meters off West Africa. The mix of drill ships and barges seems to be changing in favor of the drill ship. The *Glomar Challenger* proved that these vessels could operate successfully in the deep ocean and at great distances from land during several years of core drilling in water ranging to 6,000 meters. The three main advantages of the drill ship are: they are self-propelled and require no assistance to move into most locations; they require less horsepower for full dynamic positioning; and they have greater storage capacity, requiring less assistance from supply vessels.[120]

The big *Sedco 445* drill ship, commanding a day rate in excess of $30,000, drilled the West African wildcat in water about 650 meters deep and has maintained station in weather conditions as severe as 65 knot winds, 39 foot seas, and four knot currents. The computer controlled ship stays moored on station with power from 11 thrusters along with two main propulsion screws. The thrusters are 800 horsepower each and the screws are each 4,500 horsepower. The work done at 650 meters water depth has indicated, according to Sedco, that industry can move ahead with confidence that exploratory drilling can be conducted in water 600 to 1,800 meters deep.[121]

As drilling operations move into deeper water and more hostile environments, costs are expected to sharply increase. It has been estimated that future operating costs, including rig, supplies, and services, for drilling in 90 to 300 meters of water will be about $55,000 per day. Daily operating costs are expected to climb to $60,000 for 600 meters of water and to beyond $70,000 for 900 meters of water.[122]

Groups led by Shell and Amoco Production Co. expect to be drilling in 270 to 345 meters of water off eastern Louisiana the latter part of 1975. This would break the past Gulf water depth drilling record of some 205 meters. The deepwater record for drilling in the United States OCS is Exxon's 450 meter (1,497 foot) well in the Santa Bar-

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[119] Kash, Don E., et. al. "Energy Under the Oceans. University of Oklahoma Press, Norman, 1973, p. 37.

[120] "Drill Ships and Barges." Ocean Industry. v. 9. n. 9. September 1974. p. 66.

[121] "Big Drill Ship Paves Way for Drilling in 6,000 Feet of Water." The Oil and Gas Journal. April 7, 1975. p. 41.

[122] "Oilmen Tackle Technology, High Cost of Deep Waters." The Oil and Gas Journal. April 7, 1975, p. 40–41.

bara Channel. About 275,000 acres are under lease in U.S. waters deeper than 200 meters and additional deepwater acreage is scheduled in future sales.[123]

There are 71 drillships and barges in operation throughout the world with 30 additional units under construction. The approximate average cost of a new moored unit is $30 million and of a new dynamically stationed unit is $50 million.[124]

Jack-up rigs are drilling platforms with legs that can be moved up and down. When the legs are extended the platform can elevate itself above the ocean surface and temporarily become a bottom standing platform. By retracting its legs, the jack-up becomes a floater and can be moved from one location to another with assistance. Jack-ups can now drill in water depths up to about 110 meters. It is the most popular of the OCS drilling units, about 45 percent of the offshore rigs in operation are jack-ups. Its advantages include the fact that, within its water depth range, the effect of heavy seas is negligible.[125] Its water depth range, of course, is limited, but there remain vast shallow water areas yet to be explored. Also, its steel and engine requirements are considerably less than those of the other types of offshore rigs and thus its cost is relatively low. The estimated average cost of jack-up units now being ordered is $27 million.[126] The primary disadvantages of the jack-up are the difficulty of moving into location and the fact that many of the units cannot jack-up when long period swells are running. Another disadvantage is an awkward configuration during transit, the heavy steel legs, when projections upward, sometimes can cause a degree of instability. These problems, however, while troublesome, are not insurmountable and jack-ups have excellent operating records.[127]

There are 135 jack-up units in operation world wide with 57 new jack-ups under construction.[128]

A new innovation in jack-up design is Bethlehem Steel Corporation's new unit with telescoping legs which is designed for water up to about 115 meters deep. The unit is being constructed for operation in the Gulf of Mexico. The telescoping legs are the major feature of the new design and there is also a mat which rests on the bottom during drilling. The lower legs are attached to the mat and telescope inside the upper legs which extend through the hull and the jacking mechanism. In moving the unit from location, the platform's buoyancy is used to lift the mat off the bottom.[129]

Smaller jack-up rigs are also being planned. ETA Engineers, Inc. has announced a new compact relatively inexpensive jack-up, called the Beaver series, designed to drill to depths of 6,000 meters while standing in 54 meters of water. The shift to smaller jack-ups is an economic move in that offshore rig costs during the past five years have increased almost five-fold. For this reason, some contracts for the giant rigs have been canceled. The beaver is a drilling rig, but its modular equipment set-up permits easy removal of heavy drilling

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[123] Ibid.
[124] "Drillships and Barges." Ocean Industry, September 1975, p. 42.
[125] Jack-ups. Ocean Industry, September 1974, p. 76.
[126] Jack-ups. Ocean Industry, September 1975, p. 70.
[127] Jack-ups. Ocean Industry, September 1974, p. 76.
[128] Jack-ups. Ocean Industry, September 1975, p. 70.
[129] Ibid., p. 70–71.

equipment and the insertion of workover equipment or even production equipment. At the present time a number of jack-ups in the Gulf of Mexico are working below their capacities. The Beaver class rigs, with an estimated construction cost of from $10 to $15 million could be drilling in the shallow waters where the giants are being under utilized. Theoretically, with its lower construction costs, the Beaver could have a day-rate far below that of conventional jack-ups built at costs about double the Beaver.[130] Other rig designers and builders are also working on plans for compact jack-ups for the same economic reasons.

The semi-submersible is the newest type of offshore drilling rig available and is the best suited for severe weather conditions. These rigs have a platform deck supported by columns which are connected to large underwater displacement hulls or large vertical caissons or a combination of both. The columns, displacement hulls, or caissons are flooded on site to reduce the force of the waves by locating the major buoyancy members below the sea surface or below the level of wave action. The units are considered virtually transparent to waves of normal period as the water plane area of the columns usually is less than a third that of a comparable drillship. Semi-submersibles may or may not be self-propelled and they share the positioning limitations of all floating drill rigs. Most are presently positioned with mooring systems, but some are also equipped with dynamic positioning systems. The large semi-submersible was designed primarily for rough waters as are found in the North Sea and the Gulf of Alaska. Because of the projected exploration programs in such areas, the industry began a large semi-submersible construction program. However, in the last two years the governments of the United States, the United Kingdom, and Norway have adopted policies which have tended to reduce the demand for such units and as a result the projected construction expansion has somewhat diminished.[131]

There are 75 semi-submersibles in operation and 52 under construction. The estimated average cost of such rigs under construction is $45 million.[132]

A primary disadvantage of the semi-submersible is its high cost. For this reason a number of companies have produced designs for smaller units including a mini-semi. However, another major trend is the design and construction of big semi-submersibles for deep water operations, most of which will be self-propelled and dynamically positioned. Several large semi-submersible rigs have been designed for 900 to 1,200 meter depths.

Forex Neptune has designed such a unit to operate in water depths of as much as 1,200 meters. The semi-submersible will have four aft propellers (16,000 horsepower), four 2,000 horsepower steerable thrusters, and two 1,500 horsepower bow thrusters. Dynamic stationing will be achieved by orienting the unit toward the dominant wind and

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[130] "Mini-Rigs: Are They the Answer to Spiralling Cost of Drilling?" The Oil Daily, June 24, 1975.
[131] "Semi-Submersibles." Ocean Industry, September, 1975, p. 134.
[132] Ibid.

current, the main function of the thrusters being to withstand transverse winds and currents. The unit is designed with ship shaped lower hulls to be able to average ten knots with fuel consumption of less than 40 percent of that of a drillship cruising at 13 knots.[133]

According to the Department of Commerce, about one-third of the offshore rigs under construction are being built in the United States.[134]

Drilling methods and much of the equipment used offshore is similar to that used onshore. The hole is made by rotating a drill bit on the end of a string of drill pipe. Cuttings are removed from the bottom of the hole by drilling mud which is circulated down the drill string, out through the bit, and back to the surface via the annular space between the drill string and the bore hole and the marine riser. Marine risers have been developed to conduct the drill string from floating rigs to the hole being drilled and are designed to permit some lateral and vertical movements during the drilling operations without breaking off the drill string. In addition to removing the cuttings, the drilling mud helps to prevent blowouts by counter-balancing formation pressures and thus preventing the flow of liquids or gases to the surface from the reservoirs penetrated as the hole is drilled. The necessary balance is accomplished by regulating the weight of the mud being used and by controlling the mud flow rate. Other safeguards installed to assist in preventing blowouts are casing and blowout preventers. Casing is relatively large diameter steel pipe which is set and cemented into the hole and acts as a liner. The surface casing also provides an attachment for the blowout preventer stack which consists of a series of control valves which are capable of either closing around the drill string to seal off the annular space or closing off the hole completely. On land and on bottom-standing platforms offshore, the blow out preventer stack is attached to the top of the surface casing just beneath the rotary table on the rig floor. In the case of floating rigs, the stack is attached to the top of the surface casing on the sea floor and is hydraulically activated and controlled from the rig. Blowout preventers are activated manually and not automatically.

PRODUCTION AND DEVELOPMENT TECHNIQUES

If commercial accumulations of oil or gas have been discovered and defined during the exploratory phase of OCS operations, the development phase begins. Actually exploratory and developmental activities overlap. While exploratory wells are being drilled to determine the extent of the field and its recoverable reserves, some of the early exploratory wells may be in the process of being completed as production units as the production platforms are put into place. Extensive planning must precede development activities. A major step is the selection of a production facility. At the present time, the alternatives are fixed platforms, gravity platforms, subsea systems, and several proposed intermediate alternatives including buoyant towers and tension leg platforms.

[133] Ibid. p. 135.
[134] "U.S. Gets a Third of Offshore-Rig Orders." The Oil and Gas Journal, May 26, 1975, p. 48.

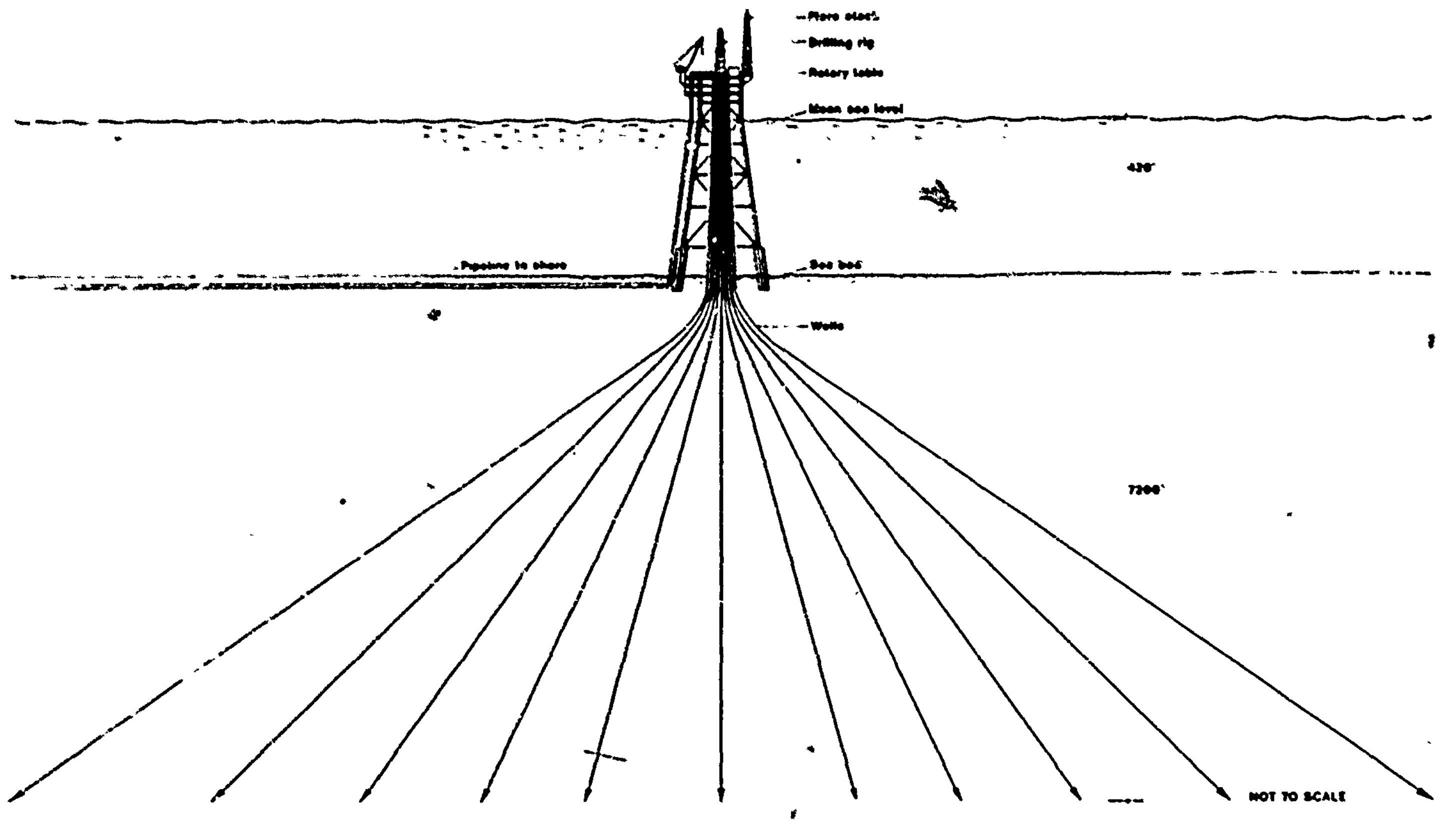

Diagram of the system of directional drilling which will be used in the development of the Forties oilfield in the North Sea.
Courtesy British Petroleum Company.

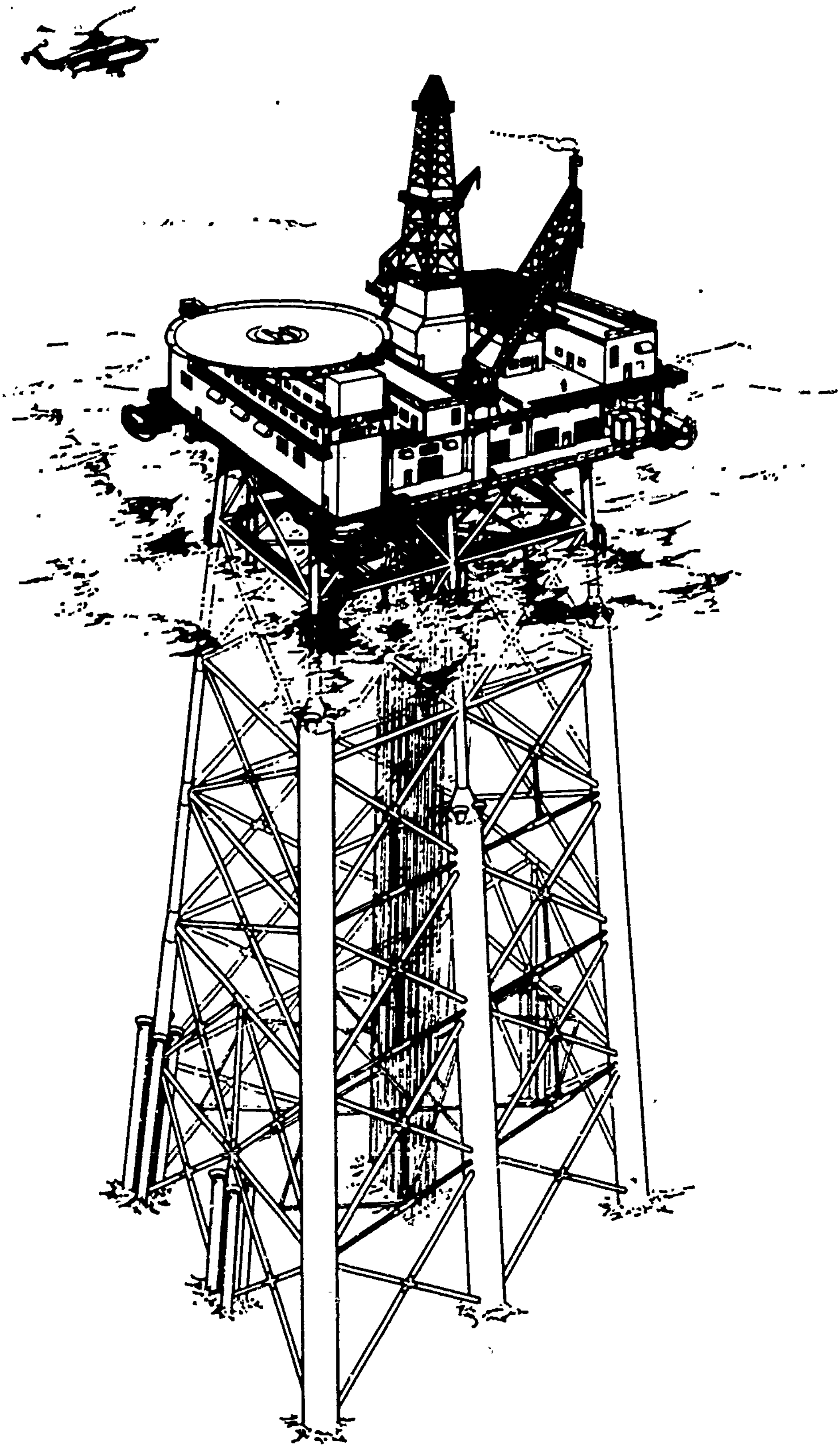

Diagram of steel production platform

Courtesy Exxon Corporation.

Fixed Platforms.—Fixed platforms have evolved from the simple wooden structures used by industry in the bayous of Louisiana in earlier days. Steel truss production structures are fairly standard within the oil industry. The platform is permanently attached to the sea floor by steel pilings and supports one or more decks on which drilling and production equipment is mounted. For both drilling and production, a large amount of equipment has to be mounted on a very compact platform, often causing complications.

Fixed platforms have been constructed for increasingly greater depths. Shell Oil Company is currently working on plans for two structures in 300 meters of water off Louisiana. Shell's Cognac platform would stand about 365 meters from seabed to derrick crown and would have eight legs and 16 piles. It would handle two rigs and have slots for 56 wells. If present drilling encounters sufficient reserves, the big platform would be installed during the summers of 1977 and 1978. This platform would be nearly three times as tall as the Gulf of Mexico's current deep water champion, Tenneco's Platform A which stands in 115 meters of water.[135]

In the Santa Barbara Channel, Exxon has developed plans for a giant platform which would total about 280 meters high and contain 28 wells. It would be placed in 255 meters of water.[136]

The limiting water depth of conventional fixed platforms has been estimated to be in excess of 300 meters. The two major technological problems are foundations and dynamic response, but the ultimate upper limit may prove in the end to be determined by economics.[137]

In the Gulf of Mexico, a total of 804 production platforms have been installed, 647 of which are still on active leases. Of the total 804 platforms, 134 have been salvaged for reasons including depleted fields and physical wear and tear. Hurricanes have claimed 17 platforms, a relatively small number considering the number of such storms in the Gulf since 1947. Six of the 804 platforms were lost to either fires, blowouts, or other unusual causes.[138]

The tension leg platform is designed for use in deeper waters where conventional bottom supported platforms become increasingly expensive. It is similar to a taut-moored buoy, being a buoyant structure held beneath the surface by tension members. The buoyant structure, in turn, supports a working platform held above the water surface by means of vertical columns which themselves are buoyant. This type of platform is being designed to carry out many of the activities necessary for offshore oil operations such as exploratory drilling, development drilling, supporting production equipment, and workover

[135] "Oil Men Tackle Technology, High Cost of Deep Waters," op. cit., p. 42.

[136] "Interior OKs Santa Ynez Production." The Oil and Gas Journal, August 26, 1974, p. 52.

[137] Kash, Don E., et. al., op. cit., p. 52.

[138] Carmichael, Jim. "Industry Has Built Over 800 Platforms in the Gulf of Mexico." Offshore, May 1975, pp. 230–231.

operations on subsea wells. A prototype tension leg platform developed by Deep Oil Technology Inc. has recently been tested off California.[139]

The tension leg platform is anchored directly beneath its columns. The anchors are either drilled-in pilings or deadweight clumps. The tension members, which are large cables, connect the anchors to the platform columns and remain under tension at all times. The platform does not move up and down and the distance between the platform deck and the seafloor remains virtually unchanged. The primary advantage of the tension leg platform over the conventional platform is that in deep water it requires less steel and thus cost less. Another important feature of the tension leg platform is its mobility, it can be relocated with comparative ease. It has a final advantage in its flexibility with regard to depth and location. It need not be designed and built for a specific location or water depth and with modification can be made suitable for about any location within a general region, allowing construction to begin on a platform prior to defining its exact location.[140]

The Aker Group and Saga Petroleum A/S & Company have jointly developed a floating platform called the Aker TPP (tethered production platform). It uses 12 tension leg cables to hold the floating steel platform in place. The wells are completed on the sea floor in a subsea module connected by risers to the platform. The system is designed to operate in water depths of 150 meters, but increased depths add little to the cost of the unit because of the tension leg system which is tethered to piles driven into the seabed. The platform will be fully equipped with process and drilling equipment and arrive on site ready to operate. During model tank tests the platform performed well in 100 foot waves.[141]

Chicago Bridge and Iron Company has conducted a research study for Exxon Production Research Company that show that a buoyant drilling tower can be installed in waters up to 450 meters deep. The tower would contain buoyancy chambers and ballast tanks and would be attached to a seabed base with a giant U-joint. Construction of a single buoyant platform with a capacity of 40 wells would cost an estimated $44 to $58 million. The buoyant tower differs from a conventional structure in that a universal joint near the ocean floor would permit the tower to tilt and oscillate when subjected to wind, current, and waves. The force required to prevent the tower from tilting excessively is provided by its buoyancy near the ocean surface.[142]

[139] Horton, Ed, "Tension Leg Platform Prototype Completes Pacific Coast Test." Ocean Industry, September 1975, p. 244.
[140] Ibid.
[141] "Aker Unveils Tension-Type D&P Platform." The Oil and Gas Journal. October 6, 1975, p. 37.
[142] Kennedy, John L. "Buoyant Tower Would Allow Deepwater Platform Drilling." The Oil and Gas Journal, October 28, 1974, p. 61.

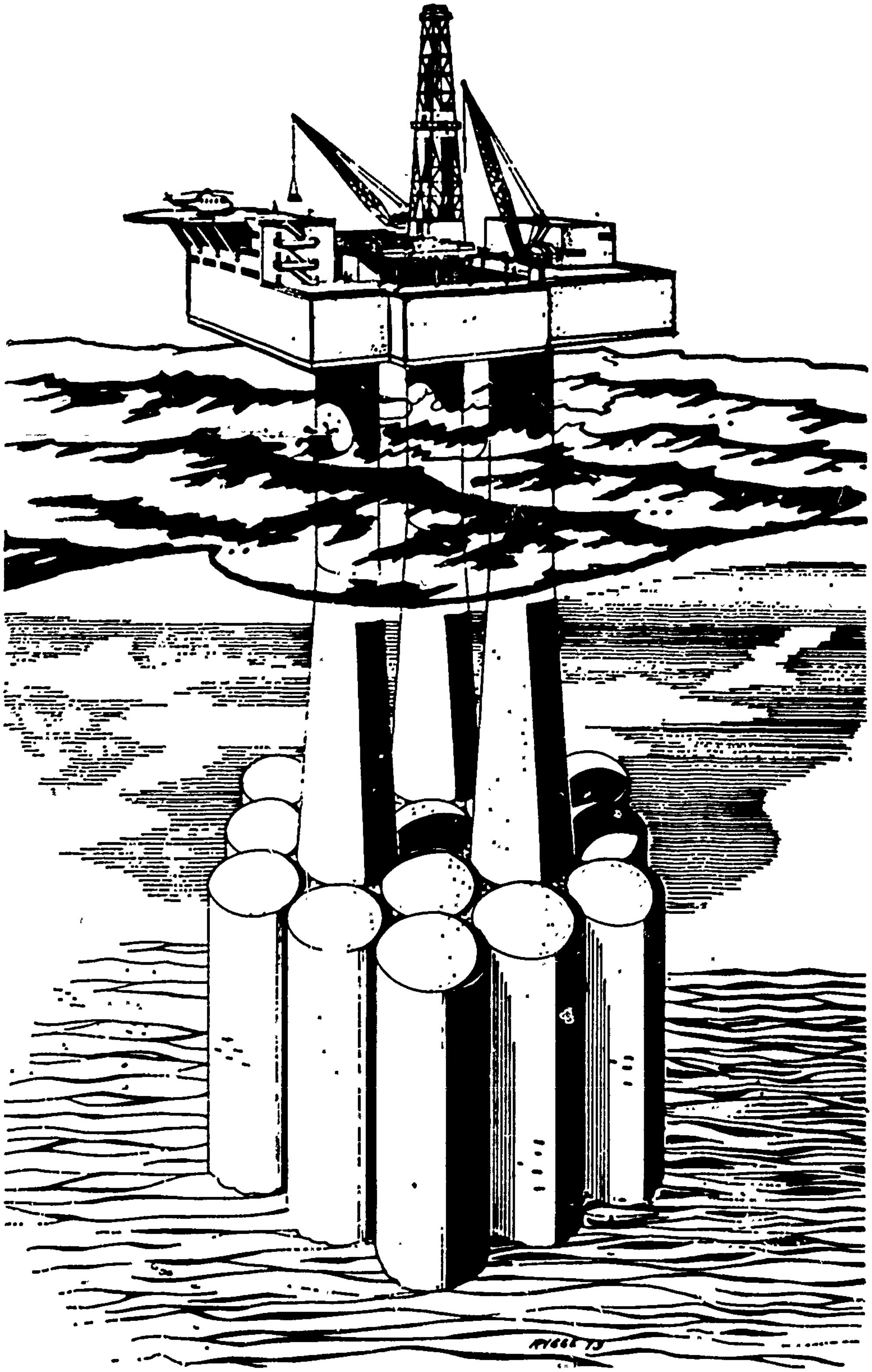

Diagram of Gravity Platform

Courtesy Exxon Corporation.

A new guyed tower platform has been designed for waters up to 600 meters by Exxon Production Research Company. Exxon has invited other organizations to participate in a scale model test of the new structure in the Gulf of Mexico. Exxon feels that the guyed tower is more simple and potentially less expensive than the buoyant tower, and could be perhaps as much as 40 to 50 percent less costly than conventional structures in deep water.[143] A large part of savings would be in reduced steel requirements and another component of the potential cost savings would be in construction expenses. The guyed tower is a trussed structure that rests on the ocean floor without pilings and is held in place by guylines. A design for the North Sea calls for the tower to support 24 wells. The tower would sway between one and two degrees during the passage of large waves, so the well conductors must flex at the tower base. The tower deck is designed to support a fully integrated drilling and producing system on two levels. The tower base consists of a truss-reinforced stiffened shell called a spud can which, after the tower is uprighted, is forced into the seafloor by the weight of heavy drilling mud until the desired load carrying capability is reached. The tower designed for North Sea conditions would be held up by 20 three and one-half inch bridge strands of steel cable arranged symmetrically around the structure and attached to clump weights on the ocean floor. The weights are designed to be lifted off the bottom only by large storm waves, thus softening the mooring system and allowing the tower to displace more with the wave. Beyond the clump weights, each guyline runs either to an anchor pile or to a conventional drag anchor. If a line should fail, the structure will not be in danger of collapse as the guying system is designed to be highly redundant.[144]

Gravity Platforms.—The use of gravity, or pileless, platforms is one means of installing huge offshore structures in deep water under difficult weather and sea bottom conditions. There are a variety of gravity platform designs, but most of those under construction are made primarily of concrete. Concrete is preferred at present for the North Sea, where most of the gravity platforms now under construction will go. There are, however, steel gravity structures also being built. These will be placed offshore of the Congo where a hard sea bottom has also caused designers to rule against structures requiring piles.

As their name implies, gravity platforms rest on the sea floor, stablized by their own weight without deep pilings. The principal technical requirement for the stability of such platforms is the prevention of foundation failure. Conceivable modes of foundation failure include: sliding between the base of the gravity structure and the soil; bearing capacity failure; progressive failure caused by softening along the rim of the base; and liquefaction of the soil.[145]

On June 30, 1973, a mammoth concrete oil storage tank was safely installed on the sea bottom in Norway's Ekofisk oil field in the North Sea. It has performed satisfactorily and its construction and installa-

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143 McNabb, Dan. "Guyed-Tower Platform Design Nearing Offshore Test in Gulf of Mexico." The Oil and Gas Journal, July 14, 1975, p. 86.

144 Ibid. p. 88.

145 Foss, Ivar. "Concrete Gravity Structures for the North Sea." Ocean Industry, August 1974, p. 58.

tion have helped test several aspects of concrete gravity structure fabrication. Concrete is a suitable material for a number of reasons including ease of construction and resistance to corrosion and fire. One reason for the popularity of the concrete design in the North Sea is that, unlike the Gulf of Mexico where deep deposits of soft clay predominate; marine soil conditions at most of the major fields in the North Sea consist of stiff clays and dense sands which are able to support the heavy loads introduced by the concrete platforms.

At least eight concrete gravity platforms are now under construction for North Sea fields and two are on order. Six are being built in Norway and two in England. Chevron Overseas Petroleum has reported that a new 550,000 ton concrete platform that will be completed for the Ninian field in the North Sea will cost about $500 million.[146] In addition to the concrete structures being built for the North Sea, four steel gravity structures are under construction in France for installation offshore of the Congo.[147]

A difficulty associated with gravity platforms is the scarcity of coastal sites in which they can be built. Unlike conventional designs, gravity platforms are constructed in an upright position and completed largely on shore before being towed vertically to their destination at sea. The platform fabrication site must have very deep water and a clear path out to sea with a depth of as much as 180 meters. Few coastal sites meet these requirements. Conventional platforms, by contrast, are usually completed at sea. The concrete gravity platforms now under construction in Norway and in England will stand in water depths ranging from 100 to 150 meters.

The steel gravity platforms under construction in France will be installed in 90 meters of water in the Loango field off the Congo. The sea bed there is formed of hard organic limestone which caused flat steel footings to be selected for bottom support. The hard rock also led to discarding the idea of piled platforms due to the long time and high cost required for pile installation.

A new type of concrete platform has been designed by Caledonian Platform Structures Ltd. which is claimed suitable for installation in soft seabed areas. Concrete platforms have previously been considered unsuitable for soft areas, but this design incorporates a wide spread base to minimize settling and a ballasting technique to compensate for any settling that does occur. The design is for all North Sea conditions and for waters up to 150 meters deep.[148]

Conditions must be carefully analyzed before the installation of a gravity platform. There is a lack of experience with concrete gravity structures regarding scour behavior and strength retention. The exact sea bottom where the platform is to be set is critical as any last minute change in location can affect the entire design of the structure. It is also difficult to position a large structure exactly in the spot where the soil samples were taken.

[146] "Staggering Cost Figures Continue To Surface in the North Sea's Operations." The Oil and Gas Journal Newsletter, October 13, 1975.

[147] Kennedy, John L. "New Types of Gravity Structures Near Completion." The Oil and Gas Journal. May 5, 1975, p. 210–212.

[148] "New Concrete Platform Design Unveiled for Soft-Seabed Areas." The Oil and Gas Journal, June 16, 1975, p. 37.

It appears possible, however, that a combination of the advantages of both conventional steel structures and gravity type platforms might be achieved in a single structure. Short piles to provide added stability to a gravity platform might make the most of both approaches.[149]

Subsea Systems.—Subsea completions involve placing wellheads on the ocean floor rather than on production platforms. The produced oil or gas is transferred from the subsea wellhead either to a nearby platform or to a shore facility for processing. There are over 70 subsea completions in operation in offshore U.S. waters.[150]

Several subsea completion systems are available. The systems are used for fields which do not lend themselves to conventional platform development because of either limited hydrocarbon reserves or deep waters.

In general, however, it will probably be several years before subsea production technology will be available for use in complete deepwater systems. Total subsea development investment and operating costs are expected to be considerably higher than those for conventional platform development. The higher costs result primarily from the requirement to drill all development wells with mobil rigs and from higher equipment costs. Some oil companies believe, however, that subsea completions become economical when compared to platform completions in water depths greater than about 300 meters.[151]

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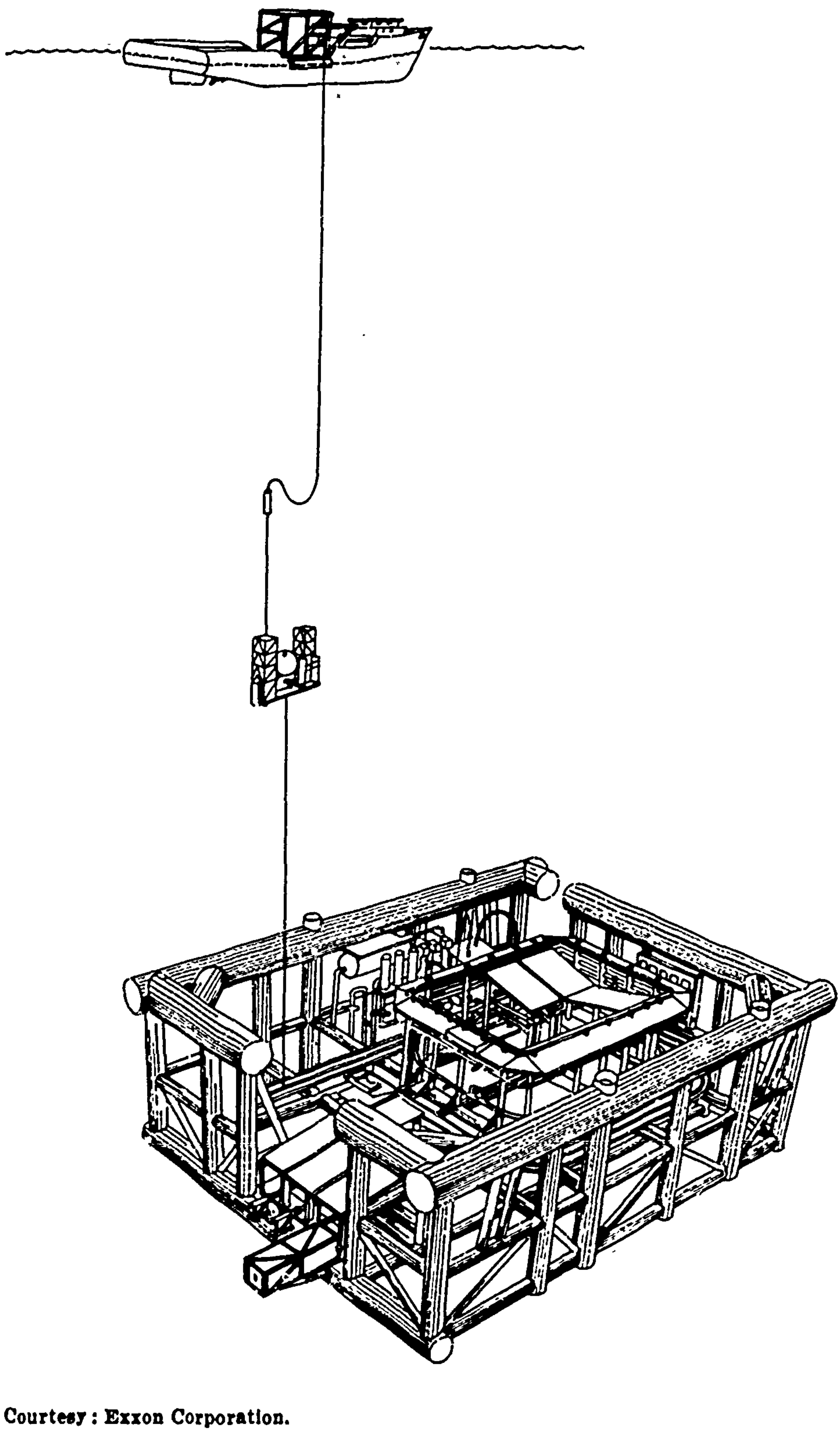
[149] Kennedy, John L., op. cit., p. 220.
[150] Kash, Don E. et. al., op. cit., p. 52.
[151] "Oilmen Tackle Technology and High Cost of Deep Waters," op. cit., p. 43.

Subsea Production system



Courtesy : Exxon Corporation.

One obstacle to development of sebsea systems is the depth at which a flow line can be connected to the subsea well equipment. The deepest water in which a flow line has been connected to a subsea well is about 115 meters and all connections except one have been made with diver assistance.[152] Remote systems are being designed for use in water depths below 300 meters, but are not expected to be operational until the 1980's. Diving capabilities, needed in emergency backup systems in the event of equipment failure, are expected to be extended to 480 meters within the next five to ten years. The deepest open sea working dive to date is about 255 meters, but 90 meters is considered to be about the normal limit of conventional diving.[153]

No two subsea completions are alike, each producer has unique problems which must be solved with unique approaches. Thus, the systems come in a variety of configurations. They include both wet systems, in which the well head equipment is exposed to the water, and dry systems which contain essentially conventional wellhead equipment within watertight chambers at atmospheric pressure permitting men to perform maintenance activities in a shirtsleeve environment.

The Lockheed Petroleum Service's Subsea System places both men and hardware on the sea floor where standard oil field techniques are used to complete each subsea well. The wells are then linked to subsea manifolding and production unit facilities. Each wellhead and each manifolding and production unit is enclosed in an individual man-rated pressure chamber. Within these chambers, men using regular oil field tools and techniques assemble control valves, piping, and production equipment. The flowlines are drawn into ports in each chamber wall using a dry pull-in technique. The service capsule is equipped with life support systems, communications, and electric power by an umbilical linking to the surface support vessel. The present system has a water depth capability of 360 meters, but future systems are expected to be able to operate at several times that depth. The complete system consists of wellhead cellars, which are placed on individual wells; the manifold center, which brings together and can monitor the oil and gas from producing zones; and the separation and pumping station from which oil and gas can be pumped ashore or to the surface. Lockheed is now taking orders for single wells and expects to have the complete system which can operate without a platform on a multiple well unit available before 1980.[154]

Shell and Lockheed installed the first dry wellhead cellar on a commercial oil well in 1972. The completion is in 113 meters of water off Louisiana. Shell plans to install two more subsea wellhead chambers and a manifold center this summer. Lockheed's second generation horizontal chambers are going to be used.[155]

Shell has completed several other subsea wells. The company completed five gas wells in about 75 meters of water in the Santa Barbara Channel between 1963 and 1965. The gas reserves in the field did not justify installation of a platform so the five wet system completions were considered to be the most economical solution.[156]

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[152] "U.S. Operators See Delay for Subsea Systems." The Oil and Gas Journal, April 21, 1975, p. 42.

[153] Ibid.

[154] "Outer Continental Shelf Oil and Gas Development and the Coastal Zone." Report for the National Ocean Policy Study, Senate Committee on Commerce, U.S. Government Printing Office, Washington, D.C. November 1974, p. 87.

[155] "Oilmen Tackle Technology and High Cost of Deep Wates," op. cit., p. 43.

[156] Ibid.

Subsea Equipment Associates, Ltd. (SEAL) has completed a successful two year testing program of its multiple well atmosphere production system in 75 meters of water in the Gulf of Mexico. The system houses conventional correcting, testing, and metering equipment for oil and gas production in a nitrogen atmosphere to prevent fires and explosions. The multiple well system can combine and control oil and gas production from as many as 18 wells, which are drilled from a surface rig. The system is installed on the sea floor without the use of divers. A base is towed to the site and submerged carrying down the subsea equipment enclosure. The enclosure has a control section for electrical equipment and a lower portion for oil handling equipment. Wellhead connectors are lowered from the ocean surface by the use of guidelines. The connectors link the wells drilled on the periphery of the enclosure to the oil control and handling equipment. The multiple well production system normally operates without manned intervention; however, service personnel can be lowered into the subsea enclosure with a transfer bell where they can work in a shirt sleeve environment on the ocean floor.

Another subsea production unit developed by SEAL is the single wellhead system which will be tested in 150 meters of water in the Mediterranean Sea. It is designed for single, high production wells in moderate to deep water and can be remotely installed and maintained without the use of divers. The system consists of three basic modules with the base and master valves remaining on the ocean floor. When servicing is required, a special re-entry and handling tool replaces the module in question with a reconditioned module. If man should ever have to intervene, a back-up work enclosure can be installed over the wellhead. Service personnel are lowered to the enclosure by means of a transfer chamber. The oil or gas produced by such subsea systems can be routed to a shore facility, a platform, or a surface tanker.

The SEAL multiple well production system was designed for operation in depths to 450 meters and the single well system was designed for operation in 360 meters of water. One advantage of the systems, according to SEAL, is added protection against the risk of pollution. The wellhead control equipment is located on the ocean floor and thus is freed from the vulnerability of damage by ships and storms. The systems have been designed to withstand earthquakes and to shut down automatically should anything go wrong. Fire hazards have been reduced as the oxygen atmosphere necessary to support combustion has been eliminated.[157]

Sometimes expensive platforms are spaced at distances which do not permit full recovery of oil from an offshore field. The SEAL systems have been designed to produce oil and gas from field areas not reached by platforms.

SEAL is also working in the North Sea. The company is installing a wet single well system in about 118 meters of water in the Beryl field.[158]

Exxon has installed its remotely controlled subsea system in the Gulf of Mexico in about 51 meters of water. Tests are now underway on this new submerged production system.

Transportation.—Oil and gas is transported from production wells

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[157] "Outer Continental Shelf Oil and Gas Development and the Coastal Zone," op. cit., p. 89.

[158] "Oilmen Tackle Technology and High Cost of Deep Waters," op. cit., p. 43.

on the outer continental shelf to the shore either by pipelines or by bulk carriers, such as tankers or barges. Currently all of the gas and almost all of the oil produced offshore of the United States is transported to shore by means of pipelines. Nearly all plans for new development of OCS petroleum resources also incorporate pipelining in one form or another. Nevertheless, barges and tankers are used as a temporary means of transportation during field development or to transport oil from low production fields. In bulk transportation operations, the principal risk of spilling oil occurs either during transfer operations or as the result of collisions. Since bulk carriers have a poor oil spill record in coastal waters, the alternative of substituting tanker or barge transportation for pipelines is not now attractive.[159] Also, tanker and barge transportation can be interrupted by bad weather which may necessitate shutting down production, thus interrupting the supply to onshore users. Offshore storage facilities can provide a buffer between the continuous production of wells and the discontinuous tanker operations. Since most of the oil produced on the OCS of the Unitel States is pipelined to shore, offshore storage has not been used to any great extent here. The major technological advances in offshore storage technology has been developed in response to needs in other parts of the world. Continental Oil Company's Dubai installation in the Persian Gulf consists of three tanks each with a capacity of 500,000 barrels and Phillip's Ekofisk concrete storage tank in the North Sea has a capacity of one million barrels.

Pipelines serve two major purposes on the OCS, gathering the gas or oil and transmitting them to land. Gathering lines move production to a central point for measuring, storage, or treatment. These lines terminate at the final metering point which is under U.S. Geological Survey jurisdiction. Pipelines which move oil and gas beyond this point are known as transmission lines.

There are three primary methods used to lay pipeline offshore. The most common is the lay barge or "stovepipe" technique in which sections of pipe, usually coated with concrete, are welded together on a lay barge and released into the water as the barge moves forward. Lay barges are used for pipe as small as four inches in diameter and as large as 52 inches in diameter.[160]

A second technique is the reel barge, in which long sections of pipe are welded on land and wound onto a large reel on the barge to be later laid directly from the reel into the sea. Currently this technique is limited to pipe of 12 inch diameter or less. For pipe diameters in the four to ten inch range, reel barges are often more economical than lay barges.[161]

A third method is to pull pipe from make up facilities onshore into the water; but because of the stress on the pipe owing to frictional drag, the pull method is limited to lengths of two to four miles (3.2 to 6.4 kilometers). A related technique is called float-and-sink in which a length of pipe is assembled onshore, given auxiliary buoyancy with strapped on tanks, floated to location, then sunk and connected to other sections with underwater welds. The use of this approach is sharply limited by the requirements for calm seas and by the high cost of associated diving operations.[162]

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[159] Kash, Don E., et. al., op. cit., p. 64.
[160] Ibid., p. 68.
[161] Ibid.
[162] Ibid.

Although it was once common to lay pipe directly on the sea floor, it is now more common to bury the pipeline to avoid damage from currents, storm waves, and anchors and other marine equipment. A burial barge is used to sink the pipe beneath the seabed surface, usually by displacing soil with a high-pressure jet.

Weather presents the greatest risk to pipelaying activities. In the Gulf of Mexico pipelaying barges work only about 220 days a year. Wave heights of six feet are often sufficient to shut down normal pipelaying operations, but newer semi-submersible equipment can apparently function in waves up to 16 feet.[163]

The future use of pipelines on the OCS is centered on the problem of limiting water depths. Conventional techniques for laying pipe of 12 inches in diameter or larger are limited to about 120 to 150 meters of water.[164] There are two basic problems associated with greater depths, diver and structural limitations. While working in deeper water, lay barges use an articulated structure with adjustable buoyancy, known as a stinger, to support the pipe between the barge and the ocean floor. Another approach for increased water depths capability is the use of an inclined or a vertical assembly area for the pipe which tends to reduce the overbend when the pipe is no longer supported by the stinger.

Methods of laying pipe in deep water may appear somewhat similar to those now in use for shallower areas, but increased loads and demands on construction equipment will require significant modification in the capabilities of the navigation and positioning systems and the tension equipment. These added requirements when added to the increased cost of thick-walled pipe will result in higher overall costs. The thick-walled pipe (perhaps greater than one inch) will be needed to withstand the combination loads of bending and the high external pressures of the deepwater environment. The loads are greatest during the construction period. The greatest wall thickness in an existing sea line is 0.875 inches in a gas line from the North Sea Ekofisk field to West Germany.

The industry is generally credited with having the capability of laying lines in 300 meters of water with wall thicknesses approaching one inch.[165]

The deepest pipeline in the world is in 355 meters of water between Sicily and Italy in the Strait of Messina. The ENI group installed 15 kilometers of experimental 10¾ inch concrete-sheathed line across the strait in the fall of 1974. The wall thickness of the pipe is ⅝ inch. The line is a preliminary step in a project to transport gas from Algeria to Italy. The ENI group plans to lay pipe 392 meters beneath the surface of the Mediterranean. To accomplish this task, a new semi-submersible lay barge designed to be able to lay pipe in water depths to 600 meters, is under construction. The total cost of the vessel and equipment is expected to be over $92.5 million.[166]

Brown and Root, Inc. also have ordered a giant pipelaying vessel which is scheduled for completion in 1976. It will be capable of laying 60 inch line in North Sea waters up to 300 meters. Other vessels for laying smaller line in deep water are also under construction.[167]

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[163] Ibid.
[164] Ibid. p. 69.
[165] "Oilmen Tackle Technology, High Cost of Deep Waters.," op. cit., p. 43.
[166] Ibid.
[167] Ibid.

CHAPTER II

OCS LEASING AND MANAGEMENT

I. THE CURRENT SYSTEM

A. Legal Authority

The mineral resources of the Outer Continental Shelf (OCS) come within the purview of the OCS Lands Act of 1953.[1] Pursuant to this statute the Secretary of the Department of the Interior is empowered to issue permits and lease tracts on the OCS to private interests who are then authorized to explore and extract the mineral resources found there. The Secretary may condition such authorization and can regulate activity associated with it. No mineral exploration or extraction may be carried out in the OCS adjacent to the United States beyond the 3-mile territorial limit without the necessary approval[2] from the Secretary. To better understand the purposes of and the reasons for the OCS Lands Act, it may be helpful to consider how the Act evolved.

On September 28, 1945, President Truman by executive proclamation,[3] declared that the United States has the exclusive control and jurisdiction over the natural resources of the seabed and subsoil of the Continental Shelf adjacent to the U.S. Although this unilateral action was not recognized internationally at that time, the doctrine was subsequently ratified by reason of the First Law of the Sea Conference held in Geneva in 1958. The conference resulted in the formulation of four conventions, one of which, the Convention on the Continental Shelf,[4] recognized in Article 2 that a coastal nation "exercises over the Continental Shelf sovereign rights for the purpose of exploring it and exploiting its natural resources."

During this period from 1945 until the formal international "recognition" of the Truman proclamation in 1958, the individual States and the Federal Government were involved in a dispute as to which had the paramount rights to the resources of the Continental Shelf. Several events emerged from this dispute which shaped the future control over this region.

The first of these was the United States Supreme Court decision in *U.S.* v. *State of California*,[5] where the Court ruled that the U.S. and not the State of California, had the paramount rights in and power over the three-mile belt (territorial sea) in the Pacific Ocean, including full dominion over the resources of the soil under the water, not the least of which, of course, is oil. Subsequent decisions of the

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[1] Pub. L. 212, 67 Stat. 462 (1953); 43 U.S.C. 1331–1343.

[2] Approval is either in the form of a permit to conduct geological and geophysical exploration or a lease to carry out exploratory drilling, development and production of mineral resources.

[3] Executive Proclamation No. 2667, 59 Stat. 884 (1945).

[4] 15 U.S.T. 471; TIAS 5578.

[5] 332 U.S. 19 (1947).

Court applied the same principle to the Gulf of Mexico (*U.S.* v. *Louisiana*,[6] and *U.S.* v. *Texas*[7]).

The second major event was the passage of the Submerged Lands Act of 1953.[8] This Act conveyed whatever rights the U.S. had in the lands underlying the three-mile belt in the Atlantic and Pacific Oceans, Gulf of Mexico, and Great Lakes to the respective States. This effectively changed the law as laid down in the *California*, *Louisiana* and *Texas* cases by the U.S. Supreme Court. It gave the States the title and ownership of the lands and natural resources seaward of their coasts three nautical miles (approximately 3.5 statute miles).[9]

The Submerged Lands Act was the culmination of effort, dating back to 1937, to establish State control of the submerged lands adjacent to their shores,[10] but the impetus that led to this realization in 1953 was undoubtedly the decisions of the U.S. Supreme Court. As pointed out in the Legislative History of the Act, the legislation came about because of the need to promote the recovery of petroleum resources, to end the confusion and controversy surrounding the litigation involving these areas, to bring an end to the delay in the recovery of the resources caused by the litigation, and to avoid prejudicing the U.S. position internationally in light of other nations' claims to jurisdiction seaward from their shores.[11]

The third event was the passage of the Outer Continental Shelf Lands Act of 1953. This Act had originally been title III to the bill (H.R. 4198) which later became the Submerged Lands Act, but the Republican leadership convinced the Senate that due to the complexities of the issues relating to the Outer Continental Shelf, Title III should be deleted from that bill. On the promise that an OCS bill would be brought before the Senate shortly, the bill passed without the OCS title and was signed into law by the President on May 22, 1953.[12] The OCS Lands Act subsequently passed on August 7, 1953.

The OCS Lands Act specified that the OCS could be leased and developed by the Federal Government. As pointed out in the Legislative History of the OCS Lands Act,[13] the Submerged Lands Act only established that the seabed and subsoil adjacent to the U.S., and beyond the State 3-mile belt, was subject to its jurisdiction and control.[14] It did not provide for the leasing or development of the area. Therefore, the OCS Lands Act was passed to accomplish that purpose. The Act authorizes and empowers the Secretary of the Interior to promulgate rules and regulations to assist in carrying out its provisions.

The OCS Lands Act does not stand alone in administering the OCS, however, and it must be read in conjunction with other laws which

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[6] 339 U.S. 699 (1950).

[7] 339 U.S. 707 (1950).

[8] Pub. L. 31, 67 Stat. 29 (1953); 43 U.S.C. 1301–1315.

[9] The Act left open how far seaward the boundaries of the Gulf Coast States could extend—but in no event more than three marine leagues (approximately 10.4 statute miles).

[10] Shalowitz, "Shore and Sea Boundaries," U.S. Dept. of Commerce, 1962, Vol. 1, p. 115.

[11] 1953 U.S. Code Congressional and Administrative News, p. 1386.

[12] Christopher, "The Outer Continental Shelf Lands Act: Key to a New Frontier," 6 Stanford L. Rev. 23, 30 (1953).

[13] 1953 U.S. Code Congressional and Administrative News, pp. 2177–2178.

[14] The issue of whether the Federal or State government had jurisdiction and control over the proprietary interests in the continental shelf beyond the 3-mile belt conveyed to the states by the Submerged Lands Act, was tested in *United States* v. *Maine, et al.*, 420 U.S. 515 (1975). The Supreme Court ruled that the Federal government and not the states had jurisdiction and control over this area of the continental shelf beyond 3 miles.

bear on its application. The most notable of these laws is the National Environmental Policy Act,[15] which requires that where there is major Federal action, an environmental impact statement (EIS) must be prepared. The EIS is prepared by the Department of the Interior prior to the sale of a lease for oil and gas exploration and development on the OCS.

Another law that in the future will have a significant bearing on the OCS Lands Act is the Coastal Zone Management Act of 1972,[16] which states in section 307(c) that Federal activities in or affecting the coastal zone must be carried out in "a manner which is, to the maximum extent practicable, consistent with approved State management programs" (i.e. section 306 programs). Although at the present time there are no approved management programs, if and when such programs are approved, OCS leasing and the resulting activity will need to be considered in light of the States' efforts to manage their coastal margins under their approved programs. The Marine Protection, Research, and Sanctuaries Act of 1972 [17] authorizes the designation of marine sanctuaries in ocean waters from the three-mile limit to the outer edge of the Continental Shelf. After a marine sanctuary has been designated, no Federal license or permit (and presumably lease) can be granted for activity within the sanctuary without the Secretary of Commerce's certification that such activity will not be inconsistent with the purposes of this Act. This Act could have application to OCS activity in the future since the site of the Civil War ironclad U.S.S. *Monitor* off the coast of Cape Hatteras, N.C., has been designated a marine sanctuary, and there has been speculation that oil and gas deposits are present off the coast of North Carolina in this vicinity.[18]

Additionally, the Federal Water Pollution Control Act Amendments of 1972 [19] is applicable to water pollution, including oil, in the waters of the United States and the contiguous zone (12 miles seaward).

Other laws which are specifically referred to in the OCS Lands Act as being applicable to activity carried out under the Act include: The Longshoremen's and Harbor Workers' Compensation Act[20] (compensation for injury or death of any worker); the National Labor Relations Act[21] (labor practices); and Coast Guard and U.S. Army Corps of Engineers authority over navigational aids (Coast Guard), safety (Coast Guard), and obstructions to navigation (Army).

Therefore, when looking at the OCS Lands Act, it is important not to look at it in isolation but rather to view it in light of other applicable laws. Nor is there any intention to infer that these are all of the laws that may apply.

B. *Leasing Procedures*

The OCS Lands Act provides that the Secretary of the Interior may lease tracts (no larger than 5,760 acres each) on the OCS to the "high-

[15] Pub. Law 91-190, 83 Stat. 852 (1970); 42 U.S.C. 4321-4347.
[16] Pub. Law 92-583, 86 Stat. 1280 (1972); 16 U.S.C. 1451-1464.
[17] Pub. L. 92-532, 86 Stat. 1061 (1972); 16 U.S.C. 1431-1434.
[18] See "OCS Oil and Gas: An Environmental Assessment." A Report to the President by the Council on Environmental Quality. April, 1974. See Chapter 2.
[19] Pub. L. 92-500, 86 Stat. 816 (1972); 33 U.S.C. 1251-1376.
[20] 44 Stat. 1424 (1927); 29 U.S.C. 151 et seq.
[21] 61 Stat. 136 (1947); 29 U.S.C. 151 et seq

est responsible qualified bidder", through competitive bidding (with sealed bids) for a term of five years[22] or for as long as oil or gas is being produced in paying quantities, or with the approval of the Secretary, for as long as drilling or well reworking activity is conducted on the tract. The Act authorizes the Secretary to hold the bidding on the basis of either a cash bonus with a fixed royalty (not less than 12½ percentum), or a royalty (again, not less than 12½ percentum) with a fixed cash bonus.[23] Also, the Secretary is authorized to set a rental fee at the time of the lease.[24] The authority of the Secretary under the OCS Lands Act has been delegated to the Bureau of Land Management (BLM) (for leasing) and the U.S. Geological Survey (USGS) (for exploration and development operations.)

The actual leasing process entails the following chronology:[25]

1. Environmental Baseline Studies

Following the gathering of resource data through geological and geophysical exploratory activity, the general areas of possible lease sales are identified. At that time in the process environmental baseline studies are initiated, if, as pointed out in the Proposed OCS Planning Schedule (June 1975) published by BLM (see Figure 11), personnel and equipment are available to conduct such studies.[26] When conducted the purpose of the baseline studies is to obtain a benchmark from which future environmental observations can be compared. The studies cover many, varied scientific areas and are usually conducted through contracts with universities, the National Oceanic and Atmospheric Administration (NOAA) or USGS. The results of the studies are used "by the Department (Interior) in making management decisions regarding the mineral resources."[27]

2. Resource Evaluation

The Director of BLM when considering or announcing tentative leasing schedules in the OCS, will request the USGS to furnish him with a report of the geologic conditions and the mineral resource potential of the area being considered. He will also request from other interested Federal agencies reports on "other valuable resources" in the area and the potential effects that the mineral operations will have on these resources and on the environment generally.[28] Although the BLM regulations do not provide specifically for State input at this stage, the U.S. Geological Survey Circular 720[29] indicates that resources reports are requested from the Governor of the adjacent State. The resource reports are generally made at least 30 days before the call for nominations.[30]

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[22] Sulphur leases are for a period of 10 years, with a royalty rate of not less than 5 percentum.

[23] 43 U.S.C. 1337. The first bidding system (cash bonus with fixed royalty) is the one most commonly used. The royalty bidding system has only been used once in lease sales held since 1954, and that was in September, 1974. The royalty has been fixed by the Secretary at 16⅔%.

[24] The annual rental or minimum royalty has been set by the Secretary at $3.00 per acre for unproven areas and $10.00 per acre for leases in proved areas. Adams M. V., et al. "Mineral Resource Management of the Outer Continental Shelf," Geological Survey Circular 720, U.S. Geological Survey, Reston, Va., 1975, p. 4.

[25] The leasing process is generally preceded by geological and geophysical exploraation (i.e. gravimetric and seismic surveying, bottom sampling, and coring) which is authorized by permit from the Area Oil and Gas Supervisor of USGS. No exploratory drilling is permitted prior to a lease.

[26] Ibid.

[27] U.S. Dept of the Interior. Geological Survey. "Mineral Resource Management of the Outer Continental Shelf," Circular 720. Washington, D.C. (1975). p. 9.

[28] 43 C.F.R. § 3301.2.

[29] U.S. Dept. of the Interior, op. cit., p. 10.

[30] Ibid.

3. Call for Nominations

The Director, BLM, with the approval of the Secretary, notifies the industry and the public by publication in the Federal Register that he will accept nominations of desirable tracts which may subsequently be offered for lease. The call for nominations also serves as an opportunity for the States and the public to submit negative nominations; that is, suggest that for environmental, economic or technical reasons, certain tracts should not be offered for lease.[31]

The call for nominations is not the only procedure whereby tracts may be selected for subsequent lease sale. The BLM regulations also provide that "the Director will receive and consider nominations" of specific tracts submitted by industry without a formal call for nominations having been made.[32] All nominations are submitted to the Director with copies to the local BLM field office and the local Area Oil and Gas Supervisor of USGS. In turn, USGS makes recommendations to the Director relative to tract selections, and terms and conditions to be included in any subsequent lease.[33]

4. Tract Selections

Generally within 30 to 60 days after the publication of the call for nominations, the nominations are due (see Figure 11) to be submitted to the Director. From those nominations submitted, whether positive or negative in nature, the Director selects a list of possible tracts to be included in a lease sale. This selected list is an announced to the public by publication in the Federal Register, and by a news release.[34] According to the most recent Proposed OCS Planning Schedule (Figure 11), the announcement of tracts is usually made 60–90 days following the due date for nominations.

5. Environmental Impact Statement (EIS)

(*a*) *Draft EIS.*—Once the tentative lease tracts are selected, BLM, with the assistance of USGS, prepares a draft EIS. This process is intended to include input from environmental groups, State and local governments, the academic community and others. The statement includes an analysis of the following: (1) a description of the proposed activity, (2) description of the environment, (3) the environmental impacts of the activity, (4) mitigating measures, (5) unavoidable adverse environmental effects, (6) the relationships between local short-term uses and long-range productivity, (7) the irreversible and irretrievable commitment of resources, (8) the alternatives to the proposed activity, and (9) the coordination and consultation employed. Upon completion the draft EIS is submitted to the Council on Environmental Quality (CEQ) for their review and comments; and a notice of its availability is published in the Federal Register, and released to the news media through a news release.[35]

BLM regulations provide that public hearings *may* be held after notice,[36] but it appears that no decision on a lease sale will be made

[31] Ibid.
[32] 43 C.F.R. § 3301.3.
[33] Ibid.
[34] U.S. Dept. of the Interior, op. cit., p. 10.
[35] Ibid.
[36] 43 C.F.R. § 3301.4.

until a public hearing is held (see Figure 11). Generally this is held between 30–60 days after completion of the draft EIS. The public, as well as industry, environmental groups, and government, are permitted to testify orally or in writing and thus present their views, which are "considered in the preparation of the final environmental statement." [37]

(*b*) *Final EIS.*—The final environmental statement is compiled from the comments obtained at the public hearing and from other comments received during the review process, including those of CEQ. In addition to the revised analysis of those matters contained in the draft EIS, the final statement includes an expanded section on consultation and coordination with others, which includes the comments received through the public hearing process or otherwise. The final EIS, like the draft statement, is submitted to CEQ and notice of its availability is published in the Federal Register and released to the news media.[38]

6. Lease Sale

Subsequent to the completion of the final EIS and a decision having been made to hold a lease sale, notice of the sale is published in the Federal Register at least 30 days prior to the sale. This notice sets forth the particulars as to time, place and date of the sale and any special terms or conditions that will be applicable to specific tracts.[39]

The bids are opened at the time and place and on the date set forth in the notice. Each bid must be accompanied by a check, money order, or bank draft in the amount of 20 percent of the bid.[40] No decision is made as to the winning bid, if any, at that time. The bids are only opened for the purpose of public disclosure. The decision of whether to accept the highest bid must be made within 30 days of the opening of bids or all bids are automatically rejected.[41] The highest bidder upon being notified of his bid being accepted must pay the first year's rental, the remainder of the bonus bid, and file a bond within a specified time period. If the successful bidder refuses to execute the lease, he forfeits the 20 percent of the bonus already deposited.[42]

The decision of whether to accept or reject the highest bid is based on a post-sale evaluation, which includes a resource evaluation conducted by USGS and carried out during the period after the announcement of tract selections and during the preparation of the EIS. This resource evaluation entails an analysis and estimate of the resource potential of specific tracts. These estimates, according to Circular 720,[43] are submitted to BLM after the lease sale is held. The resource estimates, and the determined resource value, are compared with the bids received to determine if the fair market value on a particular tract will be received by accepting the highest bid. When the Director, BLM decides that the highest bid will be accepted, the lease is executed and becomes effective on the first day of the month following the date of signing, unless an earlier date is requested.[44]

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[37] U.S. Dept. of the Interior, op. cit., p. 11.
[38] Ibid.
[39] 43 C.F.R. § 3301.5.
[40] 43 C.F.R. § 3302.4.
[41] 43 C.F.R. § 3302.5.
[42] Ibid.
[43] U.S. Dept. of the Interior, op. cit., p. 11.
[44] 43 C.F.R. § 3302.7.

C. Management Scheme

The primary Federal agency, by reason of the authority delegated by the Secretary of the Interior, with oversight responsibility over mineral resource operations in the OCS is USGS. That responsibility includes construction oversight, exploration and production control, safety and environmental protection.

Even after acquiring a lease, the lessee must apply for and receive a permit from USGS before commencing exploratory drillings.[45] The application must include specific information relating to drilling depths, locations, casing and safety equipment; and is accompanied by an exploration plan, required by 30 CFR § 250.34, which must include a description of the drilling method, safety and pollution measures to be used; location of proposed wells; geological and geophysical interpretative data; and other pertinent information required by the local Area Oil and Gas Supervisor. The plan is reviewed by USGS, particularly for safety and pollution requirements, and if a hazard exists the plan must be revised. When USGS is satisfied with the plan the permit is issued.

In addition to the regulations set out in Title 30, Chapter II, Part 250, of the Code of Federal Regulations, the local Area Oil and Gas Supervisor, with the approval of the Chief of the Conservation Division of USGS, may issue OCS Orders which are used to implement "the requirements of the regulations of this part when such implementations apply to an entire region or a major portion thereof."[46] There have been 12 orders issued to date for the Pacific Region, and they are: (1) making of wells, platforms, and fixed structures; (2) drilling procedures; (3) plugging and abandonment of wells; (4) suspensions and determinations of well productivity; (5) installation of subsurface safety devices; (6) procedure for completion of oil and gas wells; (7) pollution and waste disposal; (8) approval procedure for installation and operation of platforms; (9) approval procedures for pipelines; (10) drilling of twin core holes; (11) oil and gas production rates, etc; and (12) public inspection of records. Similar OCS orders have been issued for the Gulf of Mexico Area; and the only significant difference is OCS Order No. 10, which in the Gulf of Mexico deals with sulphur drilling procedures off Louisiana and Texas.

Once oil or gas is discovered in commercial quantities and the lessee desires to produce it, the lessee must file a development plan with the supervisor prior to commencing development.[47] The plan must include the same information required for the exploratory drilling plan. The drilling permit requirements of 30 C.F.R. § 250.91 also apply to development wells, unless field rules have been adopted for the individual field, in which case drilling must conform to those rules.[48]

The USGS has the responsibility to oversee OCS activity at all phases of operations. Through the use of records, reports and inspec-

[45] 30 C.F.R. § 250.91.
[46] 30 C.F.R. § 250.11.
[47] 30 C.F.R. § 250.34.
[48] U.S. Department of the Interior. Geological Survey. Conservation Division. Branch of Oil and Gas Operations. Pacific Region. OCS Order No. 2. June 1, 1971.

tions, USGS should have the ability to keep abreast of OCS activity, including drilling experiences, production and conservation, pollution, and safety.

In the interests of conservation, lessees can request or USGS can require unitization of production. This may occur in those instances where more than one lessee is developing resources from the same hydrocarbon field or reservoir. Because of the tendency for each operator to develop the reservoir as quickly as possible to maximize his return, unitization is employed to eliminate unnecessary drilling, reduce production costs and to protect the rights of all interested parties.[49] Unitization may also be used to develop adjacent fields from fewer platforms, which would not only reduce the number of rigs dotting the ocean but reduce the costs of production when more than one field is drilled from a single platform.

Another conservation measure involves the rates of production. USGS controls production through the establishment of the maximum efficient rate (MER) of production and the maximum production rate (MPR). The MER is established for each producing reservoir "based on sound engineering and economic principles," [50] while the MPR is established for each producing well.[51] After the rates have been established, an operator may not exceed the MER or MPR without first obtaining permission from the local Area Oil and Gas Supervisor. The purpose for the production rates is to insure, to the maximum extent possible, the ultimate recovery of oil or gas from each reservoir.[52]

The lessee has the responsibility to assure that his OCS operations are both safe and clean. The USGS regulations, specifically 30 C.F.R. § 250.43, require that the lessee not pollute the water, or damage aquatic life by OCS activity; and that he immediately report substantial spills or leaks to the Supervisor, and uncontrolled spills or leaks to the Supervisor, the Coast Guard, and the Regional Director of the Federal Water Pollution Control Administration (now Environmental Protection Agency by Reorganization Plan No. 3 of 1970; 42 U.S.C. 4321 note). Also the lessee is responsible for the clean-up costs whether carried out by the lessee or by any local, State or Federal agency. In OCS Order No. 7, the responsibility is placed upon the operator to properly dispose of wastes, inspect and report *all* spills and leakage, and control and remove pollutants. Both USGS and the Coast Guard have authority to impose certain safety requirements upon platforms used in OCS operations. In some cases the Authority overlaps. For example, the USGS, by OCS order No. 8 (Pacific Region) of June 1, 1971, requires that fire-fighting equipment be maintained on platforms, which is also required by Coast Guard regulation.[53]

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[49] U.S. Department of the Interior, op. cit., pp. 24–25.

[50] U.S. Department of the Interior. Geological Survey. Conservation Division. Branch of Oil and Gas Operations. Pacific Region. OCS Order No. 11. May 1, 1975, pp. 11–3.

[51] Ibid., pp. 11–4.

[52] U.S. Department of the Interior. Geological Survey. Conservation Division. Branch of Oil and Gas Operations. Pacific Region. OCS Order No. 7, June 1, 1971, pp. 7–2.

[53] 33 C.F.R. § 145.01 et seq.

OVERSIZE FOLDOUT(S) FOUND HERE IN THE PRINTED EDITION OF THIS VOLUME ARE FOUND FOLLOWING THE LAST PAGE OF TEXT IN THIS MICROFICHE EDITION.

SEE FOLDOUT NO. 1

PROPOSED OCS PLANNING SCHEDULE

JUNE 1975
(REVISES NOVEMBER 1974 SCHEDULE)

SALE AREA		1974						1975											
		J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
SOUTH TEXAS	37		DES	PH		BSI DES		N	Sale					S	A	L	E		H
CENTRAL GULF	38	ND			T		DES, DES	PH PH		FES FES	N	Sale							S
CENTRAL GULF	38A	ND			T		DES	PH		FES	N			Sale					
SOUTHERN CALIF.	35		T						DES			PH	BSI		FES	N	Sale		
COOK INLET	1/	F	E	D	E	R	A	L		-		S	T	A	T	L		S	A
GULF OF ALASKA	39	BSI				C	ND			T			DES		PH		FES	N	Sale
GULF OF MEXICO (GENERAL)	41						C	ND		T				DES		PH			FES
MID-ATLANTIC	40									C			BSI ND		T		DES		PH
NORTH ATLANTIC	42												C		ND	BSI	T		
GULF OF MEXICO (DRAINAGE)	44																		T
SOUTH ATLANTIC	43													C			BSI ND		
GULF OF ALASKA (INCLUDING KODIAK)	46													BSI			C		ND
BERING SEA (ST. GEORGE)	45						C	ND				BSI		T					
GULF OF MEXICO (DEEP)	47																		
SO. CALIFORNIA	48																		
MID-ATLANTIC	49																	BSI	
BEAUFORT SEA	50											BSI							
OUTER BRISTOL BASIN	51											BSI							
NORTH ATLANTIC	52															BSI			
CALIFORNIA GENERAL INCL. WASH. & OREGON	53																		
SOUTH ATLANTIC (BLAKE PLATEAU)	54																		
BERING SEA (NORTON BASIN)	55																		
GULF OF ALASKA – ALEUTIAN SHELF	56													BSI					
CHUKCHI SEA HOPE BASIN	57																		

SALE AREA		1976												1977											
		J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
SOUTH TEXAS	37	E	L	D		I	N		F	E	B	R	U	A	R	Y		1	9	7	6				
CENTRAL GULF	38	A	L	E		H	E	L	D		I	N		M	A	Y		1	9	7	6				
CENTRAL GULF	38A																								
SOUTHERN CALIF.	35																								
COOK INLET	1/	L	E		-		D	A	T	E		U	N	C	E	R	T	A	I	N					
GULF OF ALASKA	39																								
GULF OF MEXICO (GENERAL)	41	N	Sale																						
MID-ATLANTIC	40			FES	N	Sale																			
NORTH ATLANTIC	42	DES		PH			FES	N	Sale																
GULF OF MEXICO (DRAINAGE)	44			DES		PH			FES	N	Sale														
SOUTH ATLANTIC	43	T			DES		PH			FES	N*	Sale													
GULF OF ALASKA (INCLUDING KODIAK)	46		T			DES		PH			FES	N	Sale												
BERING SEA (ST. GEORGE)	45								DES		PH			FES	N	Sale									
GULF OF MEXICO (DEEP)	47	C		ND			T			DES		PH			FES	N/	Sale								
SO. CALIFORNIA	48			C		ND			T			DES		PH			FES	N	Sale						
MID-ATLANTIC	49					C		ND			T			DES		PH			FES	N	Sale				
BEAUFORT SEA	50							C		ND			T			DES		PH			FES	N	Sale		
OUTER BRISTOL BASIN	51									C		ND			T			DES		PH			FES	N	Sale
NORTH ATLANTIC	52											C		ND			T			DES		PH			FES
CALIFORNIA GENERAL INCL. WASH. & OREGON	53								BSI					C		ND			T			DES		PH	
SOUTH ATLANTIC (BLAKE PLATEAU)	54	BSI														C		ND			T			DES	
BERING SEA (NORTON BASIN)	55			BSI														C		ND			T		
GULF OF ALASKA – ALEUTIAN SHELF	56																			C		ND			T
CHUKCHI SEA HOPE BASIN	57							BSI														C		ND	

SALE AREA		1978											
		J	F	M	A	M	J	J	A	S	O	N	D
SOUTH TEXAS	37												
CENTRAL GULF	38												
CENTRAL GULF	38A												
SOUTHERN CALIF.	35												
COOK INLET	1/												
GULF OF ALASKA	39												
GULF OF MEXICO (GENERAL)	41												
MID-ATLANTIC	40												
NORTH ATLANTIC	42												
GULF OF MEXICO (DRAINAGE)	44												
SOUTH ATLANTIC	43												
GULF OF ALASKA (INCLUDING KODIAK)	46												
BERING SEA (ST. GEORGE)	45												
GULF OF MEXICO (DEEP)	47												
SO. CALIFORNIA	48												
MID-ATLANTIC	49												
BEAUFORT SEA	50												
OUTER BRISTOL BASIN	51												
NORTH ATLANTIC	52	N	Sale										
CALIFORNIA GENERAL INCL. WASH. & OREGON	53		FES	N	Sale								
SOUTH ATLANTIC (BLAKE PLATEAU)	54	PH			FES	N	Sale						
BERING SEA (NORTON BASIN)	55	DES		PH			FES	N	Sale				
GULF OF ALASKA – ALEUTIAN SHELF	56			DES		PH			FES	N	Sale		
CHUKCHI SEA HOPE BASIN	57		T			DES		PH			FES	N	Sale

BSI Baseline Studies Initiated
C Call for Nominations
ND Nominations Due
T Announcement of Tracts
DES Draft Environmental Statement
PH Public Hearing
FES Final Environmental Statement
N Notice of Sale
1/ State May Conduct Sale

Baseline studies scheduled are contingent upon scientific personnel and equipment being available to perform the studies.
Sales are contingent upon technology being available for exploration and development. A decision whether to hold any of the lease sales listed will not be made until completion of all necessary studies of the environmental impact and the holding of public hearings, as a result of the environmental, technical, and economic studies employed in the decision-making process, a decision, may, in fact, be made not to hold any sale on this schedule.

Director,
Bureau of Land Management

FIGURE 11

II. PROPOSED CHANGES

The OCS Lands Act was enacted in 1953, and to this date has never been amended. There has been criticism of the existing law, and since it is 22 years old, many efforts over the last few years have been directed at amending the Act. None as yet has been successful. In the 94th Congress there have been bills introduced in both Houses to amend the OCS Lands Act and the following discussion will focus on some of the major features of those proposals.

A. Bidding Systems

As mentioned earlier, there are two bidding systems presently authorized by the OCS Lands Act.[54] The first, and the one used in every lease sale since 1953, except for one in September 1974, is the cash bonus bidding with a fixed royalty of not less than 12½ percent. The other is where the cash bonus is fixed and a royalty is used as the bidding variable. The cash bonus bid system has been criticized in recent years for favoring the major oil companies and possibly not providing the highest return to the public for its resources. As a result the legislation introduced, which revises the bidding system, has included a wide variety of systems which will be available to the Secretary. The reason for the many, varied systems being proposed is that it simply is not known which will produce more oil or gas from the OCS, while maximizing the return to the public.[55] Therefore, it is intended that through experimentation with the varied systems, the best system will evolve. The new systems then are designed to reduce front end bonus money and thereby make more money available for exploration, as well as making it possible for the smaller companies to better compete in the OCS development field. Also it is hoped that the new systems will result in more return to the public for the OCS mineral resources.[56]

The new systems include various aspects of royalty bidding, net profit sharing and undivided working interest bidding.

Fixed or Variable Royalty.—As mentioned earlier the use of a royalty as the bid variable with a fixed cash bonus is the second system presently authorized by the OCS Lands Act; and even though it has been used in only one lease sale in the 22-year history of the Act, a variation of the royalty as a bid variable has been proposed which would entail setting the fixed cash bonus high enough to cover (or at least estimate) an adequate exploratory drilling program for the tract being offered for lease. The cash bonus deposited would then be available for 50 percentum grants in such amounts as the lessee shall need to carry out an exploratory program. An alternative to such grants, would be the deferral of cash bonus payments for up to three or five years. The obvious advantage of this system would be that more money would be available for exploration; but would undoubtedly lead to higher royalty bids, which in turn could lead to premature abandonment of a tract because of the lower return to a company as the resources diminish. Another proposed method which is designed to encourage continued production as resources decrease is where, like the present method, there is a cash bonus bid but the royalty would be set on a sliding or diminishing scale to avoid early

[54] 43 U.S.C. 1337.
[55] U.S. Congress. Senate. Committee on Interior and Insular Affairs. Outer Continental Shelf Management Act of 1975. Report to Accompany S. 521. Washington, U.S. Govt. Print. Off., 1975. (94th Congress, 1st session. Senate. Report No. 94-284), p. 6.
[56] Ibid.

abandonment. However, since the bid variable would continue to be based on a cash bonus, this system would not appear to encourage or induce more participation by smaller companies.

Net Profit Share. Net profit sharing is the system whereby government would receive a share of the net profits from the venture rather than receive a royalty. It has been argued that net profit sharing has the advantages of reducing the front-end cash bonuses, while sharing the risk of the effort. The purpose of reducing the cash bonus is to encourage smaller producers to participate in OCS development. However, one of the proposals for net profit sharing involves the use of cash bonus as the bid variable [57] and therefore, the role of the cash bonus may not be altered sufficiently to allow smaller producers to adequately compete in the OCS. Net profit sharing would undoubtedly spread some of the risk to the government. Under the present royalty system the government simply receives a $\frac{1}{16}$ portion, in value or amount, of the oil or gas recovered. If the government were to receive instead a share of the net profits, its share would in effect be dependent, among other things, on the costs of recovering the resources. The concern with this system is with the administrative problems created by accounting and auditing requirements; and whether capital recovery will be permitted.

The proponents of this system point out that it would require less money, in the form of cash bonus—particularly where the cash bonus is not used as the bid variable, to successfully acquire a bid; and, since less front-end money will be needed, more money would be available for exploration. The high cash bonuses paid for a lease at the present time is the major reason that the present cash bonus system has been criticized since it ties up large sums of money that could be better used. Therefore the advantages of the net profit sharing system would include the reversal of the present experience, which entails the payment of larger sums to obtain a lease and lower government payments when production occurs. This would appear to be especially true when bids are made on a percentage of the working interest in the venture.

Working Interest. A proposal which is used in conjunction with the net profit sharing proposal is where the bidders submit a bid on 1 percentum of the working interest in the lease area. This bid variable is used either with a fixed net profit share or a sliding or diminishing net profit share or royalty. Thus the successful bidders would form a blind joint venture which would allow more smaller producers to participate in OCS development.

By authorizing various methods of bidding, the Department of the Interior can experiment with the varied systems in an attempt to arrive at the system best suited to increase domestic production of oil and gas while assuring a fair return for the public resources.

B. *Federal Exploration*

One of the more controversial proposals included in pending legislation is the provision that would allow the Federal government to conduct, either on its own or by contract, exploration in the OCS. The argument for this provision is that the government holds the OCS in trust for people of the United States; and as trustee the government

[57] Ibid., p. 77.

has the responsibility to administer the public's land in a manner that insures that the public receives a fair market return for its mineral resources. The argument continues that under the present leasing system, the OCS tracts are leased before the government (or the companies for that matter) know how much oil and gas are present in the OCS; and, therefore, there is no accurate way to calculate whether the public is receiving a fair market return for the resources, even though the government does receive substantial cash bonuses in some cases. The fact still remains that even with the high bonuses and a royalty payment of 16-2/3 percentum *no one* knows whether the public is receiving its fair return. Therefore, it is argued that the government, like any private individual, should know what it is selling before it sells the public's resources. To do this, the proponents argue, the government should find out, to the fullest extent possible, what quantity of oil and gas is present in a particular lease area before it sells it to the highest bidder.

Under the present system, no exploratory drilling (drilling directly over a suspected deposit to determine if oil or gas is present) is conducted prior to a lease sale. Rather only geological and geophysical exploration is carried out, which entails seismic surveying, gravimetric surveying, coring, and stratigraphic drilling (off structure drilling to determine the geologic conditions of the area but not to actually find oil or gas). There is apparently no argument over the fact that until exploratory drilling actually commences, there is no way to conclusively determine whether any oil and gas is present in a particular area. In view of this, proponents of Federal exploration contend that the government should carry out an exploratory program to determine to the extent possible how much oil and gas is present in an area scheduled for a lease sale. This could be accomplished by contracting with the same companies used by the oil companies.[58]

The opponents of Federal exploration argue that if the government gets into the business of exploring for oil and gas in the Outer Continental Shelf, it is only a matter of time before the Federal government takes over the petroleum industry entirely. The government should not be entering into a field of private enterprise, the argument continues, because the private sector is better qualified in view of its many years of experience to conduct such activity. Not only does the government lacks the necessary experience to efficiently carry out such a program, but due to the political structure of this country such government activity would produce havoc in the development of these resources. The decision of where, when and how to drill even an exploratory hole, and how many exploratory wells will be drilled, will rest in one person (whether the Secretary of the Interior or the President), when under the present system these decisions are made by many people in many different companies. To reduce that decision-making process to one person—and in a political position at that—would be economic and political disaster, not to mention resulting in delays and the recovery of less oil and gas.[59]

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[58] See generally U.S. Congress. Senate Committees on Interior and Insular Affairs, and Commerce. Outer Continental Shelf Lands Act Amendments and Coastal Zone Management Act Amendments. Joint Hearings, 94th Congress, 1st session, Washington, U.S. Govt. Print. Off. 1975. Parts 1 and 2.

[59] Ibid.

On July 30, 1975, the Senate by a vote of 67 to 19, passed S. 521 (Outer Continental Shelf Management Act of 1975), which provides for a limited exploration to be carried out by the Secretary of the Interior. It authorizes exploratory drilling by contract on an experimental basis; but, only in areas that are not included in the leasing program,[60] which the Secretary is required to develop. The exploratory program was added as a floor amendment to S. 521. In the House of Representatives, the Ad Hoc Select Committee on the Outer Continental Shelf [61] is considering a similar bill (H.R. 6218) that does not include a Federal exploratory program, although the committee is considering such a proposal. The Select Committee is presently (March 1976) marking up H.R. 6218, and, therefore it is not possible to determine what if any provision relating to Federal exploration will emerge from the House; and if one does what differences will need to be worked out in conference with the Senate.

C. *Separation of Exploration from Development and Production*

Many States and environmental groups have advocated that exploration of the OCS should be separated from the subsequent development and production phases.[62] The reasoning is that prior to exploration, it is not known what resources are present; and, therefore, there is no assurance that the environmental impact statement which was drafted prior to the lease sale will be adequate in light of the actual experiences of exploration. The States only have the estimates of potential resources to use in preparing for the resulting onshore impacts, which may vary greatly from the resources discovered during exploration. Finally, due to the experience of exploratory activity it may be undesirable to continue with development and production of the OCS, but under existing law there does not appear to be a way to terminate the lease or to prohibit further activity unless the terms of the lease are violated.[63]

Thus there have been proposals in the 94th Congress to make a clear distinction between exploration, and development and production.

Section 206 of S. 521, provides that before development or production commences, a plan must be submitted and approved by the Secretary. The proposed development and production plan must also be submitted to the Governors of the affected coastal States for their review and comments. Although the proposal does not provide the States with a veto over the plan, nor the right to request a delay, the respective State comments are made a part of the record upon which the Secretary makes his decision, which would be subject to judicial review pursuant to the Administrative Procedure Act.[64] The important aspect of the provision which requires the submission of a development and

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[60] Section 202 of S. 521, adds, inter alia, a new section 18 to the OCS Lands Act which directs the Secretary of the Interior to prepare and maintain a leasing program that indicates the size, timing, and location of leasing activity over the next five years to meet national energy needs.

[61] On April 22, 1975, the U.S. House of Representatives passed H. Res. 412 which established the Ad Hoc Select Committee on the Outer Continental Shelf, which is composed of members from the House committees on Judiciary, Merchant Marine and Fisheries, and Interior and Insular Affairs. H.R. 6218 is the only bill which has been referred to the Select Committee.

[62] U.S. Congress. Senate. Committees on Interior and Insular Affairs, and Commerce. op cit.

[63] *Union Oil Company of California* v. *Morton*, 512 Fed 743 (CA 9.1975).

[64] Pub. L. 89–554, 80 Stat. 392 (1966); 5 U.S.C. 701 et seq.

production plan is that the Secretary can—after exploration—disapprove development and production if he determines that the plan cannot comply with the requirements of the Act (S. 521) or other Federal law; or because of extraordinary resource values, environmental considerations, geologic conditions, or other extraordinary circumstances, the plan cannot assure safe operations.

D. Oil Spill Liability

Although the Department of the Interior has by regulation [65] and by OCS Order No. 7 (Gulf of Mexico and Pacific Regions) established that a lessee is responsible for preventing pollution and, where pollution does occur, for all clean-up costs, it does not go as far as proposals in the 94th Congress which would toughen this responsibility and the liability under the OCS Lands Act. Some proposals impose strict liability, which means that in the event of an oil spill, the lessee is held responsible without regard to fault unless he can show that the pollution was caused by an act of war, solely by the negligence of the United States or other governmental agency, or solely by the negligence or intentional act of the party claiming damages. Another aspect of the pending legislation is the establishment of a fund for the purpose of compensating for the damages caused by oil pollution. Although the lessee would be liable for the damages up to a certain amount, the fund, which would receive money from the production itself, would be liable for damages that exceeded that amount. Under present law the liability of the lessee to third parties "shall be governed by applicable law"; [66] but one of the proposals pending in Congress [67] would authorize persons damaged as a result of an oilspill to collect against the lessee and the fund. This remedy would extend to persons, such as fishermen and resort owners, who were damaged economically eventhough they did not own the fish or beaches that were damaged.

In S. 521, the assistance to the States is in the form of grants and loans for adverse impacts; automatic grants based on an amount per barrel of oil or gas landed in or produced adjacent to a coastal State; and, bond guarantees by the Federal government for local or State bonds or other evidences of indebtedness. These forms of assistance are provided to the States in recognition of the legitimate environmental, economic and social impacts on the States which are likely to result from OCS activity while at the same time taking into consideration the national interest in finding and producing more energy for the Nation.

F. Governmental Coordination

Another proposal deals with the concerns that the coastal States are not adequately consulted nor advised of the Federal decisions dealing with the OCS activity in advance of those decisions. The States believe that if they are to satisfactorily plan for and ameliorate the impacts which will likely occur as a result of the OCS development the States must have an input into the Federal policy and decision processes before decisions actually occur. As a result S. 521, as one example, proposes more State participation in the Federal decision process. The

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[65] 30 C.F.R. 250.43.
[66] 30 C.F.R. § 250.43(c).
[67] See section 202, S. 521 (94th Congress) which adds a new section 23 to the OCS Lands Act.

State input would be encouraged in the formative stages of the development and production plans, environmental impact statements, and leasing plans. It is not intended as mentioned earlier that the States should have a veto power over Federal decisions dealing with Federal lands on the OCS. Rather the purpose of this proposal is to give the States as much input into the process as possible so that State concerns will be given every consideration in, and incorporated where possible into, the Secretary's decisions. One method includes a regional advisory board which would consist of representatives from neighboring States with common problems, and Federal observers, who would participate in the meetings of the boards. The idea is to create an effective forum for Federal-State coordination.

CHAPTER III. JURISDICTION OVER OFFSHORE PETROLEUM DEVELOPMENT: THE COASTAL STATES AND THE FEDERAL GOVERNMENT

The jurisdiction of the United States over the exploration and exploitation of the continental shelf is fairly well settled in the area of international law; [1] however, the question of jurisdiction between Federal and State Government is still an area of some controversy. The Federal-State dispute, at times referred to as the "tide-lands controversy", is a longstanding one which has recently attained a special relevance due to the realization that the present energy supply is not unlimited. This portion of the study will deal with the jurisdictional aspects of continental shelf petroleum developments. First, there will be a brief discussion of the background of the controversy, including a discussion of significant statutes and cases. The recent Supreme Court cases of *United States* v. *Alaska* and *United States* v. *Maine* will then be analyzed. Finally, legislation dealing with the relationship of Federal and State powers will be discussed briefly.

In 1845 the Supreme Court held that the states had an absolute right to all navigable waters and the soil underneath them subject to the rights surrendered to the Federal Government by the Constitution. This holding was upheld for the ensuing one hundred years.[2] However, in 1937 the Federal Government began to assert jurisdiction over this area, and in 1947 the Supreme Court rejected the earlier decisions by holding that the United States had "paramount rights" over the area three miles seaward from the normal low-water mark on the California coast.[3] Similar decisions were later made with respect to lands lying off the Louisiana and Texas coasts.[4] In response, Congress enacted the Submerged Lands Act of 1953 which its sponsors claimed would restore to the coastal states the offshore lands that were considered to be theirs prior to *United States* v. *California*.[6]

The Submerged Lands Act quitclaimed to the coastal states all the lands underlying "navigable" waters within their boundaries. Boundaries were defined as—

> * * * the seaward boundaries of a State or its boundaries in the Gulf of Mexico or any of the Great Lakes as they existed at the time such State became a member of the Union, or as heretofore approved by Congress or as extended. * * *

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[1] In 1945 the United States asserted its claim to the continental self in President Truman's Proclamation on the Contentinental Shelf, 10 Fed. Reg. 12304 (1945); 59 Stat. 885. This claim has been recognized by the Convention on the Continental Shelf, 15 U.S.T. 471, 499 U.N.T.S. 311, T.I.A.S. No. 5578 (1958) which provides that "(t)he coastal State exercises over the continental shrelf sovereign rights for the purpose of exploring it and exploiting its natural resources." The use of the words "coastal state" refers to a nation that has a continental shelf off its shores and not to States such as States of the United States.

[2] Henri, "The Atlantic States' Claim to Offshore Oil Rights: U.S. v. Maine" 2 Envir. Affairs 827, 828–829 (1973).

[3] *United States* v. *California*, 332 U.S. 19 (1947)

[4] *United States* v. *Louisiana*, 339 U.S. 699 (1950); *United States* v. *Texas*, 339 U.S. 707 (1950).

[5] 43 U.S.C. §§ 1301–1315 (1970 ed.).

[6] S. Rep. No. 133, 83d Cong., 1st Sess. (1953).

but in no event shall the term "boundaries" or the term "lands beneath navigable waters" be interpreted as extending from the coast line more than three geographical miles into the Atlantic Ocean or the Pacific Ocean, or more than three marine leagues into the Gulf of Mexico * * *.[7]

However, certain powers are retained by the United States. The powers of regulation and control of these lands and the navigable waters above them for the purposes of commerce, navigation, National defense, and international affairs are reserved to the Federal government.[8] Also, specifically reserved are the rights to natural resources seaward of the land allocated to the States.[9] The Outer Continental Shelf Lands Act,[10] adopted in 1953, claimed for the United States the part of the outer continental shelf which had not been quitclaimed to the states under the Submerged Lands Act and vested the authority for these lands in the Secretary of the Interior.

In *Alabama* v. *Texas*,[11] the Supreme Court held the Submerged Lands Act to be constitutional. The Act then lay relatively forgotten since offshore mining technology had not advanced sufficiently to permit economic exploitation of petroleum beyond the three mile limit. By the end of the 1950's, however, the technology had become available and a more exact determination of the limitation of state jurisdiction in the Gulf of Mexico was sought. *United States* v. *Louisiana* [12] and *United States* v. *Florida* [13] provided this more exact determination. The Supreme Court held in those cases that the boundaries of Louisiana, Mississippi and Alabama extended only three geographical miles from their coast lines but that the historic boundaries of Texas and Florida extended for three marine leagues from their coast lines into the Gulf of Mexico.

These cases did not totally clarify the Submerged Lands Act; the problem of determination of the coastal points from which the three mile (or three league) boundary was to be measured remained. The Act defines coast line as "... the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters . . ." [14] but the interpretation of the "seaward limit of inland waters" was not clear. In *United States* v. *California*,[15] the Supreme Court held that Congress had intended to leave the definition of inland waters to the courts and that this term was to be construed in accordance with the definition in the Convention on the Territorial Sea and the Contiguous Zone.[16] The Court also provided some guidelines for the determination that (1) the federal government and the states had the choice "to use the straight-base-line method for determining inland waters claimed against other nations" as provided in Article 4 of the Territorial Sea Convention, (2) the 24-mile closing rule of the Convention does not apply to "historic" bays, (3) anchorages beyond outer harborworks are not inland waters, (4) the line of "Ordinary Low Water" was the lower low tide average, not the average of all low tides, and (5) artificial accretions can increase the states' land and extend the

[7] 43 U.S.C. § 1301(b).
[8] 43 U.S.C. § 1314.
[9] 43 U.S.C. § 1302.
[10] 43 U.S.C. §§ 1331–1343.
[11] 347 U.S. 272 (1954).
[12] 363 U.S. 1 (1960).
[13] 363 U.S. 121 (1960).
[14] 43 U.S.C. § 1301 (c).
[15] 381 U.S. 139 (1965).
[16] April 29, 1958, in force Sept. 10, 1964. 15 U.S.T. 1606, T.I.A.S. 5639.

original three-mile limit seaward, when done without the United States exercising its power over navigable waters to prevent it.

United States v. *California* also raised some problems. The Court used Article 8 of the Territorial Sea Convention to advance the "ambulatory boundary" concept, i.e., that a state may extend its seaward boundary by natural or artificial accretions to the land mass. This gave rise to a claim by Texas that the baseline from which its three marine leagues of offshore land is measured should be from its "outermost permanent harbour works." In *United States* v. *Louisiana*,[16a] the Supreme Court held that Texas was not permitted to claim more than the maximum historical limit of three marine leagues since this grant had been conditioned upon the state's prior history. In a sequel to this 1967 case, the Supreme Court decided that the Texas coast line which was to be used was the modern, ambulatory coastline, not the historic coast line.[17]

The Supreme Court also had to determine where "the line marking the seaward limit for inland waters" was on the Louisiana coast.[18] Louisiana had claimed that the line drawn under the authority of 28 U.S.C. § 102 which directed the drawing of "lines dividing the high seas from rivers, harbours, and inland waters" was the inland water line. It was also argued that due to the exercise of jurisdiction to regulate navigation, the area had been established as inland waters and that the Territorial Sea Convention should not apply to Louisiana since the coast line was so different from that of California. The Supreme Court rejected these arguments and held that the line was to be drawn in accordance with the definitions of the Convention on the Territorial Sea, consistent with the holding in *United States* v. *California*.[19] More specifically, the Court held that (1) Article 8 of the Convention did not establish dredged channels as inland waters, (2) the territorial sea was to be "measured from low tide elevations which lie within three miles of the baseline across the mouth of a bay, but more than three miles from any point of the mainland of an island," (3) when islands create multiple mouths to a bay, "the bay should be closed by lines between the natural entrance points on the islands, even if those points are landward of the direct line between the mainland entrance point," (4) an island may be treated as a headland of a bay, and (5) Federal and State exercises of authority over the disputed waters were to be examined to see if an historic title to the bays had been established.[20] Due to the technical nature of determining the precise boundaries, a Special Master was appointed. Using the above holdings as guidelines, the Special Master submitted his report on July 31, 1974 and it was accepted by the Court on March 17, 1975 despite exceptions filed by the United States and Louisiana. On June 16, 1975, a supplemental decree was filed which established the coastline of Louisiana.

The case of *United States* v. *Maine* decided March 17, 1975, is one of the most recent and most important concerning Federal-State con-

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[16a] 389 U.S. 155 (1967).
[17] *United States* v. *Louisiana*, 394 U.S. 1 (1969).
[18] *United States* v. *Louisiana*, 394 U.S. 11 (1969).
[19] 381 U.S. 139 (1965).
[20] Taylor, "The Settlement of Disputes Between Federal and State Governments Concerning Offshore Petroleum Resources: Accommodation or Adjudication?", 11 Harv. Int'l L.J. 358, 371–372 n. 82 (1970).

flicts over jurisdiction of the outer continental shelf. Its significance rests in large part on the fact that the ownership of a vast supply of natural fuel resources was at stake. Geological exploration has indicated that the Atlantic continental shelf may possess 5.5 billion barrels of oil, 37 trillion cubic feet of gas and 1.1 billion barrels of natural gas liquids in comparision to a Gulf Coast—?—of approximately 5 billion barrels.[21] The defendant states were those bordering on the Atlantic Ocean—Maine, New Hampshire, Massachusetts, Rhode Island, New York, New Jersey, Delaware, Maryland, Virginia, North Carolina, South Carolina, Georgia and Florida—and they were anxious to claim as much as possible of the oil rich Atlantic Continental Shelf.

The case began when the United States sought a declaratory judgment that:

> The United States is now entitled, to the exclusion of the defendant State(s), to exercise sovereignty rights over the seabed and subsoil underlying the Atlantic Ocean, lying more than three geographical miles seaward from the ordinary low watermark and fom the outer limits of inland waters on the coast, extending seaward to the outer edge of the Continental Shelf, for the purpose of exploring the area and exploiting the natural resources.[22]

The complaint also alleged that Maine had leased approximately 3.3 million acres in the disputed area and that this was interfering with the rights of the United States. Without acting on this motion for declaratory judgment, the Supreme Court appointed a Special Master. After deliberation, the Special Master submitted a report favorable to the United States to which the States took exception. The Supreme Court upheld the judgment of the Special Master; however, the arguments advanced by the States and the United States and the reasoning employed by the Court merit at least a brief examination.

The United States claimed the Outer Continental Shelf based on the Submerged Lands Act, the Outer Continental Shelf Lands Act and prior Supreme Court cases such as *United States* v. *California*, *United States* v. *Louisiana* and *United States* v. *Texas*. The defendant States rejected this and based their claim on English law and specific colonial grants and charters. They argued that a general property interest existed in the Atlantic sea and seabed adjacent to the colonies during the seventeenth and eighteenth centuries and that title to this was vested in the colonies as a result of their grants and charters.[23] The defendant States also denied that the Submerged Lands Act could be construed to infer that prior to its effective date they were without the power to exercise control over the disputed area and argued that their case could be distinguished from *United States* v. *California* and *United States* v. *Louisiana* since their colonial grants precede the formation of the Union and the Union held only that power which the states granted to it in the Constitution. The Supreme Court rejected these arguments, agreeing with the Special Master that *United States* v. *California*, *United States* v. *Louisiana* and *United States* v. *Texas* were controlling, and stating:

> (t)hese decisions considered and expressly rejected the assertion that the original States were entitled to the seabed under the three-mile marginal sea. They

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[21] Henri, "The Atlantic States' Claim to Offshore Oil Rights: *United States* v. *Maine*", 2 Environmental Affairs 827,827–828 (1973).

[22] *United States* v. *Maine*, 420 U.S. 515, 517 (1975).

[23] See Morris, "The Forging of the Union Reconsidered: A Historical Refutation of State Sovereignty over Seabeds", 74 Colum. L. Rev. 1056 (1974) for a detailed historical analysis of this argument.

also held that under our constitutional arrangement paramount rights to the lands underlying the marginal sea are an incident to national sovereignty and that their control and disposition in the first instance are the business of the Federal Government rather than the States.[24]

Also disagreeing with the States' interpretation of the Submerged Land Act, the Court further stated that:

* * * the rule that paramount rights to the offshore seabed inhere in the Federal government as an incident of national sovereignty . . . was embraced rather than repudiated by Congress in the Submerged Lands Act of 1953. In that legislation, it is true, Congress transferred to the States the rights to the seabed underlying the marginal sea; but this transfer was in no wise inconsistent with paramount national power but was merely an exercise of that authority.[25]

United States v. *Alaska*,[26] decided by the Supreme Court on June 23, 1975, dealt with a more specific issue than did *United States* v. *Maine;* that is, whether the body of water known as Cook Inlet was a historic bay. However, the issue was more far-reaching than it might appear at first glance since it presented a substantial question concerning the proof necessary to establish a body of water as a historic bay. Three factors were held significant in determining historic bay status: (1) the claiming nation must have exercised authority over the area; (2) that exercise must have been continuous; and (3) foreign states must have acquiesced in the exercise of authority. The lower courts had used these general guidelines but had concluded that Cook inlet was a historic bay, a holding which the Supreme Court reversed. The Supreme Court reviewed the historical evidence that there was a continuous exercise of authority over the area and found that the United States had exercised jurisdiction during the territorial period for the purpose of fish and wildlife management. However, these facts were found inadequate as a matter of law to establish historic title to the inlet. The Court also held that the third factor, acquiescence by foreign nations, was not adequately satisfied simply by the failure of any foreign nation to protest since it was not shown that the governments of those countries knew or should have known of the authority asserted.

The question of jurisdiction over the continental shelf seems to be well on the way to being resolved. However, there are still questions regarding the relationship of the Federal and States powers in this area.[27] The exploitation of the natural resources in the Outer Continental Shelf could cause adverse impacts on the coastal zones of the States. Congress has attempted to deal with this problem by the enactment of various statutes—the Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. § 1251), the Marine Protection, Research and Sanctuaries Act of 1972 (33 U.S.C. § 1401), the Coastal Zone Management Act of 1972, (16 U.S.C. § 1451) and the Deepwater Port Act of 1974 (P.L. 93–627). The 94th Congress has also been active in this area. S. 521 which passed the Senate on July 30, 1975, provides for a Coastal State Fund which would allow grants to assist the coastal States to ameliorate adverse environmental effects and control secondary social and economic impacts associated with the devel-

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[24] *United States* v. *Maine*, 420 U.S. 514, 522 (1975).
[25] *Id.*, 524.
[26] *United States* v. *Alaska*, 422 U.S. —, 43 U.S. L.W. 4825 (U.S. June, 1975).
[27] See Note, "Right, Title and Interest in the Territorial Sea: Federal and State Claims in the United States," 4 Ga. J. Int'l. and Cong. L. 463, 477–479 (1974).

opment of Outer Continental Shelf resources. The purpose of the Act is to:

> * * * provide maximum protection for the States and maximum protection for the environment, while at the same time allowing the oil companies to drill in a safe manner * * *.[28]

In addition the Department of Interior's Geological Survey, has proposed procedures for state consideration of Outer Continental Shelf[29] oil and gas development plans.

Confusion and controversy have surrounded the issue of Federal-State jurisdiction and control of the offshore petroleum resources. The recent Supreme Court cases of *United States* v. *Maine* and *United States* v. *Alaska* have shed light on the problem but there are still unresolved questions.

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[28] 121 Cong. Rec. 14288 (daily ed. July 30, 1975).
[29] 40 Fed. Reg. 42559 (September 15, 1975).

CHAPTER IV. OFFSHORE ENVIRONMENTAL IMPACT

The potential for accidental release of oil into the marine environment represents, from an ecological viewpoint, the most critical aspect of OCS development. Although there is a continual need for additional basic research on the effects of oil and other contaminants from drilling activities in the marine environment, a reasonably large body of information already exists. However, much of this information is based on laboratory studies under controlled conditions that in some cases, may not be completely applicable to natural environments. Field studies of actual spill events have produced conflicting results. For example, in a study of the effects of the Santa Barbara spill, one scientist noted that the number of marine organisms after the spill appeared to be roughly comparable to pre-spill populations and concluded that the spill's effect on marine life was negligible.[1] This conclusion has been disputed by other scientists who point out that there was no adequate baseline information available before the spill with which to make such comparisons, and that the study included no physical or chemical analysis of subtle toxic effects.[2] Whatever the long-term effects on the marine ecosystem, the short-term damage from a large spill is undeniably severe. A recent study for the Ford Foundation lists a number of effects according to whether they can be direct or may be indirectly fatal to marine life.[3] Oil can kill marine life directly through:

1. Coating and asphyxiation (example: barnacles and other intertidal organisms);
2. Poisoning through direct contact or ingestion (examples: ingestion of oil by preening birds, contact poisoning of vascular plants);
3. Exposure to water-soluble toxic petroleum components (example: subtidal fishes and invertebrates);
4. Destruction of more sensitive juvenile forms (example: fish eggs and larvae); and
5. Disruption of body insulation of warm blooded animals (example: diving birds).

Harmful indirect effects of oil pollution may include:

1. Destruction of food sources;
2. Synergistic effects that reduce resistance to other stresses;
3. Incorporation of carcinogenic and potentially mutagenic chemicals;
4. Reduction of reproductive success; and
5. Disruption of chemical clues essential to survival, reproduction, or feeding.

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[1] Straughan, D., ed. "Biological and Oceanographical Survey of the Santa Barbara Channel Oil Spill, 1969–1970." Vol. I. Biology and Bacteriology, Allan Hancock Foundation, University of Southern California, Los Angeles, 1971, 426 pp.

[2] Blumer, M. Scientific Aspects of the Oil Spill Problem. "Environmental Affairs," vol. 1, 1971, p. 54–73.

[3] Boesch, D. F., C. H. Herschner and J. H. Milgram. "Oil Spills and the Marine Environment." The Ford Foundation, 1974, 114 p.

Differences of opinion that arise are usually over the severity and consequences of these effects and observations from a given oil spill. Obviously, spilled oil will affect different organisms in different ways. Some of the more notable damage has been done to diving sea birds, to the point where the survival of some species in certain localities has been threatened.

A recent study by the National Academy of Sciences (NAS) found that conflicting reports of the biological damage following coastal oil spills can sometimes be attributed to differences in sampling procedures and analytical techniques, rather than to different environmental factors.[4] In other instances, the NAS study found, reports of damage to biota have not been placed in context of normal fluctuations of the biota caused by natural environmental changes.

The NAS report states:

> Natural calamities in the marine environment can be caused by changes in salinity, temperature, oxygen level, and the buildup of poisonous materials or gasses. Phytoplankton are subject to rapid and drastic changes within a season, with one species of diatom or dinoflagellate taking over the predominant position held by another species. These drastic changes may be caused in part by changes in temperature, light, or the availability of nutrients. These natural occurrences, causing variations in species composition, make it difficult to detect in the field changes caused by petroleum additions. If multiple natural occurrences coincide with an oil spill (such as occurred at Santa Barbara), separation of the effects of petroleum becomes difficult.[5]

This same conclusion was reached after a two-year interdisciplinary study by the Gulf Universities Research Consortium (GURC) conducted by 23 principal investigators at 20 universities in the Gulf of Mexico region. This group studied an offshore and nearshore area of Louisiana under extensive petroleum development, and a similar control site removed from the effects of petroleum operations. Seasonal variations of nutrients, water chemistry, and biota along with upwellings, and floods and muddy water from the Mississippi River were found to have a much greater impact on the ecosystem than normal petroleum activities.[6]

Data gathered over 38 years from offshore oil production in Louisiana can be useful in assessing the extent of environmental impacts in other areas. Dr. Lyle St. Amant, Assistant Director for Marine Fisheries and Coastal Management, Louisiana Wildlife and Fisheries Commission, stated before the Ad Hoc Select Committee on the Outer Continental Shelf at a hearing in New Orleans:

> Our experience indicates that the toxic effects of oil to a large extent has been exaggerated and animal, plant, and fish kills are negligible. Recovery of stressed areas usually occurs in a reasonable length of time ,but the cost of cleanup, public outcry, and emotional upheavals may be considerable.
>
> The offshore problems are minimal since equipment is floated in place, dredging is not required; all operations are from a central platform; fail-safe equipment is maximal; and surveillance and enforcement is easily attained. The presence of the structure itself has no significant ecological effect and frequently is beneficial as an artificial reef.

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[4] National Academy of Sciences. "Petroleum in the Marine Environment." Washington, D.C., 1975, 107 p.

[5] *Ibid.*, p. 32.

[6] Gulf Universities Research Consortium. "The Offshore Ecology Investigation, Final Project Planning Council Consensus Report," GURC Report No. 138, Galveston, Texas, 1974, 39 p.

Offshore problems involve: 1) Occasional spills or pollution which has not proved to be significantly toxic; 2) Navigational problems and restrictions of commercial fishing areas if platforms are improperly placed or are too dense; and 3) Sea-floor clutter and well stubs if not controlled.[7]

Some investigators point out that data gathered from one locality cannot be successfully applied to another area. Obviously, Georges Bank is not the same as the Gulf of Mexico and there are no Mississippi Rivers flowing through southern California. Each area has its own biota and environmental conditions and needs to be studied individually. This view is frequently cited as an argument for establishing a moratorium on offshore drilling in new areas until complete baseline data can be gathered. Other investigators suggest that basic information regarding environmental impacts can be transferred from one area to another because basic biological/chemical/physical processes and their functional relationships acting on organisms are the same throughout the world.[8] According to this view, reasonable first order impact projections can be made for new areas by adjusting the measurement values from more studied areas to allow for different biota, water temperatures, salinities, light penetrations, etc. and allowing for different large scale natural variations.

Long term effects on the marine environment from OCS oil and gas operations are not known and the full effects will probably never be completely known. Current evidence suggests that biological damage from OCS oil and gas operations (excluding large spills and special environments) may be minor compared to natural fluctuations or so long term that it would not be apparent unless each specific area under development and production were monitored in comparison with a similar area nearby, so that the effects of normal environmental fluctuations would be accounted for.

This would indicate that concurrent comparative studies are probably more definitive and justifiable scientifically than comparative baseline studies made before and after resource development. Such a view does not negate the need for baseline data but does reduce the emphasis on its importance, especially when used as an argument for delaying OCS development in new areas in order to gather greater and greater amounts of information. Many investigators consider the normal lag time of 3 years or more between the lease sale and the time development begins adequate for gathering sufficient baseline data, assuming a reasonable effort is funded.

The importance of continuous monitoring because of the great magnitude of natural fluctuations in the ecosystem was stressed in hearings of the Ad Hoc Select Committee. Dr. St. Amant pointed out:

> A single environmental assessment will not suffice to determine if impacts are occurring in the system. Fishery production and energy sources in the ecosystem are constantly cycling as a result of normal seasonal and annual environmental parameters. In some cases, as demonstrated in Louisiana, the seasonal stresses on the ecosystem by weather conditions, rainfall, river stages, and temperature may far overshadow incipient long-term changes from pollution, if any, or the accumulative effects of dredging and water changes in the system. It has taken Louisiana nearly fifteen years to develop the hydrographic pattern, the temperature variations, river flows, and rainfall analysis, to be able to predict the annual expected production of shrimp, oysters, and menhaden.

[7] St. Amant, Lyle S. Prepared statement to the House Ad Hoc Select Committee on the Outer Continental Shelf hearing in New Orleans, Louisiana, June 7, 1975, pp. 3, 4, and 5.

[8] Lohse, Alan. Prepared statement to U.S. House of Representatives, Committee on Science and Technology, Subcommittee on Energy Research, Development and Demonstration (Fossil Fuels), Washington, July 10, 1975, unpbl.

Without knowing the extremes of fluctations in a normal system and the factors controlling such fluctuations, it would be impossible to determine the effects of an oil spill or dredging activities with any dregree of accuracy. If for example, we had not had this type of information at the time of the Chevron and Shell oil fires in Louisiana to evaluate the effects on fish production, it is probable that the amount of litigation would have been monumental. It is imperative that the managing agency, whether it be Federal or State, operate on a continuous basis so that in the event of an accident or some other type of environmental stress, it can be determined whether a decline in a particular species of animal is a result of the incident or a natural occurrence. Failure to establish this type of mon ing will result in faulty management and regulation of the ecosystem.[9]

In (.er to effectively utilize the volume of baseline ecological data now in hand, perhaps an equally important expenditure of funds and effort might be directed toward analyzing and synthesizing the data into a form adaptable to the decision-making process. An indication that this need is recognized to some extent comes from examination of the budget of the Federal Plan for Marine Environmental Prediction for the fiscal years 1974 and 1975.[10] Federal agencies budgeted $101 million in FY 74 for data acquisition and processing, and nearly $112 million in FY 75. During the same period the funds budgeted for information dissemination and understanding basic processes increased from $88 million to $116 million.

The problem of interpreting basic environmental information and evaluating its significance with regard to a particular issue is one of the most difficult and important aspects of environmental impact prediction. While it is easy to couch potential impacts and effects in terms of what may occur, it is almost impossible to state what will occur if a particular action is taken. In order to state what will occur, the probability of the occurrence must be determined. The usual means of calculating the probability of an event occurring is to rely on data of past occurrences. The validity of a probability calculation depends on the validity of the assumptions made and the data that enter into the calculation. Before examining statistics of past OCS pollution events, a more complete background could be provided by an examination of some factors that influence the extent of the ecological impact and a review of recent improvements in exploration and production technology.

FATE OF PETROLEUM IN THE MARINE ENVIRONMENT

When petroleum is spilled into the ocean it immediately begins to undergo changes at a rate determined by the composition of the petroleum and characteristics of the environment such as temperature, concentration of bacteria and nutrients, and sea state. These changes occur through evaporation, solution, spreading, emulsification, air-sea interchange, oxidation, biological degradation and uptake, and sedimentation. Petroleum spilled offshore forms slicks and tar lumps but these are transient conditions. The ultimate fate of most spills in the ocean is a combination of evaporation and decomposition in the atmosphere, plus oxidation to carbon dioxide by chemical or biological means. The rest is dispersed in the water column or incorporated into sediments. The more volatile and soluble compounds, representing

[9] St. Amant, op. cit., p. 6–7.
[10] Interagency Committee for Marine Environmental Prediction. Federal Plan for Marine Environmental Prediction. Washington, D.C., 1974. 22 p.

approximately 80 percent of the spill volume, disperse within a few weeks. The heavier fraction of petroleum forms tar lumps which are estimated to have a residence time in the ocean of about a year.[11] Tar stranded on rocky shores may have a much longer lifetime. Oil that becomes incorporated in coastal sands protected from the weathering effects of sun and oxygen may have a residence time measured in years or decades.[12]

Microorganisms consume and oxidize the least toxic components of petroleum (normal alkanes) in a few days or months, depending on temperature and nutrient supply. The more toxic constituents (aromatics and naphthenes) are degraded more slowly. Larger organisms take up hydrocarbons through the gills or by ingestion of particulate matter. Fish and lobsters have been shown to metabolize most petroleum hydrocarbons within two weeks but metabolism in plankton and bottom dwelling invertebrates is slower and the pathways are poorly understood. There is no evidence for biological magnification of petroleum hydrocarbons through the food chain. Except in special cases, direct uptake of petroleum hydrocarbons from the water or sediments appears to be more important than uptake from the food chain.

There is little question that most marine organisms exposed to petroleum hydrocarbons incorporate them into their tissues. However, there are two schools of thought about the ability of marine organisms to rid themselves of hydrocarbons once they have become contaminated. One school subscribes to the hypothesis that organisms retain incorporated hydrocarbons indefinitely when the source of pollution is removed, and undergo little, if any, self cleansing.[13] The other school of thought contends that organisms rid their tissues of hydrocarbons when they are exposed to clean water.[14] In reconciling these two views, the length of exposure may be the critical factor. Organisms that have adapted to conditions of hydrocarbon pollution over several weeks or months appear to undergo slow or limited depuration in clean water. However, organisms that have been exposed to oil in water for periods up to two weeks are able to rid themselves of most petroleum hydrocarbon accumulation in a few days.[15] [16]

FACTORS THAT DETERMINE THE SEVERITY OF THE ECOLOGICAL IMPACT

Every oil spill will not have the same impact on the environment. Some spills may have a relatively minor effect compared to others which may be much more locally damaging. Several factors influence the extent of the ecological impact. Among the more important of these factors are:

1. The dosage of oil an ecosystem receives;
2. The physical and chemical nature of the oil spilled, including the effects of weathering;

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[11] Butler, J. N. "Pelagic Tar." Scientific American. June 1975, p. 90–97.
[12] National Academy of Sciences, 1975, op. cit., p. 105.
[13] Blumer, M., J. Sass, G. Souza, H. Sanders, F. Grassele, and G. Hampson. "The West Falmouth Oil Spill." Woods Hole Oceanographic Institution, Ref. No. 70–44, 1970, 32 p.
[14] Anderson, J. W. (ed.) "Laboratory Studies on the Effects of Oil on Marine Organisms: An Overview." American Petroleum Institute Publication No. 4249, 1975, 70 p.
[15] Dames and Moore. "Critique of the Bureau of Land Management's Draft Environmental Statement for Lease Sale 35." In Final Environmental Statement OCS Sale 35, Southern California, v. III, 1975, p. 578–748.
[16] Vaughan, B. E. (ed.) "Effects of Oil and Chemically Dispersed Oil on Selected Marine Biota—A Laboratory Study." American Petroleum Institute Publication No. 4191, 1973, various pagination.

3. The climatic conditions and location where the spill occurs;
4. The time of year of the spill;
5. The prevailing oceanographic and meteorological conditions; and
6. The techniques used to clean up the spill.

The dosage of oil an area receives depends primarily on the size of the spill and the elapsed time before it is dispersed. Physical constrictions on the spill, such as embayments, keep the oil concentrated in a small area where the effects will be greater than in the open ocean. The portions of the oil that sink, float, and dissolve also determine the dosage. For example, a bottom dwelling organism will be primarily affected by sunken or dissolved oil, whereas most estimates of dosages are made on the basis of visible floating oil.

Since crude oil is a mixture of thousands of compounds, mostly hydrocarbons, and each source of crude oil is different, the physical and chemical nature of the crude spilled partly determines the ecological impact. All crude oils contain three general classes of hydrocarbons: alkanes, cycloalkanes, and aromatic. An "average" crude oil has the following approximate composition:

A. By molecular type

	Percent
Paraffin hydrocarbons (alkanes)	30
Naphthene hydrocarbons (cycloalkanes)	50
Aromatic hydrocarbons	15
Nitrogen, sulfur, and oxygen-containing compounds (NSOs)	5

B. By molecular size (number of carbon atoms per molecule)

	Percent
Gasoline (5 to 10)	30
Kerosene (10 to 12)	10
Light distillate oil (12 to 20)	15
Heavy distillate oil (20 to 40)	25
Residual oil (more than 40)	20

Crudes from different sources can vary greatly from these average compositions. For example, an average Venezuelan crude can run 45 percent naphthenes, 25 percent aromatics and 20 percent NSOs whereas a south Texas crude would be shifted to the paraffin-naphthene end. One study of the toxicities of 20 different oils showed that the susceptibility of a particular snail varied significantly according to which of the oils it was exposed.[17]

While OCS production would primarily involve crude oil not refined products, the differences between crude and refined products are worth noting. Generally, refined products such as fuel oil or gasoline have greater concentrations of toxic components than crude oils and spills of refined products would likely have a greater ecological impact. This has been cited as one reason for the severity of the observed effects of the West Falmouth spill. On the other hand, studies of a large fuel oil spill (54,000 bbl) in Japan's Inland Sea in December 1974 recently indicated no evidence of lasting damage.[18] The Inland Sea seemed particularly vulnerable to contamination

[17] Ottway, S. M. "The Comparative Toxicities of Crude Oils." In Proceedings, Symposium on the Ecological Effects of Oil Pollution on Littoral Communities, Cowell, E. B. (ed.), Institute of Petroleum, London, 1970.

[18] Chemical and Engineering News. "No Lasting Damage From Japanese Oil Spill," Oct. 20, 1975, p. 13.

because it is relatively shallow and circulation is restricted. Furthermore, it is a prized fishing, seaweed cultivation, and recreation area. Long term studies are continuing, but data indicate population levels of marine organisms and water quality returned to normal levels after three months.

Weathering is important because the longer the spill is exposed before it enters a particular area, the fewer harmful compounds it will contain. Generally the lighter and more soluble compounds which are the more toxic are removed and degraded early in the weathering process. Heavy tarry residues have much less severe biological impact.

The climatic conditions and location of the spill area influence the ecological impact. The effects of oil spilled in a cold marine environment, such as the North American arctic, might be much more serious and long lasting than in more temperate areas for the following reasons:

1. cold temperatures do not permit rapid evaporation of aromatics in oil, thus allowing more of these toxic hydrocarbons to enter solution in sea water even though the solubility of these compounds is lower at low temperatures;
2. the rate of bacterial degradation and other processes of weathering are comparatively slower at very cold temperatures; and
3. the marine biota of polar regions are generally long-lived, have low reproductive potentials and do not have wide ranging dispersal stages.[19]

For these reasons, recovery from oil spills in polar regions would be slow.

Another reason that the location of a spill is an important factor in determining the impact is that biota vary greatly from area to area. For example, the habitat of the east coast of the United States is geologically and ecologically quite different from the west coast, and the Louisiana coastal environment is not like that of Maine. Different biota are affected differently. A study of the Santa Barbara spill showed that one type of barnacle was able to resettle earlier than another because it is larger and had a base plate that protected it from the oil encrusted substrate.[20]

The season of the year a spill occurs is an important factor. Most marine organisms show natural seasonal variations that are related to yearly cycles, as well as year to year variations. For example, if a spill occurs during the winter in an area where seabirds are nesting, the bird mortality would be much higher than at some other time of the year. If a spill enters an estuary when salmon fry are going to sea or during a salmon run, a much higher kill is likely.[21] Crab larvae, which float near the surface of the water, and newly set oyster spats will probably be killed if a spill occurs during this stage of their life cycles, whereas the damage would not likely be so great to these organisms during some other stage of development. Had the Santa Barbara spill happened earlier, nursing pups of sea lions and elephant seals may have succumbed after ingesting oil coating their mothers

[19] Boesch, et al. op. cit., p. 24.
[20] Straughan, D. "Factors Causing Environmental Changes After an Oil Spill." Journal of Petroleum Technology, March 1973, p. 250–254.
[21] National Academy of Sciences, op. cit., p. 83.

teats, and sea bird populations would have been greater[22] (likely resulting in more mortalities).

Other factors influencing the severity of the impact from a spill are the oceanographic and meteorological conditions in the spill area. Wind and currents may drive floating oil either onshore or offshore. Currents and wave action combine to spread and dilute the spilled oil, thus reducing its toxicity. On the other hand, wave action may intensify problems especially near shore, as apparently occurred at West Falmouth. At West Falmouth, onshore winds churned oil with sediments and drove the oil ashore into the surrounding marshland. The oiled sediments and marshland then became a reservoir of oil for many months.[23]

At Santa Barbara, the spill occurred during a period of heavy storms that brought flood waters bearing great amounts of sediments into the coastal waters. The sediment-laden fresh water provided an adsorptive surface for the spilled oil causing much of it to settle on the bottom rather than on the shore.[24] Sedimentation is advantageous if the intertidal life is abundant, but it may be detrimental to benthic (bottom dwelling) life.[25]

An improper method of cleaning up an oil spill can increase the impact of oil pollution rather than diminish it. Mechanical methods are considered the least damaging to the environment. These methods include the use of booms and skimmers or the spreading and retrieval of absorbent material. Sinking agents acting in the same way as naturally turbid water, transfer the effects from intertidal coastal areas to offshore bottom-dwelling fauna, and may extend the duration of the impact. The use of dispersants is controversial and has been shown to be helpful in some cases and harmful in others, depending on the toxicity of the dispersant and the particular organisms one is intending to protect. Low-toxicity dispersants have the advantage of preventing oil from washing ashore and killing intertidal organisms, but pose an additional burden on the assimilative capacity of the marine environment. Cleanup technology will be discussed more fully in another section.

IMPACTS OF DRILLING

One of the most hazardous steps in offshore oil and gas development is exploratory drilling. The hazard potential is greatest when drilling into an unknown formation because of the possibility of encountering an unexpected sudden surge of pressure up the drill hole causing a blowout or loss of well control. Most blowouts involve only gas which is less environmentally damaging than if oil is released. An analysis of major OCS accidents by the University of Oklahoma Technology Assessment Group found that out of a total of 19 blowouts that occurred during drilling through the years 1953–1972, 17 involved gas only and 2 involved both oil and gas.[26] The Santa Barbara blowout was one of

[22] Boesch, et al. op. cit., p. 38.

[23] Blumer, M., H. L. Sanders, J. F. Grassle, and G. R. Hampson. "A Small Oil Spill." Environment, vol. 13, no. 2, 1971, p. 1–12.

[24] Drake, D. E., P. Fleischer and R. L. Kolpack. Transport and Deposition of Flood Sediment, Santa Barbara Channel, California. In: Biological and Oceanographical Survey of the Santa Barbara Channel Oil Spill 1969–1970. Vol. 2 R. L. Kolpack, ed., Allan Hancock Foundation, 1971, p. 181–217.

[25] Blumer et al., 1971, op. cit., p. 1–12.

[26] Kash, D. E., et al. "Energy Under the Oceans." University of Oklahoma, Science and Public Policy Program, Technology Assessment Group, Norman, 1973, 378 p.

the latter. If the oil and gas becomes ignited, the environmental damage may be reduced, such as the Bay Marchand fire of Dec. 1970, but it is more difficult to bring the well under control. While blowouts, especially those invoving oil, have a severe environmental impact they are generally of short duration which aids recovery of the ecosystem. Furthermore, based on the number of wells drilled, blowouts are very unlikely to occur (see section on probabilities of oil spills and blowouts).

Unavoidable impacts from routine exploratory drilling operations include discharge of drilling mud and cuttings into the ocean. As the drill bit cuts through bottom strata, bits of rock and drilling mud are circulated to the surface where they are cleaned and discharged into the ocean. Most drilling mud is recovered and reused but some is lost. Cuttings consist of the same materials as the bottom sediments and are not considered toxic. Drilling muds can contain toxic components which could produce harmful results if allowed to reach high enough local concentrations. Barium is a major component of drilling muds. However, *soluble* barium in drilling mud is present in approximately the same concentration as found in seawater.[27] Analyses of chrome lignosulfonate drilling mud from a platform off the Louisiana coast show soluble chromium levels of less than 0.2 ppm.[28] By comparison waste water discharges off Southern California average about 0.3 ppm. chromium.[29]

While the impacts of discharged drilling muds are not fully understood, considering the dilution effect of low rate of discharge relative to the depth of the ocean water column, significant harmful impacts are unlikely to occur. Smothering of a few organisms in the immediate vicinity of the rig would likely result, but this impact is insignificant compared to smothering of organisms due to natural shifts of sediments from storms, currents, etc. On the other hand, experience in California has shown that communities of bottom dwelling organisms have established in the discharged cuttings and muds in areas where no communities existed before.[30] The total weight of cuttings and mud discharged is about 1,200 tons per well.

IMPACTS DURING PRODUCTION AND DEVELOPMENT

Severe impacts can occur from oil spilled from offshore operations at any time, but the most likely time for a spill to occur (other than a blowout) is during production and field development. During this stage oil is being removed from the reservoir through the wells to a storage or transmission facility. Once oil is removed from the ground and until it is ultimately consumed, there are several transfer steps and, consequently, a possibility that spillage will occur. In offshore operations most transfer steps occur during the production and development state in producing, collecting and transporting the oil ashore.

Other than spillage from normal operations, production platforms are subject to damage from natural forces. Any severe damage to a

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[27] Dames and Moore, op. cit., p. 9.
[28] Ibid., p. 10.
[29] Young, D. R. and T. Jan. "Chromium in Municipal Wastewater and Seawater." In Southern California Coastal Water Research Project Annual Report 1975. El Segundo, California, pp. 147–149.
[30] Goodman, J. "Decisions for Delaware: Sea Grant Looks at OCS Development." Univ. of Delaware, 1975, p. 31.

production platform could release oil into the marine environment if the wells were not shut down by subsurface valves. Platforms are designed to withstand greater wind and wave conditions than they might be expected to encounter. Severe storms would not seriously affect operations as the wells can be shut down and the platform abandoned if necessary. Even in hurricane force waves few platforms have foundered (of more than 3000 platforms less than one percent had foundered through 1972).[31] Production platforms are expensive especially for deep water and, consequently, to be economically attractive production rates have to be high. New platforms are designed to accommodate 20 to 25 wells with 40 well platforms being planned. More wells per platform will permit fewer platforms and reduce the opportunities for severe platform damage. All new OCS wells are required to have surface activated subsurface valves. Subsurface completion systems can be used to avoid many of the hazards of severe storms and other hazards such as ice problems in the arctic.

Ice can be a problem for both exploration rigs and production platforms. Moving pack ice is a serious hazard in the Alaskan Arctic. Ice accumulating on the surface of a structure increases its weight and presents safety hazards. Special equipment is being designed to counter these problems. For example, General Dynamics has designed a moored drilling system that includes a cone-shaped hull that is forced upwards by ice pressure until the weight of the hull breaks the ice. The system could operate in up to 660 feet of water and fast ice up to 5 feet thick. Global Marine is working on an ice breaking drill ship that uses a Pneumatically Induced Pitching System (PIPS) to break ice. The "monopod" platform used in Cook Inlet is a type of caisson structure specially designed to resist forces exerted by migrating ice sheets.

Earthquakes present another potential hazard to offshore production operations. However, experience to date has indicated that industry has been able to meet this challenge. One of the severest tests came in 1964 when a quake of 8.3 to 8.75 on the Richter scale occurred near the Cook Inlet petroleum fields. The earthquake resulted in ground vibration and rupture, landslides, differential settlement, liquefaction of sediments, submarine mudflows and rock slides, and seismic sea waves. However there was no damage to the petroleum and gas operations in Cook Inlet. Today even more technologically advanced equipment is available to mitigate potential earthquake hazards. For example, a 940-foot platform has been designed for installation in the Santa Barbara Channel that is being built to withstand the maximum earthquakes likely in that area.

Unavoidable pollution from offshore production results from discharge of formation water containing traces of oil into the ocean. A normal oil bearing formation usually contains water. In addition, water is commonly used to flush more oil out than might otherwise be recovered. Water may represent 20 to 30 percent of the extracted fluid of a well in the initial stages of development and increases to more than 50 percent as the oil reservoir is depleted. An oil-water separater located on the platform is used to reduce the oil in the discharged water to very low levels. Recently, the Environmental Protection Agency

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[31] National Academy of Engineering, Marine Board, "Outer Continental Shelf Resource Development Safety," December, 1972, p. 26.

(EPA) announced the successful testing of an improved separator that reduces the oil in the effluent water to less than 10 ppm (parts per million).[32] This separator developed by Pollution Abatement Research, Inc. under contract to EPA is impressively described as a "backflushable coalescer and solids scrubber." While there is no evidence to date that low level oil release from offshore production causes any significant environmental impact, the possibility exists that long term effects could show up. One problem in this regard is that the more soluble fractions of petroleum are generally the most biologically harmful. In any event, it is desirable that the oil released be kept to the lowest level possible. Sand produced with the oil may also be discharged into the ocean after the oil is removed.

Formation water also contains dissolved solids somewhat similar to concentrated seawater (petroleum is believed to be formed in buried near shore and marine deposits and formation water would likely derive from ancient seawater). Discharge of these brines into the ocean apparently does not cause a significant impact. Formation water can, if necessary or economically feasible, be transported to shore for treatment. Of 605,000 bbl of formation water produced daily offshore from Louisiana OCS operations, 305,000 bbl are transported to shore for treatment before release.

IMPACTS FROM TRANSPORTATION

When oil is produced the first step is to gather a sufficient volume from adjacent areas to economically transport it to shore or ship it elsewhere. Pipelines are usually used in gathering systems however small tankers and barges moored to platforms are alternative methods. Tankers may also be used for transporting oil during the early phases of field development especially in areas distant from established producing fields. For example, production began in the North Sea Auk and Ekofisk Fields using tankers to bring the oil ashore while pipelines are still under construction.

Statistically, tankers and tank barges contribute more to oil pollution of U.S. waters than any other single source with the possible exception of sewage effluent. The U.S. Coast Guard report, Polluting Incidents In and Around U.S. Waters; Calendar Year 1973, lists 1,543 polluting incidents involving 6,066,313 gallons or 25 percent of the total volume spilled came from tank ships and tank barges.[33] Pipelines were responsible for 559 polluting incidents involving 1,847,498 gallons or 7.6 percent of the total volume spilled.

Both tankers and pipelines are subject to natural hazards which could contribute to oil spills, however, human error is generally considered the greatest single factor behind most spill events. Ice is one of the major hazards in the arctic and subarctic regions of Alaska where most undiscovered resources are expected to be found. Near shore pipelines would have to be constructed to avoid ice pressure which can greatly exceed the strength of the pipe. Tankers such as the *Manhattan* may be designed for limited operations in ice bound

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[32] Freestone, F. J. and R. B. Tabakin. "Review of U.S. Environmental Protection Agency Research in Oil-Water Separation Technology." In 1975 Conference on Prevention and Control of Oil Pollution. American Petroleum Institute. Washington, 1975, pp. 437–441.

[33] U.S. Coast Guard. "Polluting Incidents In and Around U.S. Waters: Calendar Year 1973." 11 p.

waters but even the largest icebreakers cannot operate north of the Arctic Circle during the winter and spring. Submarine tankers have been considered but studies have indicated they are not likely to be cost effective.

Severe storms would have a greater effect on tanker operations than pipelines. Pipelines can be buried to prevent rupture from anchor dragging and other causes. Burial of pipelines is now required in water depths of 200 feet or less. Detailed geologic studies would be necessary where pipelines may cross fault zones or regions of poor sediment stability.

BLOWOUT AND SPILL PREVENTION TECHNOLOGY

Blowouts are an especially visible and dramatic type of accident and have been a major influence on public opinion regarding the safety and environmental hazard of drilling on the OCS. The largest spill in the history of OCS operations in the United States was the blowout in the Santa Barbara Channel in 1969. This spill aroused a great amount of public concern and as a result lead to stricter enforcement of safety regulations for drilling on the OCS and greater emphasis on developing technology to prevent blowouts and other spills. While safety procedures and technological improvements are tending to reduce the likelihood of a blowout occurring, the current tendency of drilling in areas of more hazardous conditions and deeper water is increasing the need for further improvements.

A number of safety procedures and devices are used to minimize the risks of a blowout or pollution from the drilling and operation of oil wells. One of the most basic procedures is the use of drilling mud.

Drilling Mud

Drilling mud is a carefully formulated clay material whose weight and consistency are individually tailored to the formation pressure and geochemical environment through which the well must penetrate. While the primary purpose of drilling mud is to remove rock chips cut by the drill bit and lubricate the drill bit and string, it serves the important secondary function of balancing the underground pressure to prevent squeezing or caving of the formations and as a defense against blowouts. The typical composition of a lignosulfonate mud of 10.5 lbs. per gallon is as follows:

Mud material and weight per Barrel

	Pounds
Bentonite clay	10–12
Barium sulfate (barite)	120
Sodium hydroxide (caustic)	1
Sodium lignosulfonate	6–8
Organic polymer	0.5–1
Defoaming agent	0.1–0.25
Water	[1] 85

[1] Percent.

Barite is used as a weighting agent to control formation pressures while drilling in the lower portions of the hole. Lignosulfonates are thinners used in a mud system to control viscosity, gel strength, and filtrate loss. The mud must be kept heavy enough to contain pressures encountered during drilling, but not so heavy that it might seal off smaller potentially productive zones by penetrating the strata. In addition, drilling mud is expensive and the heavier it is the more expensive it becomes. Consequently, it is very important to control the properties of the mud. A great amount of experience is required to decide what is needed at a given time, and determining optimal mud properties is something of an art. Service companies usually provide the specialized expertise in handling muds.

Any sudden loss of mud, increase in downhole pressure, or sudden increase in drilling rate is an indication of danger. Equipment is now available for measuring the gain or loss of one barrel of mud which is generally considered accurate enough to warn of a potentially dangerous kick. When a potential blowout is indicated (Fig. 12), the first response normally is to apply some combination of increased pumping rate and the addition of heavier mud. Unexpected penetration into high-pressure zones can cause blowouts because of the difficulty of increasing the weight of the mud column rapidly enough to compensate for the increased pressure. For this reason, drilling wildcat wells into unknown geological formations can be particularly hazardous.

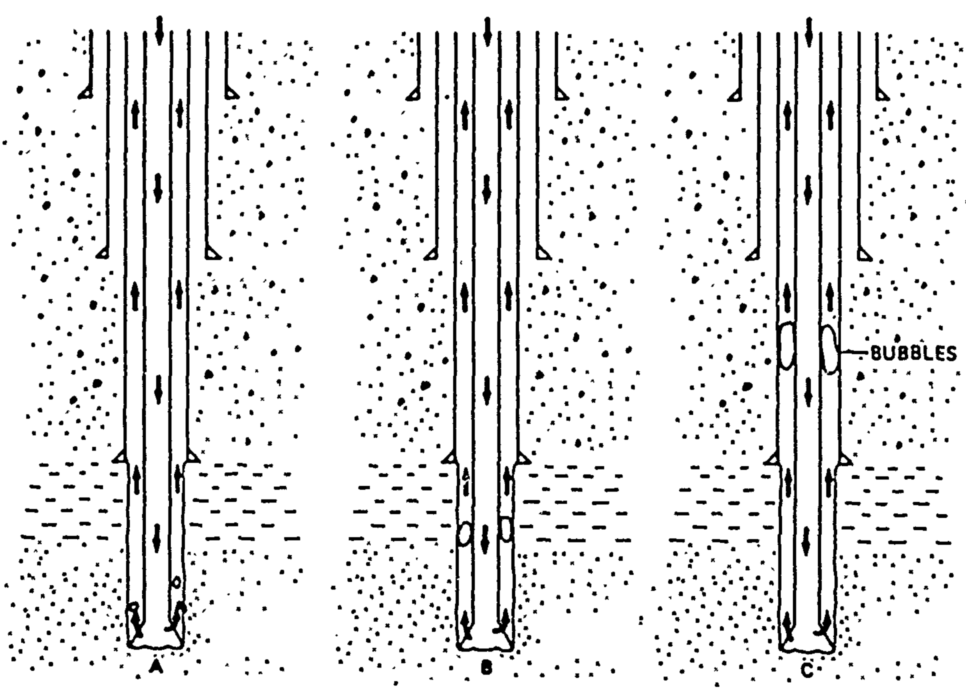


FIGURE 12.—A "kick" is a gas or liquid influx that reduces the hydrostatic head in the annulus. Here, the kick is a gas bubble (A). As it rises (B and C), it expands—causing a sudden increase in the upflow of the mud. When the bubble reaches the top, the bottom-hole pressure reaches a maximum—the sum of the mud pressure and the gas pressure. This pressure maximum, if excessive, can exceed the formation fracture pressure, and lead to a blowout.

Source: National Academy of Engineering, Marine Board. Outer Continental Shelf Resource Development Safety. December, 1972, p. 18.

Mud logging equipment continuously monitors the mud system, recording mud properties, the presences of oil or gas in the system, and the lithologic properties of the formations. Pit volume indicators are used to indicate the total volume of drilling fluid in the system as a means of detecting fluid loss to the formation or an influx of formation fluid. Both audio and visual signals indicate the amount of mud in the pit. As the drill string is pulled the quantity of mud required to replace its volume is monitored from a calibrated fill-up tank. A new method of indicating gas entry into the well bore is presently being developed and tested. It involves the use of a tool in the drill string that traps a sample of drilling fluid from the bottom of the hole. A chamber is enlarged allowing the trapped gas to expand. The energy resulting from the gas expansion is reflected on a surface weight indicator.

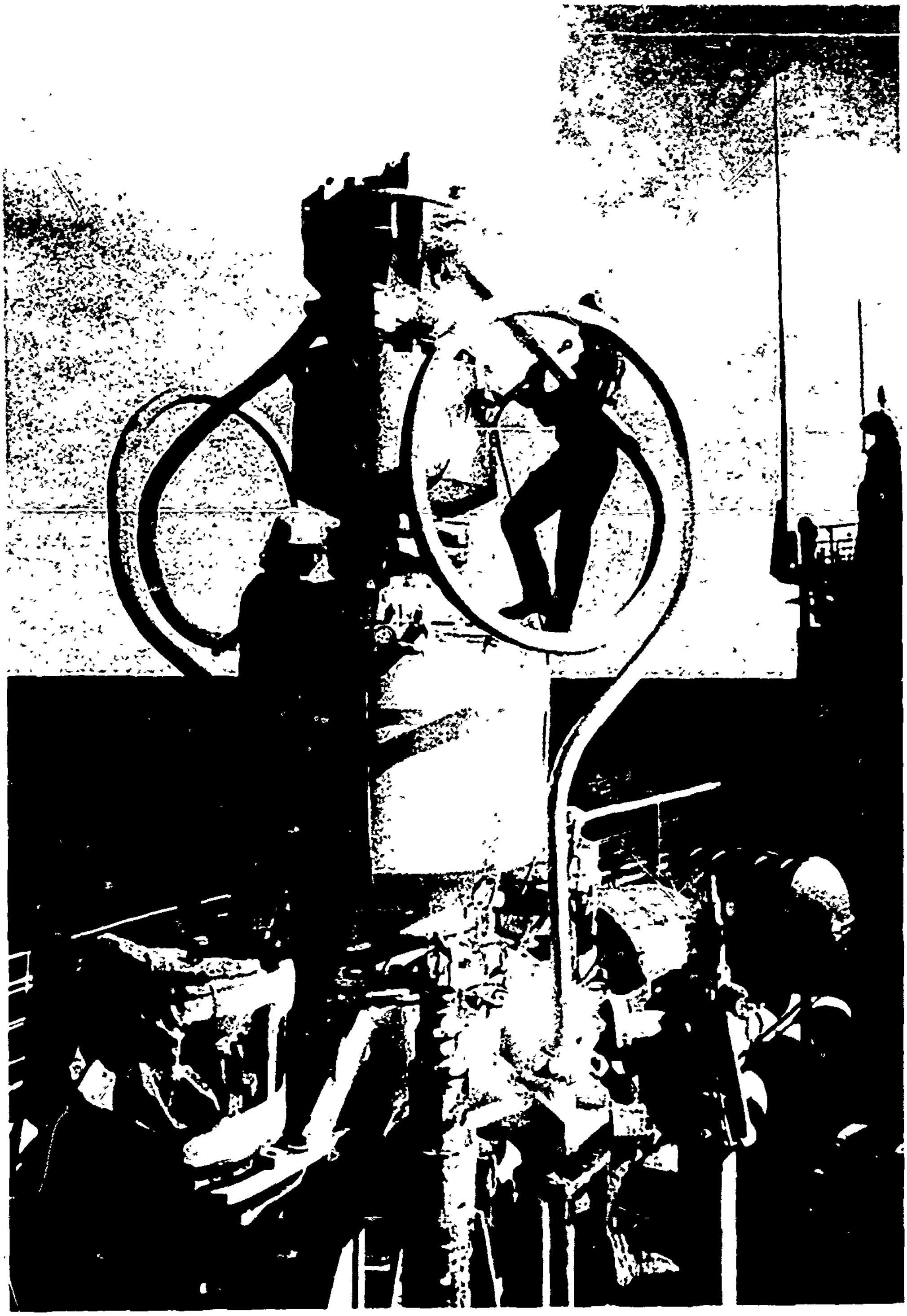
An especially vulnerable part of the drilling operation occurs during trips (moving the drill string into or out of the well bore) when loss or gain of drilling mud is more difficult to monitor. In addition to saving expensive drilling time. longer lasting bits tend to reduce the number of trips and thus the risk involved in this hazardous part of the operation. Recently, the use of newly developed multi-purpose bits on the *Glomar Challenger* have allowed much deeper penetration with a single bit.

Casing

Casings are steel pipe used to support the sides of oil wells and to provide a controlled conduit through which oil or gas are recovered. Casing also prevents contamination of potable water reservoirs and keeps water out of the producing formations. Conductor casing (the several casing strings in sequence of installation are structural, conductor, surface, intermediate, and production) is set to a minimum of 300 feet and a maximum of 500 feet and cemented along its entire length to the ocean floor. Surface casing is run down inside the conductor casing and is also cemented along its entire length. Intermediate and production casings are cemented to isolate all production zones. The purpose of cementing the casings is to provide stability and to minimize the possibility of a blowout around the outside of the drill. The casing also provides a base to which the blowout preventer (BOP) stack is mounted.

Blowout Preventers

Blowout preventers are required by law when drilling goes below the conductor casing. The BOP stack consists of a series of control valves which can be operated from two or more locations by alternate control systems through which the well is drilled. These valves are capable of either closing around the drill string to seal off the annular space or closing off the hole completely. On bottom standing platforms offshore, the BOP stack is attached to the top of the surface casing just beneath the rotary table. In the case of floating rigs, the stack is attached to the top of the surface casing on the ocean floor.



Blowout preventer on board of the Glomar Coral Sea

Courtesy Exxon Corporation.

A typical blowout preventer stack consists of three or more preventors of different types which are closed when a potential blowout is indicated. On the platform these can be closed manually, but on the sea floor the preventers are operated hydraulically or electronically.

Generally there are two pipe rams, or preventers that close around the drill pipe. If only these are activated, it is still possible for the well to blow out through the drill pipe if the kelly is not attached. Under these circumstances a preventer called a blind ram may be activated which deforms or crimps the pipe closing the hole completely. An alternative form of preventer is a shear ram, which shears off the drill pipe allowing it to drop into the hole. Since it is difficult to re-establish control of the well after loss of the drill pipe, the decision to use the blind or shear ram is not made lightly. Recently, an internal preventer has been developed to close off the space inside the drill pipe. A dough-nut-shaped bag-type preventer is also used which is somewhat less secure than the ram-type preventer, but allows the drill pipe to move with the preventer closed. The bag-type preventer is inflated with fluid to close the well, either with or without the drill pipe in it.

Blowout preventer stacks are reliable if properly maintained and operated by well trained drilling crews. Timing is important. When a potentially dangerous kick occurs either the tool pusher or the driller must take action instantly, and have the experience or sixth sense to know exactly what action is needed. When there is a sudden increase in pressure or rapid loss of drilling mud, there is little time to react to close the preventers and maintain control of the well. While the blowouts that have occurred can be documented, the number of kicks or near accidents which have been successfully brought under control without serious consequences is not known. Documentation of successful blowout prevention would be helpful in evaluating the adequacy of equipment and personnel. It is unfortunate that only the spectacular failures receive much public notice.

Surface Safety Valves

Among the safety valves and sensors on the platform designed to stop the flow of oil and gas if trouble is detected are level, pressure, and combustible gas sensors and manual, automatic, and pressure relief valves (fig. 13). When a well is completed the BOP stack is removed and a series of pipe valves and gauges called a "Christmas tree" is fitted on the top of the well. These valves can be shut either manually or remotely (if on the sea floor) to prevent or minimize pollution should the need occur, such as a pipeline rupture or other leak. Surface safety valves will also shut when any of the fusable plugs on the platform melt in the event of fire. Excessive erosion from sand carried by the oil can cause failure of piping and valves resulting in oil spillage. To counter this a sand probe or erosion detector, which will erode before serious damage occurs elsewhere, will shut a surface safety valve to prevent pollution and loss of oil. An acoustic sand detection system, which is capable of continuously monitoring and recording the flow of solids, has recently been developed.

Additional precautions during drilling include a drill string safety valve which is maintained on the derrick floor for installation on the drill pipe should there be any unexpected flow from the well. If conditions prevent the use of the safety valve which has to be screwed on the drill pipe threads, a socket type, sealed coupling can be dropped over the exposed pipe and sealed. A back-pressure valve is also kept on the derrick floor for installation after the safety valve is installed.

Additional valves are installed at the top and bottom of the kelly (a long steel forging which connects to the top joint of the drill string) to shut off flow, if necessary, while the kelly is in use.

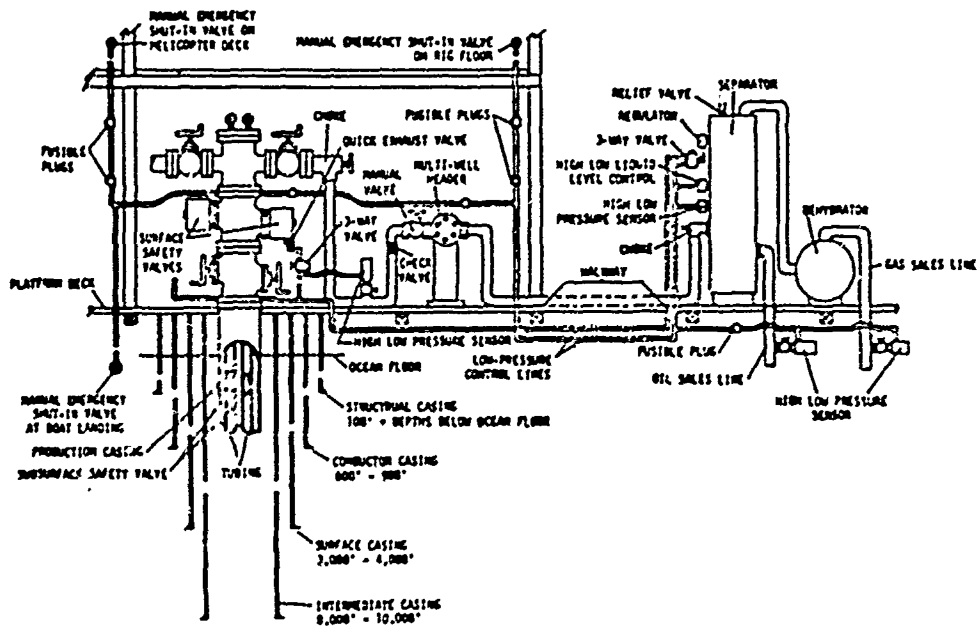
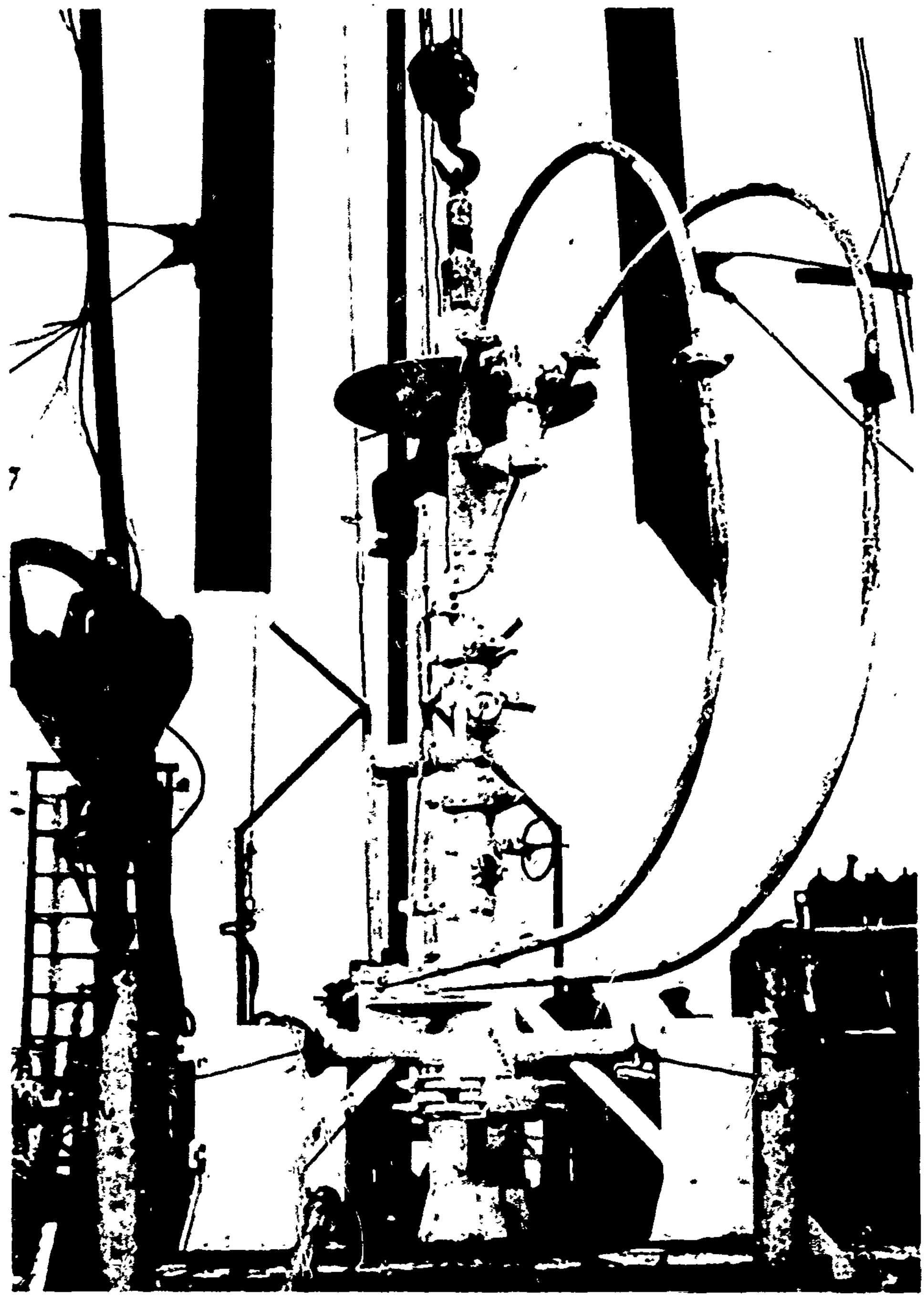


FIGURE 13.—Schematic diagram showing casing program and production safety system of a typical 12,000-foot well, Gulf of Mexico.

Source: Department of the Interior.



"Christmas Tree"

Courtesy Cameron Iron Works.

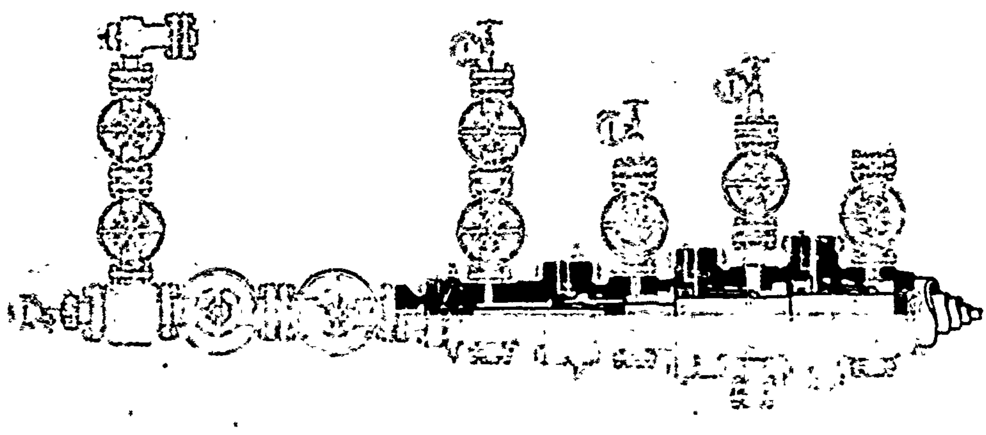


FIGURE 14.—Diagram of a "Christmas tree", a series of pipes and valves at the top of the casing of an oil well, that controls the flow of oil from the well. If after drilling the well and evaluating the productive possibilities, the operator decides to produce the well, he will run tubing, perforate, install a Christmas tree and flow line and bring the well into production. This may be done immediately after drilling is completed or the well may be temporarily capped, pending the drilling of additional wells and the installation of facilities to handle production. Regardless of whether the well was drilled with an underwater system or mudline suspension system, the operator has a choice of installing the christmas tree and flowlines on the ocean floor or of installing a suitable supporting structure, extending the well casing to the surface, and installing the tree above the water level.

Down-well Safety Values

One type of subsurface safety valve, called a storm choke, is designed to close if the oil flow rate through it exceeds some specified value. Storm chokes have been found to be especially susceptible to erosion damage. While no overall failure rate statistics are available, in 1970 and 1971 in the Gulf of Mexico 25 to 40 percent of these valves failed to shut when major accidents occurred.[34] For this reason OCS Order No. 5 (Appendix XVII) requires surface controlled subsurface safety valves to be installed 100 feet or more below the ocean floor in all wells drilled on the OCS since December 1, 1972 (with shut-in tubing pressure less than 4,000 pounds per square inch) and all new tubing installations in existing wells.[35] One remotely controlled type of valve is activated from the surface by a small hydraulic pressure line strung in the annulus between the well casing and the production tubing. A drop in hydraulic pressure, either intentional or accidental, causes the valve to close. A relatively new type of surface activated subsurface control valve, being developed by Exxon, gains improved safety protection by using two strings of production tubing, one inside the other.[36] Hydraulic pressure between the tubes activates the valve. Future subsurface safety valves will be selected on the basis of proven performance and reliability. The American Petroleum Institute has formed a subcommittee to improve standards, specifications and test-

[34] Kash et al., op. cit., p. 69.

[35] U.S. Department of the Interior. Geological Survey. Conservation Division. Gulf of Mexico Area, OCS Order No. 5, June 5, 1972; Pacific Region OCS Order No. 5, June 1, 1971.

[36] Warner, D. G. "Spill Prevention in Offshore Petroleum Producing Facilities." In Prevention and Control of Oil Spills, 1973 Conference. American Petroleum Institute, Washington, 1973, pp. 31–37.

ing procedures for downhole safety devices and has established quality control requirements and testing procedures to insure consistency in manufacturing. All surface and subsurface controlled valves must be tested at least once every six months with the exception of a minor number of very specific type valves which are tested annually.

Pipeline Spill Prevention

Although some of the largest pipeline spills have been accidents, such as breaks from anchor dragging, most pipeline spills result from failure of older pipelines. Corrosion of the external surface of the pipeline is the principal cause. Newer pipelines have epoxy coatings and cathodic protection to reduce the corrosion rate. Many new pipelines also have automatic shutdown devices to stop the oil flow if a major leak occurs.

The primary leak detection system in use is a set of automatic pressure sensing recorders on both ends of each pipeline system. The recorders are equipped with an alarm system which either shuts down the flow automatically or sounds an alarm to alert personnel of an abnormal pressure level. Leaks which decrease the line pressure greater than 300 to 500 psi are detected immediately.

A second type of leak detection system consists of volume recording flow meters on either end of a pipeline system. The flow sensors continuously monitor the net input and output and alert operators to a decrease in output representing a leak. Sensitive ultrasonic detectors are also being developed for use in locating "pinhole" leaks in offshore pipelines.

PROBABILITIES OF OIL SPILLS AND BLOWOUTS

Any major activity involving a large number of workers and heavy complex equipment is going to involve accidents. Drilling for oil and gas on the outer continental shelf is no exception. A number of accidents resulting in oil spills and injuries to workers have occurred. While every effort should be made to reduce the probability of future accidents on the OCS, there are other endeavors in the energy production field that are certainly as hazardous, if not more so, or as likely to produce environmental pollution.

OCS Oil Pollution in Perspective

Several attempts have been made to quantify the annual amount of petroleum hydrocarbons entering the oceans from various sources (Fig. 15). One recent study by the National Academy of Sciences, entitled "Petroleum in the Marine Environment," analyzed a number of previous studies and compiled estimates of the worldwide input of petroleum hydrocarbons into the oceans from all sources considered significant.[37] This study estimated the total annual input is on the order of 6 million metric tons (Table 2). Of this amount, over 2.1 million metric tons or 35 percent results from ship and tanker operations; 1.9 million metric tons (31 percent) from river and urban runoff; 0.8 million metric tons (13 percent) from coastal refineries, industrial and municipal waste; 0.6 million metric tons or 9.8 percent each from atmospheric fallout and natural seeps; and 0.08 million metric tons (1.3 percent) from offshore oil production. The relatively minor roll of OCS operations in polluting the oceans is arrived at

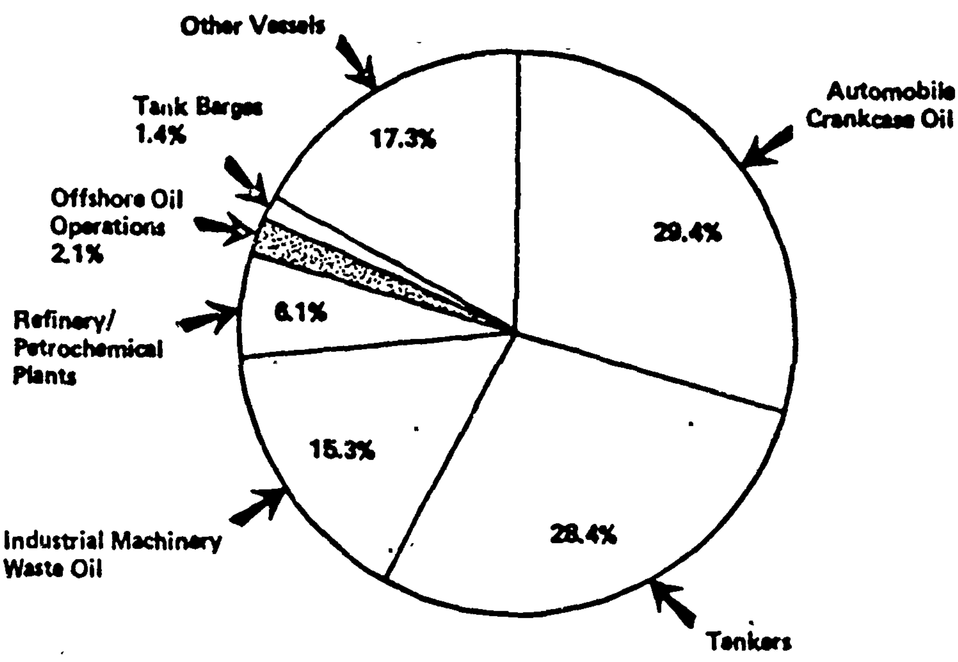
[37] National Academy of Sciences, op. cit., 107 p.

despite the assumptions that minor spills (50 barrels or less) from OCS operations elsewhere in the world would probably be ten times greater than occur in the United States and that the oil content of discharged brines would be four times greater elsewhere. Major accidents were considered equally probable worldwide as in the United States.

FIGURE 15

Sources of Ocean Oil Pollution, 1972

TOTAL: 37 Million Barrels



Source: Porricelli, J.D., and Keith, V.F., *Tankers and U.S. Energy Situation—an Economic and Environmental Analysis*, 1973, page 063.

TABLE 2.—BUDGET OF PETROLEUM HYDROCARBONS INTRODUCED INTO THE OCEANS

Source	Input (millions of tons per year)	
	Best estimate	Probable range
Offshore production	0.08	0.08–0.15
LOT tankers	.31	.15–.4
Non-LOT tankers	.77	.65–1.0
Drydocking	.25	.2–.3
Terminal operations	.003	.0015–.005
Bilges bunkering	.5	.4–.7
Tanker accidents	.2	.12–.25
Nontanker accidents	.1	.02–.15
Transportation total	2,133	

TABLE 2.—BUDGET OF PETROLEUM HYDROCARBONS INTRODUCED INTO THE OCEANS—Continued

Source	Input (millions of tons per year) Best estimate	Probable range
Coastal refineries	.2	.2–.3
Coastal municipal wastes	.3	
Coastal, nonrefining, industrial wastes	.3	
Urban runoff	.3	.1–.5
River runoff	1.6	
Atmosphere through vaporization of petroleum products	.6	.4–.8
Total through man's activities	5.513	
Natural seeps	.6	.1–1.0
Total annual petroleum input	6.113	
Comparisons:		
World oil production (1973)		2,890
Oil Transport by tanker (1973)		1,695
Torrey Canyon discharge		0.117
Santa Barbara blowout		.003–.011
Hydrocarbons produced by marine organisms		10

Source: Adopted from National Academy of Sciences, Petroleum in the Marine Environment, Washington, D.C., 1975 p. 6, and other sources.

Oil spills from ship and tanker operations cause about 27 times as much petroleum input into the oceans as do offshore operations. Total world oil production in 1973 was approximately 2,890 million metric tons, of which approximately 1,695 million metric tons was transported by sea. This vast amount of petroleum transported by tankers is a much greater threat to the marine environment than oil and gas operations on the outer continental shelf. The other great source of oil pollution of the marine environment, river and urban runoff, is primarily the result of loss and improper disposal of waste oil. This source produces approximately 24 times the amount of oil pollution as offshore operations. A 10 percent reduction in the amount of waste oil entering the oceans would eliminate more than twice as much oil as is spilled from all offshore production.

Ship and tanker operations together with river and urban runoff account for essentially two-thirds of the petroleum hydrocarbons entering the marine environment. Not to belittle the importance of dealing with all other sources, but stronger efforts in amending these two problems in particular would have the most significance in protecting the oceans from oil pollution. This consideration is especially relevant if a decision not to develop an area having a favorable potential for oil and gas were to be based primarily on the need not to stress an already polluted environment beyond its ability to recover. Partial removal of one or more of the other sources of pollution in order to produce oil and gas offshore might be environmentally acceptable.

Oil Pollution in U.S. Waters

The U.S. Coast Guard through its Marine Environmental Protection program keeps data files on polluting incidents in U.S. waters. The files have been kept since 1970 and are summarized annually in reports for the calendar year. These annual reports indicate that while wide variation in both the location number of spills, and volume spilled exists from year to year, some trends are discernable. Most oil spill incidents in U.S. waters take place in areas of high population density and shipping activity. Tanker and tank barge spills are more numerous and contribute much more to the total volume spilled than do either offshore production or pipeline transport. More oil is spilled along the Atlantic coast where there is no offshore petroleum production than is spilled in the Gulf of Mexico. Most of this spillage can be attributed to tanker operations. The Coast Guard data do not include most waste oil discharge which reaches coastal waters through runoff and sewer effluent. Only specific spill events are reported.

Statistical analysis of oil spill data for offshore operations require some interpretation because of the characteristics of oil spills. For one thing, the size range of individual spills is extremely large, from a fraction of a barrel to over 150,000 barrels. Most oil spills are small; in 1972, 96 percent were less than 24 barrels (1,000 gallons) and 85 percent were less than 2.4 barrels (100 gallons). A few very large spills account for most of the oil spilled. For example, in 1970 and 1972 three spills each year accounted for two-thirds of all oil spilled in the United States in those years. Another characteristic of spills is that the fluctuations from year to year are quite large. For these reasons, estimates of the average amount spilled from a particular cause are almost meaningless. The amount spilled from any source can vary by a factor of 1 million. One spill such as the Santa Barbara Channel spill can completely distort the size distribution of spill magnitudes. Average spill rates can also be distorted, hence projections based on these are suspect. Finally, analyses of data of past spills, unless factored in some way to account for new and future improvement in technology and operator training, will not accurately project future spill probabilities. On the other hand, new and frontier areas of the OCS present environmental hazards such as climatic conditions or water depths for which new technology has not yet been tested. One study by the University of Oklahoma suggested these last two considerations may cancel each other out.[38] Despite the problems mentioned, some statements can be made concerning the probability of oil pollution from specific causes related to offshore oil and gas development.

A number of methods have been developed to express oil spill probabilities. One method utilizing sophisticated statistical techniques was developed at Massachusetts Institute of Technology (MIT) for the Council on Environmental Quality.[39] The MIT group determined that because of the extremely large size range of individual spills, estimates of spillage and spill rates have little meaning. For this reason, the MIT report focused its analysis on the frequency and magnitudes of OCS oil spills through 1972 in order to develop probability estimates of the number of spills of a given type which will occur from a given hypothetical development, such as a small or large field, and the probability distribution of the size of these spills (Figures 16 through 19). The MIT report analyzed spills in three categories, offshore pipeline, platform, and tanker/barge.

With regard to tanker spills, the MIT results indicate that if tankers are used to transport oil ashore from a small find (500 MM bbls in place) there is a 70 percent likelihood of no tanker spills, a 25 percent probability of one spill, and more than one spill over 1,000 barrels is very unlikely. However, for a large find (10,000 MM bbls in place) there is a high probability of somewhere between 4 to 10 large tanker spills. Small tanker spills (less than 1,000 bbls) would likely number in the hundreds for a small field and in the thousands for a large field. Most of these spills would be very small.

[38] Kash et al. op. cit., p. 117.

[39] Devanney, J. W. III, and R. J. Stewart. "Analysis of Oil Spill Statistics." In Primary Physical Impacts of Offshore Petroleum Developments, Report to Council on Environmental Quality, Report No. MITSG 74-20, 1974, 126 p.

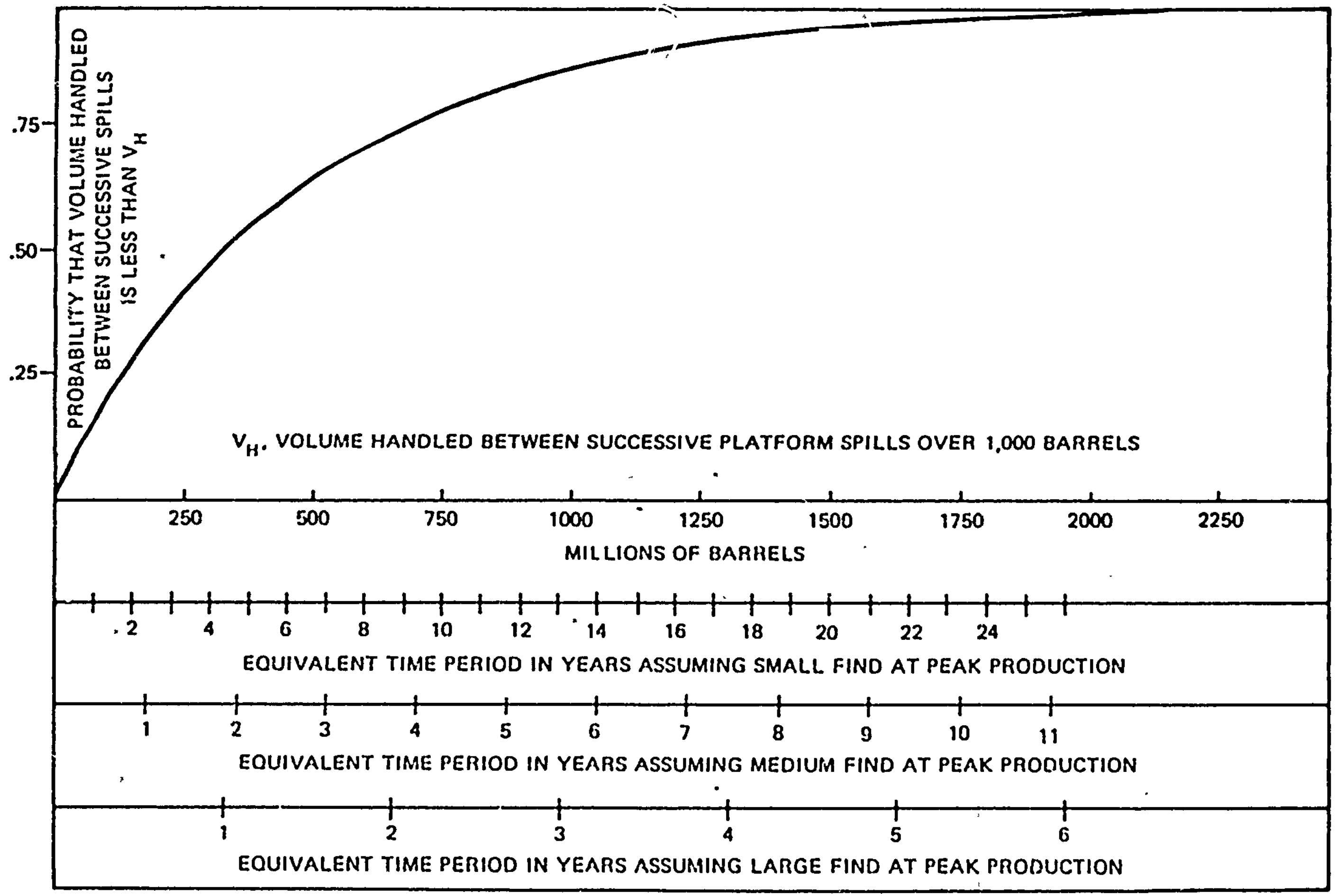


FIGURE 16.—Cumulative Volume of Oil Handled Between Platform Spills Larger than 1,000 Barrels.

Source: Massachusetts Institute of Technology, "Oil Spill Trajectory Studies for Atlantic Coast and Gulf of Alaska," *Primary Physical Impacts of Offshore Petroleum Developments*, prepared for the Council on Environmental Quality under contract No. EQC330 (Cambridge: Massachusetts Institute of Technology, 1974), Report No. MITSG 74-20.

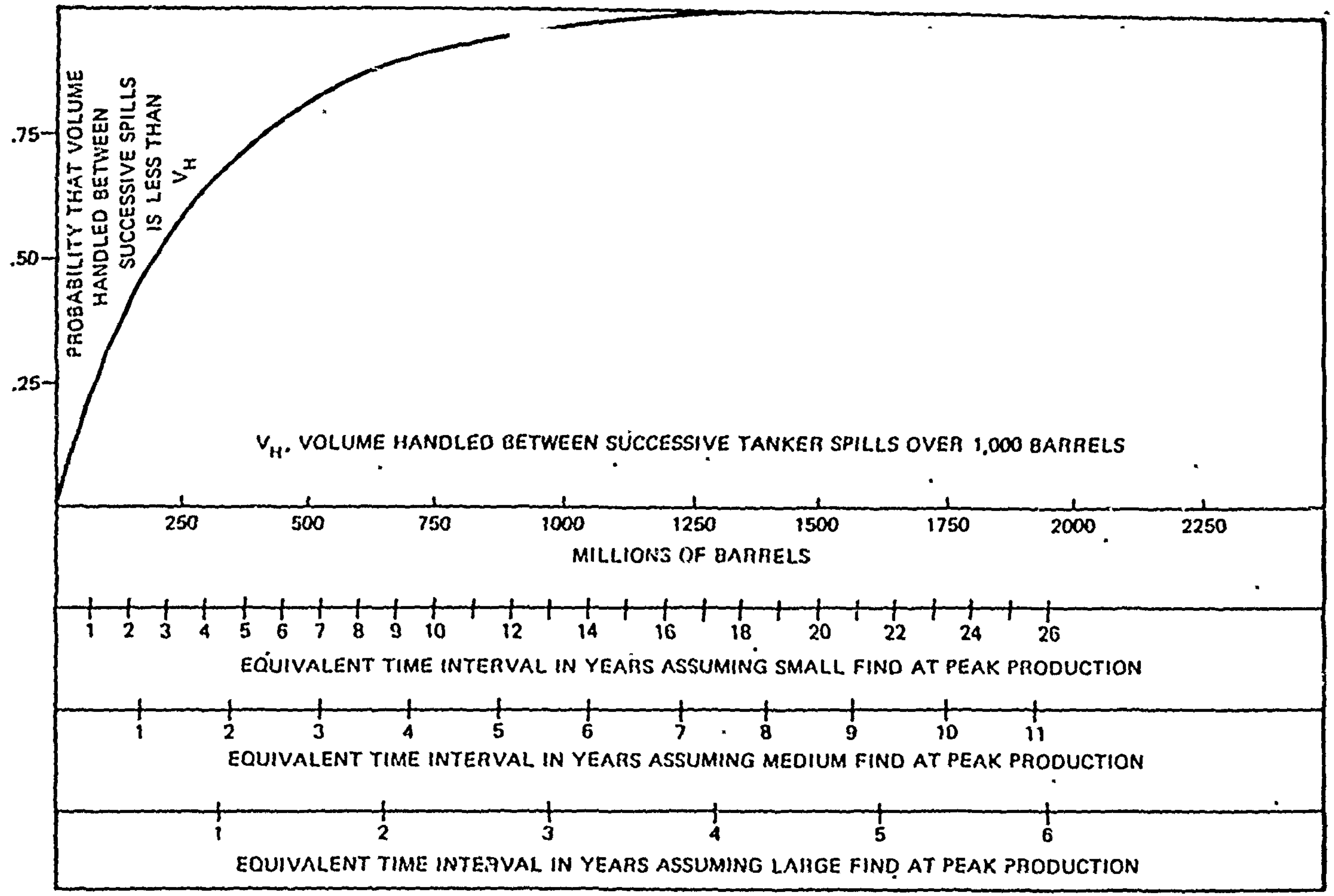


FIGURE 17.—Cumulative Volume of Oil Handled Between Tanker Spills Larger than 1,000 Barrels.

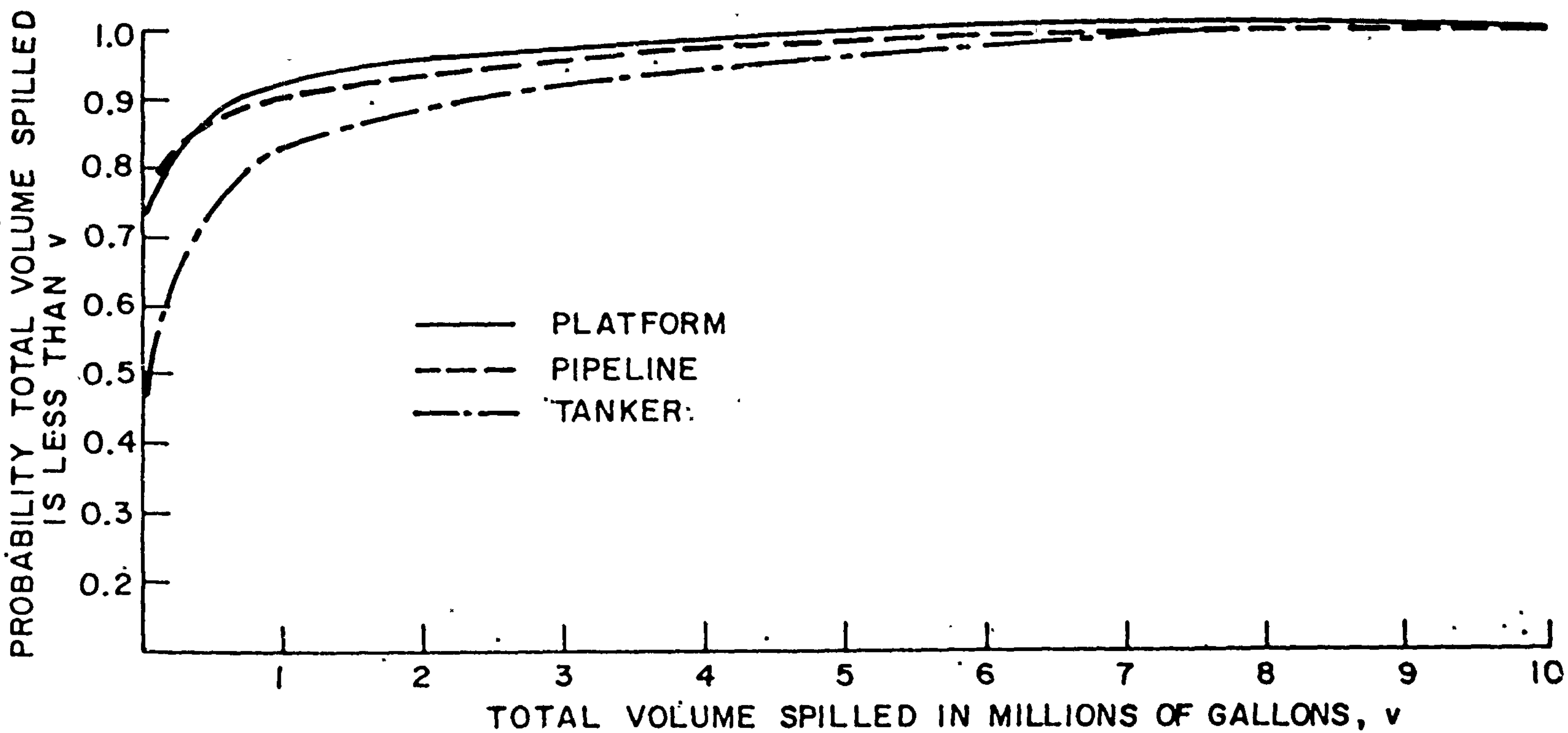


FIGURE 18.—Cumulative of Total Volume Spilled from Small Find over Field Life in Spills Larger than 42,000 Gallons (1000 bbl.)

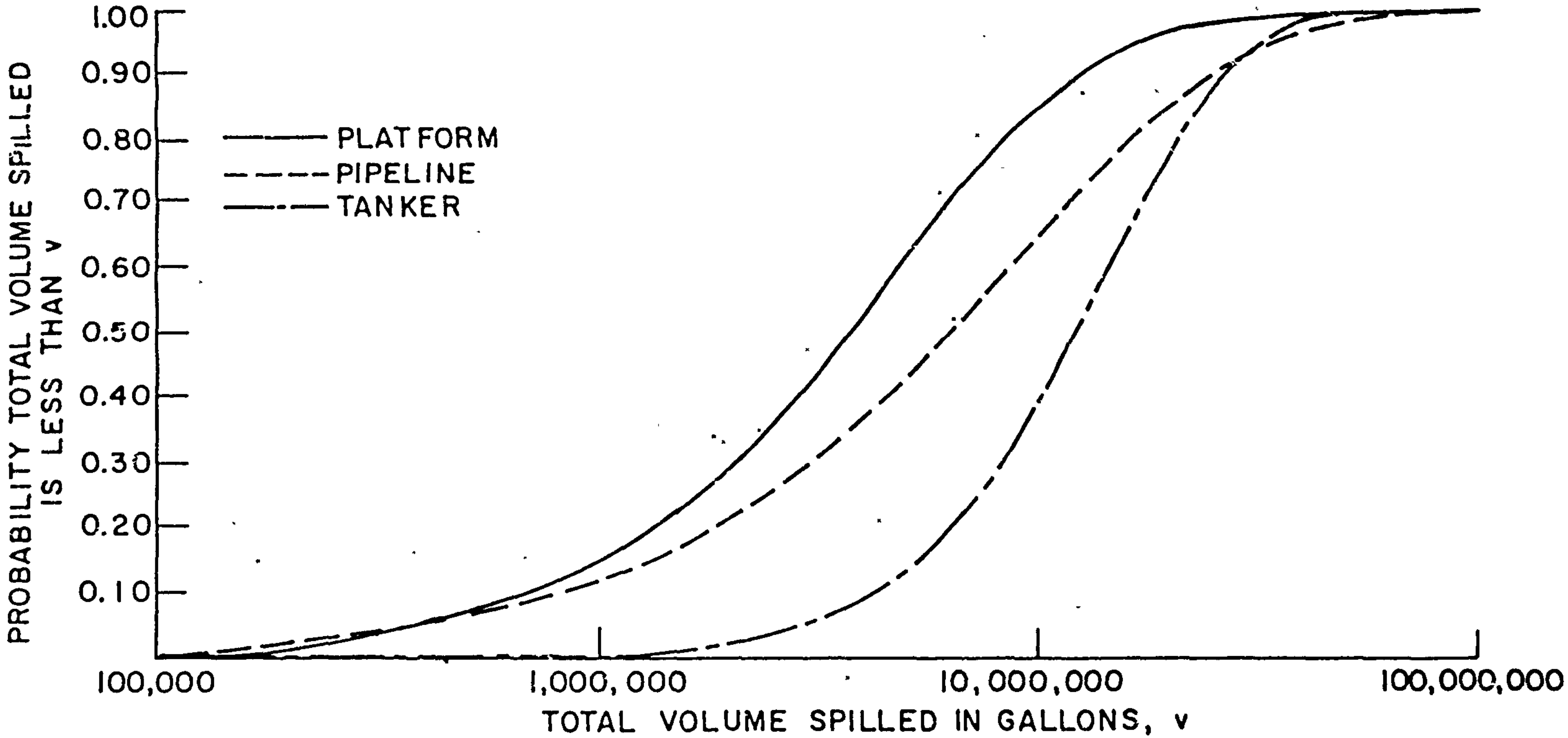


FIGURE 19.—Cumulative of Total Volume Spilled over Field Life for Large Find in Spills Greater than 42,000 Gallons.

Source: Massachusetts Institute of Technology, "Oil Spill Trajectory Studies for Atlantic Coast and Gulf of Alaska," *Primary, Physical Impacts of Offshore Petroleum Developments*, prepared for the Council on Environmental Quality under contract No. EQC330 (Cambridge: Massachusetts Institute of Technology, 1974), Report No. MITSG 74–20.

TABLE 3.—OIL SPILLED OVER THE LIFE OF A FIELD

	Number of spills	Total volume (barrels)
Small find:		
Platform	0.28	7,200
Pipeline	.31	13,900
Tanker	.41	19,000
Medium find:		
Platform	1.3	33,300
Pipeline	1.4	62,900
Tanker	1.9	92,400
Large find:		
Platform	4.7	120,500
Pipeline	5.2	233,300
Tanker	6.9	335,700

Source: Massachusetts Institute of Technology, "Oil Spill Trajectory Studies for Atlantic Coast and Gulf of Alaska's Primary, Physical Impacts of Offshore Petroleum Developments, prepared for the Council on Environmental Quality under contract No. EQC330 (Cambridge: Massachusetts Institute of Technology, 1974), Rept. No. MITSG 74-20.

With regard to platform spills over 1,000 barrels (bbls) the MIT analysis indicates that for a small find there is a 75 percent probability of no spill occurring, a 20 percent chance of once such spill, and more than one spill is very unlikely. For a large find there is a high probability of between 1 and 7 large platform spills.

The MIT results, with respect to offshore pipeline spills over 1,000 bbls, indicate a 75 percent probability of no spills, a 20 percent probability of one spill, and little likelihood of more than one spill. For a large field, based on past records there is a high probability of somewhere between 1 and 9 large pipeline spills.

Biologically, the time interval between large spills may be at least as important as the number of such spills. The MIT analysis, which is based on the amount of oil produced, indicates the probability of successive oil spills increases rapidly as the size of the field increases. For example, the expected time interval between large spills for a small field is 4 to 5 years; the corresponding time interval for a medium field is approximately 2 years; and only 1 year for a large field.

The MIT group suggests that these probability estimates should be regarded as moderately pessimistic as they assume no improvement in technology or operations as have occurred over the recent past. Furthermore, the estimates are based on the amount of oil brought ashore rather than other variables such as the number of platforms or, in the case of tankers, the number of landfalls. These considerations are important as the potential for oil spills to occur is also likely to be a function of the number of opportunities for a spill rather than entirely a function of the volume produced. For example, one would expect the spillage from 10 wells, each producing 1,000 barrels per day, to be less than from 100 wells each producing 100 barrels per day (even though the volume produced is the same in each case). The reason is the first case has fewer wells or independent units subject to accident or failure. Likewise one might expect the spillage from one 30-well platform to be less than from five 6-well platforms. Current trends are toward more wells per platform.

The Department of the Interior used a throughput analysis to express spill probabilities. This method involves a calculation based on the concept that for a certain volume of oil produced a certain volume will be spilled by each of several causes. The results of these calculations are summarized in table 4. Throughout spill rates are based on data of past spills. Forecasting future spills on this basis requires the following assumptions: (1) The success of spill prevention in the future and in areas with new environmental conditions will be the same as in the past, and (2) the data is sufficient. Table 5 is an attempt by the Department of the Interior to combine throughput spill rates with projections or assumptions of annual production for various areas to arrive at estimates of annual spillage. This calculation incorporated several other assumptions such as: (1) For deepwater areas, 200 meters to 2,500 meters, tankers will be necessary to transport the oil to shore, (2) all Alaskan OCS production will be pipelined to shore for storage, then tankered out of Alaska for refining and consumption in other areas, and (3) production in all other OCS areas will be piped ashore and consumed in the adjacent coastal area. Recognizing the inherent problems in this forecast, the Department of the Interior honestly states, "When all of the assumptions necessary for the validity of throughput spill rates are considered, it is highly doubtful that there is much, if any, meaning in these estimates."[40] Rather than absolute amounts they suggest that general categories of annual spillage may be more valid. These categories (based on the same assumptions) are as follows:

High.—Chukchi Sea; Beaufort Sea; Bering Sea; Central and Western Gulf of Mexico shallow and deep.

Moderately High.—Southern California shallow and deep; Gulf of Alaska; Santa Barbara shallow and deep.

Moderate.—Cook Inlet; MAFLA shallow and deep; Bristol Bay; Mid-Atlantic; North Atlantic.

Low.—North and Central California; South Atlantic; Aleutian Shelf; Washington and Oregon.

TABLE 4—*Throughput spill rates*

Accident class	*Spill rate (percent)*
1. Pipeline accidents	[1] 0.00170
2. Blowouts	[2] .00290
3. Explosions and fires	.00290
4. Severe storms	.00041
5. Ship collisions with platforms	.00009
6. Tanker and tank barge	[3] .01600
7. Other spills of 50 barrels or more	.00032
8. Minor spills	.00058
Total without tankers	.00890
Total with tankers and without pipelines	.02320
Total with both tankers and pipelines	.02490

[1] Pipeline spill rate since 1970.
[2] Blowouts expressed as throughput spill rate. An alternative expression is .035 percent of wells drilled blowout with an average spill of 2,100 barrels per blowout.
[3] The M.I.T. estimate of tanker throughput spill rate.

Source: Department of the Interior, FES 75, op. cit., p. 47.

[40] U.S. Department of the Interior. "Final Environmental Statement: Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf," FES 75, vol. 2, 1975, p. 54.

TABLE 5.—ESTIMATES OF AVERAGE ANNUAL OIL SPILL VOLUMES BASED ON THROUGHPUT SPILL RATES (OVER THE LIFE OF THE FIELD)

Areas	Average annual production (million barrels) Mean	Average annual production (million barrels) 5 percent	Throughput spill rate percent (table 109)	Average annual spillage (barrels) Mean	Average annual spillage (barrels) 5 percent
North Atlantic	45.00	71.43	0.0089	4,005	6,357
Mid-Atlantic	72.00	131.42	.0089	6,408	11,696
South Atlantic	20.00	43.33	.0083	1,780	3,856
MAFLA	50.00	77.14	.0089	4,450	6,865
MAFLA Deep	(25.00)	(43.33)	.0232	(5,800)	(10,053)
Central Gulf and South Texas	126.67	160.00	.0089	11,723	14,240
DEEP	(36.00)	(54.29)	.0232	(8,352)	(12,595)
Southern California	44.00	60.00	.0089	3,916	5,340
DEEP	(48.00)	(82.86)	.0232	(11,136)	(19,224)
Santa Barbara	60.00	85.71	.0089	5,340	7,628
DEEP	(36.00)	(60.00)	.0232	(8,352)	(13,920)
Northern California	26.67	26.67	.0089	2,374	2,374
Washington-Oregon	13.33	23.33	.0089	1,186	2,076
Cook Inlet	48.00	68.57	.0249	11,952	17,074
Gulf of Alaska	60.00	134.29	.0249	14,940	33,438
Aleutian Shelf	6.67	8.00	.0249	1,661	1,992
Bristol Bay	35.00	68.57	.0249	8,715	17,074
Bering Sea	88.00	175.00	.0249	21,912	43,575
Chukchi Sea	213.33	362.50	.0249	53,120	90,263
Beaufort Sea	110.00	190.00	.0249	27,390	47,310

Source: Department of the Interior, FES 75, vol. 2, op. cit., p. 52.

Another treatment of spill statistics was prepared by Dames and Moore for the Western Oil and Gas Association.[41] One of their objectives was to calculate recurrence intervals for various spill sizes from various causes (Table 6). For example, a spill the size of the Santa Barbara event, 75,000 barrels, would be expected to occur once every 143 years from drilling and platforms, once every 277 years from marine transports, or once every 94 years when combining all causes. These recurrence intervals were calculated from a cumulative distribution function for the spill sizes actually observed in historical data. However, the spill frequency for platform and drilling spills was reduced to reflect safety improvements expected during the OCS operations.

TABLE 6.—ESTIMATED RETURN PERIOD FOR MAJOR OIL SPILLS BASED ON ADVANCED TECHNOLOGY

	Average recurrence interval, years: Tanker/barge casualties	Drilling and platform spills	All causes
Spill size (barrels):			
5,000	8	22	6
10,000	14	31	10
20,000	33	45	19
40,000	91	76	41
60,000	176	113	69
75,000	277	143	94
80,000	307	153	102
100,000	492	201	143

Source: Dames and Moore, op. cit., p. 51.

[41] Dames and Moore, op. cit., p. 50–53.

Pollution From Blowouts

Excluding hurricane damage, 42 wells of a total of 12,715 drilled on the outer continental shelf have blown out. This equals a rate of 0.33 percent of the wells drilled through 1974 that have blown out. Most blowouts release only gas. This is reasonable to expect since blowouts are basically caused by rapid release of gas under high pressure. Gas is less damaging to the environment than oil although the possibility of fire from the blowout is greater when large amounts of gas are released. According to U.S. Geological Survey reports, there were 57 major accidents on the OCS through the end of 1974.[42] The U.S. Geological Survey defines major accidents as spillage in excess of 238 bbl. (10,000 gals.) and includes blowouts, explosions and fires creating major structural damage or blowouts, and explosions and fires resulting in loss of life. The accident rate has been declining since 1968.[43] The Geological Survey reports a total of 53 oil spill incidents involving 50 bbl or more of oil and condensate for the 1964–1974 period. Two of these occurred in the California OCS and the remainder in the Gulf of Mexico. Three of these incidents in the Gulf of Mexico and one in the California OCS were attributed to blowouts during drilling. Based on this record a blowout rate likely to cause a spill of 50 bbl or more is 0.04 percent.

The blowout record in British offshore waters is similar. Of more than 600 offshore wells drilled in British waters, four blowouts have occurred, the most recent in 1971. All four blowouts released only gas. According to a recent survey commissioned by Scottish office, the history of North Sea pollution dangers "cannot be entirely discounted. Nevertheless it is not great." [44]

The distribution of the 44 spill incidents of 50 bbl or more occurring in the Gulf of Mexico during the period 1964–1974 (first quarter of 1974) is given in Figure 20. However, as stated above, projections based on these records of past accidents fail to take into account technological and operating improvements made since 1964. These improvements include: (1) methods for controlling and monitoring pipeline corrosion, (2) techniques for early detection of pipeline leakage, (3) drilling blowout preventors and mud system safety controls, (4) spill prevention training programs for industry personnel, and (5) navigation aids for shipping. Industry experts project that such improvements would likely reduce by 50 to 75 percent the historical spill rates for pipeline accidents, drilling blowouts, and tanker/barge spills.[45]

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[42] U.S. Department of the Interior. Final Environmental Statement. OCS Sale 35, Southern California, vol. 2, 1975, p. 26.
[43] Ibid., p. 26.
[44] Journal of Commerce. "Risks of Marine, Coastal Pollution From N. Sea Oil, Gas Seen Minimal," Sept. 23, 1975, p. 3, 10.
[45] Dames and Moore, op. cit., p. 48.

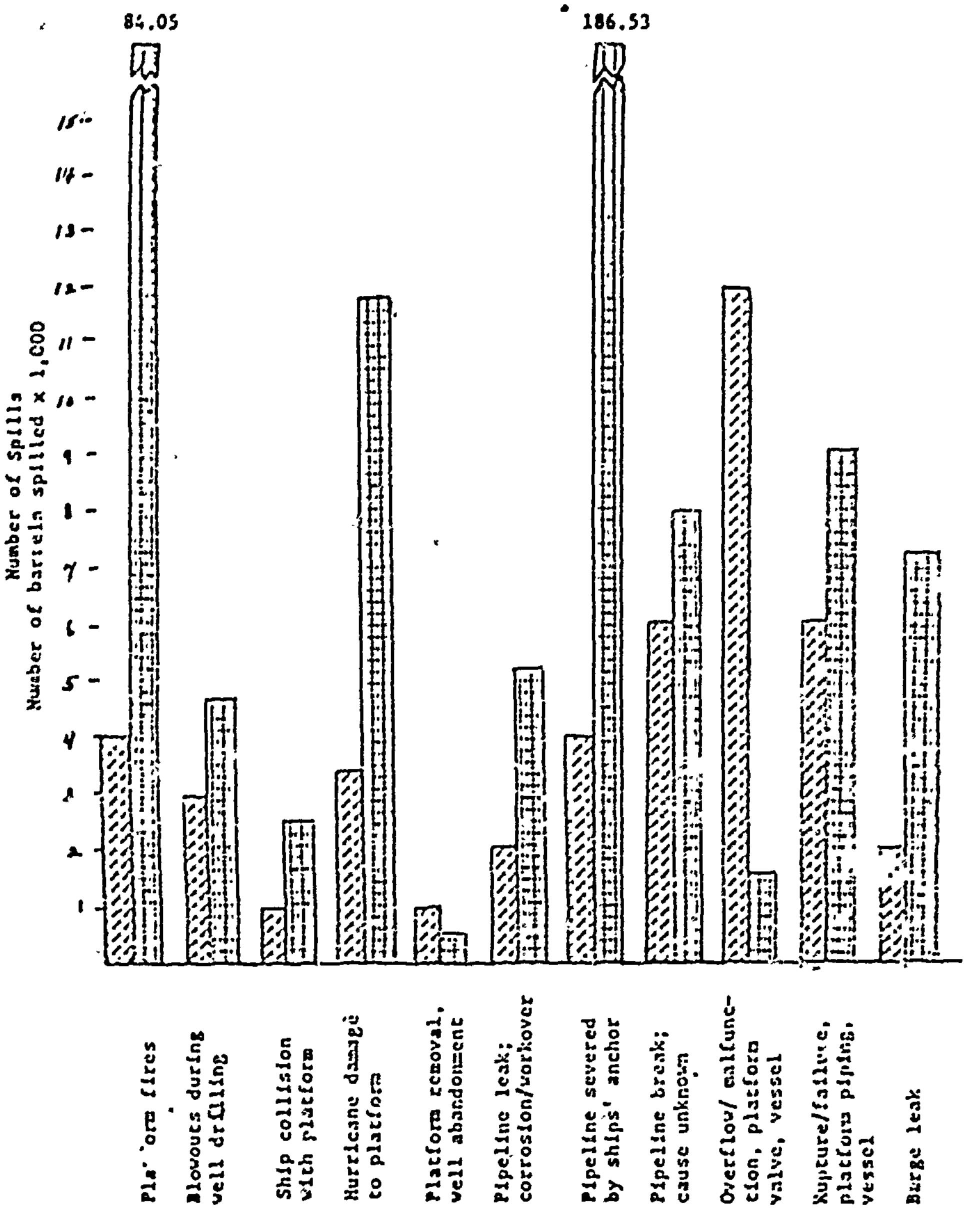

Figure 20—Oil Spills ≥ 50 bbl. Number and Amount (Data from Geological Survey.)

Amount of Oil Spilled   Number of Spills

Pollution From Platform Fires

Fires are always a major hazard in the petroleum industry. Most platform fires are ignited by arcing electrical equipment and overheated mechanical devices. The majority of fires are quickly extinguished with little or no damage, but if a storage tank or well catches fire major damage may result. If a producing well catches fire, it may be allowed to burn while it is being brought under control in order to minimize petroleum pollution. This was the decision made in the case of the Shell Bay Marchand fire in 1970.

The number of explosions and fires recorded through 1974 total 140 of which only six have resulted in pollution of the sea. However, 61 deaths have occurred and 143 workers have been injured from these accidents. Since 1971, explosion and fire accidents have not resulted in more than minimal oil spills. One reason is that Gulf of Mexico OCS Order No. 5 (1972) and Pacific OCS Order No. 5 (1971) require surface controlled subsurface safety devices in all new well completions. Reliable methods of shutting off the wells in the event of an emergency will probably limit future platform fires to the volume of flammable material in storage on the platform at the time the fire starts.

Pollution From Ships Colliding With Platforms

Significant damage can result from ship collisions with platforms. Accident records indicate only one such accident, resulting in a spill from a platform of greater than 50 bbl. through 1974. In April 1964, a freighter off the coast of Louisiana struck a platform and ruptured a storage tank spilling 2,560 barrels of oil into the ocean. However, this category does not include oil spilled from ships involved in a platform collision. Ship spills are reported as tanker/barge accidents and transfer operations.

Spills From Tanker and Barge Accidents and Operations

Accidental oil spills from tankers and barges, as well as oil discharged through normal operations are among the largest sources of oil spills in U.S. waters. Most tanker spills in U.S. waters involve imported oil. Approximately 98 percent of the oil and all natural gas produced offshore is transported to shore by pipeline and only the remaining 2 percent is transported by barge. Pipelines have been determined safer and more economical for transporting petroleum onshore from offshore platforms. However, it in anticipated that in the early developmental stages or in tracts separated from land by deep water some barging or tankering may be necessary.

Most large tanker spills occur near shore and are caused by groundings, rammings (with fixed structures), or collisions with other ships. Groundings and rammings occur near shore and collisions depend on traffic density which is highest near shore. Other than Alaskan oil, which will probably be brought to the West Coast by tanker, most offshore production that is not brought to shore by pipeline will probably be barged ashore. According to U.S. Coast Guard statistics, in 1972 tank barges were involved in 830 spill incidents producing 19.9 percent of the oil volume reported spilled in that year.[46] In 1973 tank barges were reported involved in 718 spill events contributing 6.5 percent of the volume spilled.[47]

Using a data base of worldwide tanker spills, the MIT analysis indicates that if tankers are used to transport oil to shore, the probability

[46] U.S. Coast Guard. "Polluting Incidents in and Around U.S. Waters, Calendar Year 1972." 11 p.

[47] U.S. Coast Guard. "Polluting Incidents in and Around U.S. Waters, Calendar Year 1973." 11 p.

of at least one oil spill over 1,000 barrels is about 27 percent during the life of a small field, about 85 percent for a medium field, and nearly 100 percent for a large field. The expected time interval between spills larger than 1,000 barrels is approximately 2.5 years for a small field, slightly over one year for a medium find, and slightly over one half a year for a large find.

Pipeline Spills

Pipeline accidents have released more oil to the marine environment than all other sources directly related to OCS operations. The largest spills occurred prior to 1970 and resulted from pipeline ruptures caused by anchor dragging. One of the largest pipeline spills occurred in October 1967 when a vessel dragging its anchor in a storm severed a pipeline about 20 miles west of the mouth of Southwest Pass, Mississippi River delta, Louisiana. The resulting spill went undetected for ten days and released over 160,00 bbl of oil into the Gulf of Mexico. Four major pipeline breaks have occurred on the OCS. Since 1970 spillage from pipelines has been considerably reduced as a result of several actions.

Beginning in 1969, the Bureau of Land Management has required all new common carrier pipelines to be buried a minimum of three feet out to a water depth of 200 feet. In shipping fairways and anchorage areas, pipelines must be buried at least 10 feet deep. Only lines in the gathering system between adjacent platforms may remain unburied. In some areas, such as the Southern California OCS, the water depth requirement may be increased to 250 feet. In addition, offshore pipelines are required to be coated with moisture impervious materials followed in many cases by a layer of dense concrete for mechanical and corrosion protection. Electrolytic protection against corrosion is also required. Other regulations call for continuous line pressure monitoring systems with automatic shut down valves or alarms, and regular pipeline inspection for leaks.

Industry spokesmen estimate that 48 percent of all pipeline leaks occur in lines that have been in use for 15 years or more.[48] This would suggest that the recent improvement in pipeline spillage may not continue as existing pipelines, especially those installed before 1970 which may not be coated or buried, reach states of more advanced corrosion.

The MIT spill analysis projects about a 25 percent probability of one pipeline spill over 1,000 barrels over the life of a small field, about a 70 percent chance of one such spill for a medium field, and a 95 percent probability for a large field.

Oil Spills From Natural Hazards—Hurricanes

In the history of OCS oil and gas activities, only one natural hazard has caused significant oil spillage. On October 3, 1964, three platforms on the OCS off central Louisiana were destroyed by a hurricane. The total volume of oil spilled was approximately 12,000 barrels, all of which was from tanks on the platforms. Several major hurricanes have passed through the petroleum production areas in Federal waters of the Gulf of Mexico and have caused financial damage

[48] U.S. Department of the Interior. "Final Environmental Statement. Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf," FES 75, vol. 2, 1975, pp. 33–34.

to the industry, but have not resulted in major oil pollution. For example, on August 17, 1969, Hurricane Camille, with top winds estimated at 201.5 miles per hour and a storm surge 22.6 feet above sea level, destroyed one production platform and damaged two others and also destroyed two drilling rigs and left three damaged. No significant oil spillage occurred.

When hurricane or serious storm warnings are advised, all oil and gas facilities in the path of the storm are evacuated. All surface equipment and wellhead controls are shut-in. In addition, blank tubing plugs are set in as many wells as possible to further reduce the possibility of pollution if the well is damaged.

CONTAINMENT AND CLEANUP TECHNOLOGY

Although there has been great improvement and development in the past five years, technology for containing and cleaning up oil spills is limited. Research efforts in this area, both federal and private continue to increase. The problem is not simple. Some oil spills spread over tens of square miles and control equipment is subjected to enormous forces from wind and waves. Spills occur at random and are frequently caused by severe storms which are the most difficult conditions for containment and cleanup. The problems of dealing with large areas of the ocean covered by thin films of oil moving under the tremendous forces of wind and waves are staggering. Nevertheless, several spill response technologies have been developed. These may be grouped into three categories: containment barriers, oil recovery devices, and treating agents.

Containment Barriers

Oil spill containment barriers or booms are floating devices generally resembling short curtains that prevent an oil slick from spreading beyond the barrier. Several designs have been produced for conditions ranging from protected waters to open ocean. Some types of barriers are designed to be towed, while others are stationary. Barriers designed for calm protected waters would not be effective in strong currents or high waves.

Typical barriers have a vertical height ranging from 6 inches to 5 feet. An effective barrier must ride evenly with the waves and not dip below the top of the slick or rise above the bottom. The major limitations to the effectiveness of containment barriers are speed of current (or towing speed if the barrier is not stationary), height of waves, and thickness of the slick.

In a current, one problem is to design a barrier that is ballasted to remain vertical and to maintain the proper height in the water. Other problems of containing oil in a current are related to the hydrodynamics of oil in moving water. As an oil slick increases in thickness it extends farther downward in the water. Only about 10 percent of the slick rises above the waterline. In other words, an oil slick floats in much the same way as an iceberg. As a current increases more oil is driven against the barrier. When a critical current speed for the depth of the barrier is exceeded, oil will migrate down the barrier and pass underneath. Another problem is entrainment or dispersion of oil droplets in the water as it flows past a slick held against a barrier. The rate at which droplets of oil are driven into the water and flow beneath the barrier depends on the current speed and the properties of the oil itself. Both entrainment and migration of the slick under a barrier become significant problems at current speeds in excess of one knot. The difficulties in handling barriers in the open ocean are compounded by the necessity for ships to navigate at very low speeds when it is difficult to maintain steering control.

The best barrier is not only one that is adequate for the job but also can be deployed rapidly and easily. Barriers have generally been of limited success on the open ocean for the reasons given. However, after a major research effort the U.S. Coast Guard has recently developed an open ocean barrier system capable of being easily transported by air and dropped where needed within four hours after notification of a spill incident. The system is designed to be effective in 5-foot seas, 20-mile per hour winds, and currents up to 1 knot, and can survive 10-foot seas with 40-mile-per-hour winds.

Air bubble barriers are another type of containment device. If air is pumped into a perforated pipe below the surface, the rising bubbles cause the surface water to flow away from the pipe. As with containment booms, air barriers are most effective in calm water. An air-bubble barrier was employed at the Santa Barbara spill but was not successful because of operational problems. Fairly large amounts of compressed air are required for an air bubble barrier to be effective.

Oil Recovery Devices

Several devices have been produced for collecting oil from the surface of the sea. Since the efficiency of an oil recovery device is improved by increasing the thickness or depth of the oil slick, these devices are frequently used inside a containment barrier. Oil recovery devices include suction-types, weir-types, and moving surface-types.

Suction skimmers float on the surface and use suction pumps to draw in oil and water through tiny holes. A weir-type skimmer has a vertical dam or weir around it over which oil floats. A suction pump is frequently used with the weir to recover the oil. Both weir and suction oil recovery devices work best in calm water.

Moving surface skimmers utilize a moving material which absorbs or causes oil to adhere to it in preference to water. The oil coated material then passes over a scraper, squeezer, or other device to remove and recover the oil. Skimming devices of this type have the problem of tending to drive oil away from themselves by the motion of the absorbing or collecting surface.

In April 1975, a large spill recovery unit was installed-offshore on a permanent basis at an oil rig about 60 miles off the Florida coast in the Gulf of Mexico. The unit is installed in a converted shrimp trawler moored at the rig. It has a recovery capacity of 100 to 600 barrels an hour, depending on sea turbulence, and is reported to be the largest unit on standby duty offshore.[49]

Treating Agents

Several types of treating agents are available. Their usage depends to a large extent on the conditions of the individual spill and guide-

[49] *Offshore*, October 1975, p. 141.

lines or restrictions controlling their application. Among the treating agents that have been used are:

1. Dispersants—chemicals forming oil-in-water suspensions;
2. Sinking agents—materials that mix with the oil and create a mixture dense enough to sink:
3. Burning agents—material put on the slick to assist ignition or enhance combustion of spilled oil;
4. Biodegradants—substances that promote oxidation of oil by microbial action;
5. Gelling agents—chemicals that form semi-solid oil agglomerates to facilitate removal;
6. Herding agents—chemicals that concentrate the spilled oil in a small area;
7. Sorbants—materials that absorb oil to form a floating mass for later collection and removal.

Perhaps the most controversial treating agents are the dispersants. In the past, studies where dispersants were used have indicated the environmental damage resulting from the toxicity of the dispersant itself and from the increased oil surface to which organisms were exposed was significant. Consequently, in August 1971, the Council on Environmental Quality developed a National Oil and Hazardous Materials Pollution Contingency Plan which prohibits the use of dispersants as follows:

1. On any distillate fuel oil;
2. On any spill of less than 200 barrels;
3. On any shoreline;
4. In waters less than 500 feet deep;
5. In waters containing major fish populations, or breeding or passage areas for species of fish or marine life that may be damaged or become less marketable by exposure to dispersant or dispersed oil;
6. In waters where winds or currents could carry dispersed oil to shore within 24 hours (in the judgment of the Environmental Protection Agency);
7. In waters where the surface water supply would be affected.

However, these restrictions may be waived if, in the judgment of the Coast Guard or the Environmental Protection Agency (EPA), their use will prevent or substantially reduce the hazard of fire or cause the least overall environmental damage.

In other countries, such as Great Britain, the use of dispersants is standard practice for combating oil spills. Dispersants enhance biodegradation of the slick by increasing the surface area. From a cost-effectiveness viewpoint, studies indicate that dispersants are the most practical means of dealing with an oil spill.[50]

A substantial research effort has gone into developing less toxic dispersants and dispersants that mix readily with the oil slick. The mixing problem was demonstrated in the Santa Barbara spill where after the dispersant was spread in a fine mist over the slick, it was found necessary to run boats through the slick to mix the dispersant into

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[50] James, W. P. "Environmental Aspects of a Supertanker Port on the Texas Gulf Coast." Texas A and M University, College Station, Texas, 1972.

the oil by propeller action. Low toxicity dispersants are now available, but the full effects of dispersed oil in the marine environment are not known.

Sinking agents, such as hydrophobic chalk, have been used to prevent oil from reaching shore. The French used about 3000 tons of powdered chalk to sink an estimated 20,000 tons of oil following the *Torrey Canyon* spill. Very little sunken oil came ashore. The effects on bottom life are not known, but apparently fishing in the area has not been adversely affected. In this country, sinking agents may be used only under special circumstances and with the approval of EPA.

Burning agents are of several types such as: (1) wicking agents to provide a surface for the oil to burn on; (2) auto-igniters to react with the more combustible components of the oil slick in order to ignite the oil; (3) hydro-igniters which react with water to produce heat and hydrogen to ignite the slick; and (4) ignition assisters or flammable materials that burn and raise the temperature enough to keep the crude oil burning.

There are several problems with the use of burning agents, such as air pollution and residues produced from incomplete combustion. Although research is continuing, there are no burning agents that will completely oxidize an oil slick. Another problem is logistics as the larger the spill the larger the volume of burning agents required. Consequently, burning is most successful on small relatively thick spills.

Biodegradants are bacteria or nutrients used to enhance biological oxidation of oil which would happen more slowly under natural conditions. Biodegradants have been studied for some time and have recently been developed for cleaning tankers during long ballast voyages. Their use in cleaning up oil spills seems promising but at present their use remains largely untried.

Gelling agents are primarily directed toward the problem of tanker accidents where in some cases pollution might be avoided or diminished by gelling the oil in the tanks. Gelling oil requires mixing gelling agents with oil and allowing adequate time for the gel to set. A gel of modest strength can be formed in 8 hours and triple in strength after 130 hours. Cost and mixing problems are major constraints.

Herding agents tend to contract a spill and keep it from spreading. The advantage of this is to facilitate cleanup and removal. Herding agents are limited in effectiveness and are more successful in controlling small thin slicks.

Sorbents are considered by some investigators the safest and most effective treating agents.[51] Historically, the most common method of dealing with manageable amounts of oil has been to use straw as a sorbent. Straw can absorb approximately 5 times its own weight in oil. Substantial research has been conducted on sorbent materials. Reticulated polyurethane foam has been found to absorb up to 30 times its own weight in oil and can be recovered by passing the material through wringers. Adverse sea conditions do not seriously diminish the effectiveness of sorbent materials. A major disadvantage is the amount of manual labor required for recovering the sorbent. Improved mechanization of retrieval methods would significantly enhance the use of sorbents.

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[51] Boesch, et al, op. cit., p. 90.

CHAPTER V. ENVIRONMENTAL IMPACT ON THE COASTAL ZONE

The coastal zone is the band of dry land and adjacent ocean space in which land ecology and use directly interacts with ocean ecology and use. The coastal zone is one of the most senstitve and biologically productive areas of the marine environment. Because of the importance of the coastal zone to marine ecosystems, the environmental impacts from OCS oil and gas operations are likely to be most critical in this area.

ESTUARINE AREAS

An estuary is a broad shallow embayment at the mouth of a river through which the environment grades from fresh water to marine conditions. Estuaries are highly productive areas biologically. Estuarine areas are frequently subjected to the intense pressure of multiple uses by man. They are expected to assimilate industrial and municipal waste discharges, urban runoff, accommodate marine transportation, and at the same time remain productive fisheries and shellfisheries areas. Millions of barrels of waste oil pass through estuaries yearly. Oil spills occur from ships and terminals often located in estuaries. Refineries located on estuaries have contributed to the oil pollution of estuarine waters. Accidental spills from offshore oil production can also contribute to estuarine pollution. With the many pressures on them, few estuaries in developed areas remain virgin of some oil contamination.

Possibly because most oil spills in estuaries have been small or have involved petroleum products, the biological effects (particularly long-term effects) of crude oil spills in estuaries have not been well studied. Marshlands can be affected by repeated oilings, but a single large oiling apparently does not prevent recovery of the area. However, chronic oil pollution has a decidedly detrimental effect on marshland ecosystems.

Several characteristics of estuaries tend to magnify the effects of oil pollution if a spill should occur. Estuaries are generally shallow, relatively confined bodies of water in which spilled oil would have a high probability of reaching shore or becoming incorporated into sediments. If a spill occurred in an estuary, the oil would have little chance to weather before coming into contact with living organisms. If a spill occurred on the OCS adjacent to an estuary, wind and weather conditions at the time would be a major factor in determining the magnitude of the impact on the estuary. Although the net flow is outward, oil could easily be driven into an estuary or enter with the normal influx of seawater. Estuarine waters are normally turbid, and floating oil would tend to absorb and adsorb onto fine sediment particles. Oil absorbed and adsorbed onto sediment would eventually sink where it could kill or contaminate bottom-dwelling organisms. Taste tainting of shellfish resulting in the temporary closing of shellfishing areas has been a particular problem. Furthermore, oil deposited in sediments under the typical anaerobic or reducing conditions found in estuarine sediments will persist for long periods of time.

One factor mitigating the impact of oil pollution is the high biological productivity of estuaries. Microbial biota are abundant and aerobic degradation of the oil not trapped within the sediments is rapid. If the pollution is not persistent or chronic (that is, if there is only a single or occasional spill), damaged communities should recover rapidly because of the high reproductive potential and annual turnover typical of many estuarine organisms.

DESTRUCTION OF WETLANDS AND ITS EFFECT ON FOOD CHAIN PRODUCTIVITY

Tidal wetlands are characteristic of many estuarine shores, bays, and sounds. Tidal wetlands in temporate climates generally consist of salt marshes dominated by grasses, and in more tropical areas mangrove swamps dominated by trees. Wetlands are among the most productive environments in the world and serve as habitat, feeding, or nesting grounds for shore birds, fish, and other wildlife. The great biological productivity of wetlands supports much of the life in surrounding waters through a food web based on vascular plant debris. Wetlands are also important geologically in stabilizing shorelines.

A number of studies have indicated that salt marshes are relatively resilient to many types of environmental stresses. The first concerted studies of oil pollution in marshes took place in Louisiana in 1950.[1] These studies were sponsored by the oil industry in response to charges by fishing interests of damage to marshlands from oil pollution from drilling. In these studies, marsh plants were coated with oil and changes in their biomass were measured. The experiments indicated that a moderate dosage of oil was not excessively harmful, but that repeated coatings proved lethal. Oiling was also found apparently to produce a "fertilizing" effect of stimulated growth.

Studies of the impacts on salt marshes of a number of spills of oil and refined products have been reported (Appendix XIX). These include the spills of the *Torrey Canyon*.[2] *Chryssi P. Goulandris*.[3] *Arrow*.[4] and the spill at West Falmouth.[5] Other experimental studies have been carried out.[6] Most of these investigations have reported that marsh plants survive light to moderate oiling in a single dosage. The immediate effects include the killing of heavily oiled shoots followed by regrowth from living roots. Very heavy oiling can smother marsh plants and multiple dosing can also do considerable damage to marsh

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[1] Mackin. J. G. "A Comparison of the Effect of Application of Crude Petroleum to Marsh Plants and to Oysters." Texas A & M Research Foundation, 1950. (Project Nine—unpublished report).

[2] Stebings. R.E. "Recovery of Salt Marsh in Brittany Sixteen Months After Heavy Pollution by Oil." Environmental Pollution v. 1970. p. 163–167.

[3] Cowell. E. B. "The Effects of Oil Pollution on Salt Marsh Communities in Pembrokeshire and Cornwall." Journal of Applied Ecology. v. 6. 1969. p. 133–142.

[4] Thomas. M. L. H. "Effects of Bunker C Oil on Intertidal and Lagoonal Biota in Chedabucto Bay. Nova Scotia." Journal of the Fisheries Research Board. v. 30. Canada 1973. p. 83–90.

[5] Burns. K. A. and J. M. Teal. "Hydrocarbon Incorpration into the Salt Marsh Ecosystem From the West Falmouth Oil Spill." Technical Report of the Woods Hole Oceanographic Institution. No. 71–69. 1971. 24 p.

[6] Baker. J. M. "Successive Spillages." In: Cowell. E. B., editor. Proceedings of the Symposium on the Ecological Effects of Oil Pollution in Littoral Communities. London. Nov. 30–Dec. 1. 1970. London Institute of Petroleum. 1971.

plants. The effect of oil on marsh plant species depends on the time of year, species involved, and type and amount of oil. Oiling during the growing season may cause damage that would not occur at other times. Oil may influence flowering, seed development, and vegetative reproduction by underground roots. If oiling does occur during the growing season, annual plants may suffer more than perennials, which regenerate from roots. Weathered oil with few aromatics is less toxic than fresh oil or light fuel oils (spills of refined products are not likely from offshore production). However, weathered oil reaching shore after the *Torrey Canyon* spill became an impermeable barrier to gas exchange of plants rather than a toxicity problem.

Apparent growth stimulation of plants following oil dosage has been reported on several occasions. Possible explanations for growth stimulation include: (1) increased water retention of oiled soil, (2) release of nutrients from oil-killed animals, (3) plant nutrients or growth regulators in oil itself, and (4) nitrogen-fixation by oil-degrading microorganisms.[7]

Most investigations of the effects of oil pollution on marshes have concentrated primarily on marsh plants. A wide range of intertidal and subtidal fauna have also been killed or contaminated. Investigations of the West Falmouth spill have shown that oil can penetrate at least 70 centimeters into the sediment and oil residues were detected in organisms from various levels of the food web for more than a year after the spill. An unexpected rise in sedimentary oil content of the estuarine muds in the Wild Harbor River Marsh was reported months after the West Falmouth spill. This rise was attributed to a release of oily material from the nearby marshland, thus, the system was able to "store" oil for later release. The new infusion caused additional adverse effects among the fauna. Although oil was taken up by many organisms, there was no evidence of food chain magnification. Direct uptake of petroleum hydrocarbons from the water or sediments appears to be more important than uptake from the food chain.

Biological effects from large oil spills vary widely making generalizations about productivity difficult. Plants have been shown to be severely damaged, virtually unharmed, and in some cases even stimulated in growth by oil spills. Two limitations on productivity are the availability of nutrients and the activities of herbivores. Nutrient availability is probably not affected by oil, but destruction of herbivores can occur. In the case of the *Tampico Maru* spill, the catastrophic reduction in grazing populations (primarily sea urchins) was shown to have led to a rapid population explosion of brown algae (kelp).[8] Productivity measurements defined on the basis of living protoplasm have shown that detritus feeders tolerant to stress rapidly undergo population explosions in the temporary absence of predators and competitors. An oil spill may cause a shift in the ecological distribution of organisms but probably have little effect on total productivity. The major concern is in whether the ecological shift destroys commercial or more desirable species. This tends to become a value

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[7] Boesch, D. F., C. H. Hershner and J. H. Milgram "Oil Spills and the Marine Environment." The Ford Foundation, 1974, p. 22.

[8] North, W. J., M. Neushul and K. A. Clendenning. "Successive Biological Changes Observed in a Marine Cove Exposed to a Large Spillage of Mineral Oil." In: Pollution Marines par les Produits Petrolliers, Symposium de Monaco, 1969, pp. 335–354.

judgment or socio-economic consideration in addition to an environmental concern. A further complication is that many species that were once considered valueless have since become commercially important.

Oysters and clams are among the most important commercial intertidal and shallow subtidal organisms of our coasts. Both can take up oil and become unfit for human consumption either through taste tainting or possible health effects. Contaminated shellfishing areas can be returned to commercially productive use after recovery. However, chronic exposure to oil pollution may not allow recovery of a fishing area. Loss of an entire species of commercial importance is unlikely as most commercially important species are more widespread than any area likely to be covered by an oil spill or chronically polluted from offshore oil and gas operations. Based on past experiences overfishing is much more likely to stress population levels of commercial species than environmental impacts.

The primary adverse impact on marshlands arising from development of oil and gas resources on the OCS would probably come from pipeline traversing. Construction and maintenance of pipelines involves channel dredging, creation of dredge spoil banks, and access for workers and equipment resulting in turbidity and resuspension of toxic substances, and alteration of salinity and circulation patterns from man-made channels. These activities can result in decreases in vegetation and habitat for organisms, as well as affecting the water quality on which the spawning and breeding of many commercially valuable species depends. However, this impact would be localized in the areas where pipelines came ashore and not all these areas would involve wetlands. Furthermore, collecting systems are used on the OCS so that the number of pipelines brought ashore is minimized. Production from new areas of the OCS could be brought ashore at points selected to minimize the environmental impact.

The experience in Louisiana can serve as a satisfactory source of information on the effects of OCS development on the productivity of the ecosystem. In testimony before the Ad Hoc Select Committee on the Outer Continental Shelf hearing in New Orleans, Dr. Lyle St. Amant, Assistant Director for Marine Fisheries and Coastal Management, Louisiana Wildlife and Fisheries Commission stated:

> The history of petroleum production in Louisiana and its effect of the coastal ecosystem probably represents to a maximum degree those types of experiences that might be expected in any marine petroleum-producing area in the world. I feel that this position can be taken for these reasons:
>
> (a) Petroleum has been produced in the estuaries and wetland areas of Louisiana for fifty years and offshore since 1937 (38 years). In this area there are now 25 to 30 thousand producing wells and approximately 38,000 miles of pipelines.
>
> (b) Environmental regulations and management was nonexistent during the initial twenty years of production. In the early years and during World War II, practically every accident and/or type of mismanagement, vis-a-vis, petroleum production in a marine environment, probably occurred in Louisiana.
>
> (c) After fifty years of exposure to oil production, we have no evidence that the fishery production of Louisiana has declined or is significantly difference from production in early years. Louisiana now produces as much as 1.2 billion pounds of commercial fish annually or 23% of the total U.S. fishery production. From this, it is reasonable to assume that even under the worst conditions and long exposure, it is not likely that marine productivity will be totally destroyed or even materially altered. Therefore, there

is adequate opportunity in new areas of exploration to determine the nature of impacts and to take corrective steps as we have done in Louisiana since 1950.[9]

Another indication that under conditions of heavy exposure to oil an ecosystem is not likely to be destroyed or even materially altered comes from the fact that during the war years, 1942 to 1945, over 1.1 million barrels of oil were spilled from tankers torpedoed off the East Coast of the United States.[10] Although reports of the coastal impact are not readily available because national defense measures included censorship of news that may have confirmed tanker sinkings, outward appearances would indicate that coastal habitats recovered in a relatively short period of time considering the amounts of oil spilled.

ENVIRONMENTAL IMPACTS ONSHORE

Development of new offshore oil and gas resources creates environmental impacts onshore. Onshore environmental impacts include land development, disruption from construction and temporary facilities, increased air and water pollution, changes in plant and animal habitats, and noise pollution from construction and operations. Selection of undeveloped land for OCS related oil and gas development is a major concern. Even if large oil and gas resources were found offshore, most adjacent coastal regions have sufficient undeveloped land to meet the development requirements, assuming environmental and locational values were ignored. However, large amounts of undeveloped land are really unavailable due to environmental values (e.g., wetlands, ecological sanctuaries, national parks and seashores, and coastal recreational areas), locational constraints (e.g., excessive slopes, inadequate water, and distance from major population centers), and such factors as local preference for agricultural preservation and low-density single family housing.

On the other hand, primary industry need not locate adjacent to offshore production areas. If a company has refining capacity in a particular area, it will probably expand that capacity to the practical limits. New refineries may be located inland from the environmentally stressed coastal areas. The benefits of transporting crude oil inland may exceed the costs.

Some indication of the primary land use requirements needed for support facilities for offshore oil and gas production can be gained from a study of the seven-state Mid-Atlantic region by Woodward-Clyde Consultants for the American Petroleum Institute. The study estimates that about four square miles would be needed in that region, of which about 1,000 acres or 40 percent would be for platform fabrication facilities.[11] The land requirements may be even less since the resource estimates the study was based on have since been lowered.

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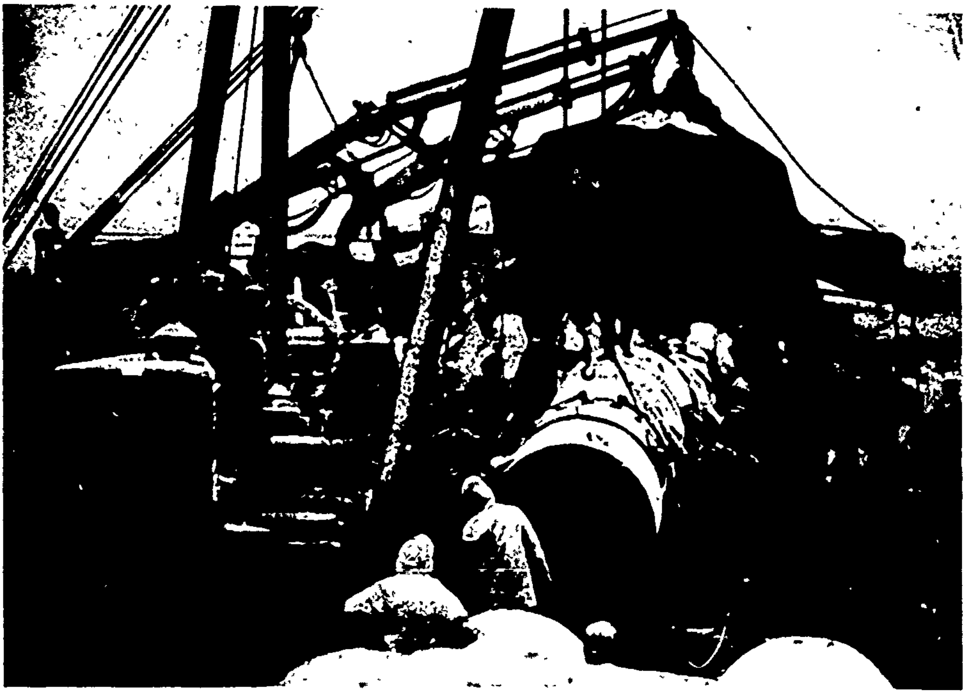
[9] St. Amant, Lyle S. Prepared Statement to the U.S. Congress, House Ad Hoc Select Committee on the Outer Continental Shelf hearing in New Orleans, Louisiana, June 7, 1975. Part 1. p. 68.

[10] U.S. Department of the Interior. "Draft Environmental Statement: Proposed 1976 Outer Continental Shelf Oil and Gas Lease Sale Offshore the Mid-Atlantic States." OCS Sale No. 40, vol. 1, 1975, p. 550.

[11] *The Oil Daily* Oct. 23, 1975, p. 4

See also: Woodward-Clyde consultants, "Mid Atlantic Regional Study, an assessment of the onshore effects of offshore oil and gas development," October 1975.



Laying Pipeline Onshore

Courtesy Exxon Corporation.

The impacts of OCS development on wildlife and vegetation depend mainly on the extent to which undeveloped land is developed, on local attitudes toward conservation in general, and upon the degree to which there are laws and formal systems which protect vegetation and wildlife in the state, county, and municipality involved. Design and siting decisions such as narrow pipeline corridors, restoration of any disturbed areas, and inland refinery locations can promote good wildlife management and prevent or mitigate environmental damage.

Some air and water degradation will also result from onshore development associated with oil and gas production on the OCS. Air pollution can arise from refinery emissions and evaporation of oil and oil products. Modern emission control equipment is available to reduce air pollution from refineries (with the possible exception of hydrocarbons) to within acceptable Federal standards. Airborne hydrocarbons are particularly difficult to control as they are not generally emitted from point sources but from any oil or oil product transfer operation or occasion when oil or petroleum product contacts air. Some hydrocarbon emissions bear objectionable odors, can cause respiratory problems, damage plants, or contribute to deterioration of materials.

In the event of a major spill, airborne hydrocarbons could reach objectionable levels. In some areas, such as, for example, southern California, air movements are onshore and pollutants do not become rapidly dispersed. Approximately one third of a spill would volatize and become an air pollutant. If a spill of 1000 bbls occurred near shore, this would load the coastal air with approximately 50 tons of petroleum hydrocarbons (PHCs). As a study for the Southern California Council of Local Governments Concerned With the Federal Proposal for Accelerated O.C.S. Oil and Gas Development Nationwide and in Southern California points out, essentially all these PHCs (except C–1 through C–3 hydrocarbons) would be photochemically reactive and be carried relatively undispersed into populated areas.[12] Air pollution from spills farther offshore or in areas with different wind patterns would not likely be as serious.

Water pollution can increase from refinery discharge and additional loads on sewage systems resulting from onshore development related to OCS oil and gas production. One measure of water quality is the biological oxygen demand (BOD) of effluent streams. The BOD of the water discharged from a typical refinery would be equivalent to the discharge of a municipal treatment plant serving 2,000 people and using secondary treatment.[13] Thermal impacts from water discharged from refineries may be beneficial or detrimental. Noise levels in the vicinity of refineries could also be objectionable although, by comparison, certainly less so than in the vicinity of airports. Isolated locations or surrounding undeveloped buffer zones could help mitigate this problem.

If an oil spill reaches a beach, the adverse impact may last from several weeks to several years, depending on the size of the spill and the size and location of the impacted area. Contaminated beaches will lose their recreational value until they recover or are cleaned up. If earth moving equipment such as bulldozers and front end loaders are used in beach clean-up, as at the Santa Barbara and *Arrow* oil spills, shoreline equilibrium may be upset by beach removal. Excessive removal of beach materials can lead to erosional problems if there is not sufficient resupply of materials to the beach area. In the history of OCS operations, two oil polluting incidents have had a severe impact on beaches, the Chevron fire and the Santa Barbara spill. However, even a small amount of oil on a heavily used recreational beach would produce a serious impact.

POLICIES TO LIMIT ADVERSE IMPACTS

Previous studies have suggested policies and specific actions to limit adverse impacts. Obviously, it is environmentally advantageous to prevent an oil spill from occurring. In the area of technology and environmental protection, the report by the Council on Environmental Quality (CEQ) entitled "OCS Oil and Gas—An Environmental

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[12] Pitts, J. N. Jr. and B. L. Finlayson, "An Assessment of the Air Quality Aspects of the Draft Environmental Statement for the Proposed 1975 OCS Oil and Gas General Lease Sale Offshore Southern California." In Final Environment Statement OCS Sale No. 35, southern California, vol. 3, 1975, pp. 207–459.

[13] Council on Environmental Quality, "OCS Oil and Gas—An Environmental Assessment," Report to the President, vol. 1, 1974, p. 122.

Assessment" points out that the man-machine interaction is the critical factor in minimizing the threat of accidents.[14] Improved understanding of the role of human factors in equipment design must be coupled with thorough training of the equipment operators.

Industry incentives have already led to the establishment of well control training schools, both in-house and through universities. However, training programs are optional and not uniform throughout the industry. The question arises whether the economic loss from accidents is sufficient incentive for industry to provide the necessary training or whether Federal standards and certification of critical OCS operating personnel should be established.

There seems to be little disagreement between industry and the Government on the need to use the best procedures and technology available to prevent blowouts and loss of well control. Federal regulations have been established for setting casing, installing blowout preventers and subsurface safety valves, and requiring numerous other equipment and procedures. It is likely that as soon as new technology is proved reliable and advantageous it will become required through Federal regulations. Required use of subsea production systems in some new OCS areas is one possibility. Federal-industry evaluation of new technology is particularly critical for OCS development in regions that have more severe natural hazards than previously developed areas.

One area of particular concern is the reporting of spills and assignment of causes. Methods of reporting spills have not been standardized, leading to some latitude in interpretation of the data. For example, according to the U.S. Coast Guard data in 1971, 56 percent of the offshore oil spills and 82 percent of the spill volume were attributed to pipelines. In 1972 the Coast Guard reported 2 percent of the offshore spills and 3 percent of the spill volume attributed to pipelines. As the CEQ report points out, much of this discrepancy may be due to whether or not spills were assigned to offshore production or offshore pipeline categories. Many spills occur near production platforms and some confusion in assigning the cause is likely. A standardized spill reporting system among the Departments of Interior and Transportation and the Environmental Protection Agency with emphasis on detailed causal relationships would be of benefit in evaluating spill probabilities with regard to limiting adverse impacts.

Policies for bringing oil ashore need to be formulated before a new area of the OCS is developed. Tankers may be used during early stages of a field's development or on a continuing basis from distant small or medium-size fields where the economics do not justify investment in pipelines. Questions that need to be resolved include requirements for tanker construction and the best means of incorporating into new and existing ships advanced accident prevention technologies such as improved maneuverability and communications. Adverse impacts from pipeline construction could be averted or limited by cooperative advanced planning among the Department of the Interior, other Fed-

[14] Council on Environmental Quality, op. cit., p. 163.

eral agencies, and the affected state and local governments. Planning for siting pipeline corridors should begin as soon as potentially producing OCS areas are known in order to minimize intrusion into environmentally sensitive marine and coastal areas.

More severe storms and seismic conditions in some areas may require new policies regarding offshore oil storage. Policies that emphasize prevention of spills are especially important in the new areas. Greater Federal oversight and evaluation of untested technology may be required.

The effectiveness of oil spill containment devices is limited under the high sea conditions that may be experienced in some new OCS areas. Questions as to the environmental impact as well as the effectiveness of oil spill cleanup technology need to be resolved. Appropriate areas may be designated as especially critical environmentally in which no OCS development should occur or in which certain cleanup methods should or should not be used. Coordination of relevant Federal and State agencies would aid in identifying critical areas. Oil spill contingency planning and policies would benefit from coordination of Federal and State agencies with industry groups.

Any oil spill will have a negative environmental impact. Of concern to the policy maker is the question, what level of significance is unacceptable? Obviously the answer would be different for different areas. Even a short term impact could be an unacceptable risk to a resort community, but may be considered a necessary risk trade off in another area. Oil trapped in sediments has a long residence time, but its absolute presence or low concentration may be of little significance to the total ecosystem of the area. On the other hand, trapped oil may be released slowly causing chronic pollution. There are no simple answers to problems such as these, and few attempts have even been made. Most oil pollution research to date has been directed toward identifying environmental impacts but there has been little attempt to evaluate these impacts as to their significance or to place them in perspective. It is in this area between researcher and policy maker that further efforts are needed to bring the data of the researcher into a form useful to the decision makers.

A recent study for the Ford Foundation entitled "Oil Spills and the Marine Environment"[3] concluded:

> The ecological effects of oil pollution on the marine environment will be an important consideration in energy policy decisions in the future. Public pressures and legal mandates, such as the National Environmental Policy Act and the Federal Water Pollution Control Act, will insure this. Changes in policies governing oil imports will affect the possibilities of accidental spills. International agreements concerning intentional shipping discharges will be formulated. Decisions will be made on where to allow offshore oil exploration and production, and on the types of pollution prevention technology required in these production fields. Superports will be planned, as will coastal refineries.
>
> At present, assessment of the environmental impact of such developments must be made in considerable ignorance and uncertainty because of large knowledge gaps and conflicting opinions. Because so many serious questions remain unanswered, and because of the alarming implications of some of the

information available, we recommend great caution in making policy decisions involving oil and the marine environment. Given the diverse and often equivocal evaluations offered by the scientific community, it falls to society to decide what level of confidence to place in available information concerning the consequences of oil pollution of the marine environment. Do we assume a pollutant is "innocent" until proven "guilty," as we have often done in the past? Or do we assume it is "guilty" until proven "innocent," as we currently do with drugs? Or shall we scrupulously avoid making assumptions and seek the full range of scientific information needed to arrive at well-considered judgments? [15]

To this one might also add, how long can we scrupulously avoid making these well-considered judgments? When, if ever, will the full range of scientific information be available? Judgments will likely have to be made on the basis of the best information available at the time and revised if better information is brought forth.

The surface of the sea, which was perfectly smooth and tranquil, was covered with a thick filmy substance, which when separated, or disturbed by any little agitation, became very luminous, whilst the light breeze that came principally from the shore, brought with it a very strong smell of burning tar, or of some such refinous substance. The next morning the sea had the appearance of dissolved tar floating upon its surface, which covered the ocean in all directions within the limits of our view; and indicated, that in this neighborhood it was not subject to much agitation.

—GEORGE VANCOUVER.[16]

SANTA BARBARA CHANNEL, *November, 1793.*

[15] Boesch, et. al., op. cit., p. 45.

[16] Some scientists maintain that the volume of oil released into the ocean environment from natural submarine seeps may be equal to the volume of oil entering into the ocean environment from tanker spills, blowouts and other man-made activities. See: R. D. Wilson, et al., "Natural Marine Oil Seepage", *Science*, Vol. 184, no. 4139, May 24, 1974, pp. 857–865. Other scientists, however, dispute this theory. They believe that there is good reason to believe that most oil in the ocean environment is the result of man's activities. See: Max Blumer, "Submarine Seeps: Are They a Major Source of Open Ocean Oil Pollution", *Science*, Vol. 176, June 16, 1972, pp. 1257–1258.

CHAPTER VI. SOCIOECONOMIC IMPACT OF OCS DEVELOPMENTS ON THE COASTAL ZONE

A. COASTAL AREA DEVELOPMENTS: DEFINITION

Under the Coastal Zone Management Act of 1972, "coastal zone" means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal states, and includes transitional and intertidal areas, salt marshes, wetlands and beaches. The zone extends in Great Lake waters, to the international boundary between the United States and Canada and, in other areas, seaward to the outer limit of the United States territorial sea. The zone extends inland from the shorelines only to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters. Excluded from the coastal zone are lands the use of which is by law subject solely to the discretion of or which is held in trust by the Federal Government, its officers or agents.[1]

B. THE IMPORTANCE OF THE COASTAL ZONE

The Coastal Zone is rich in a variety of natural, commercial, recreational, industrial and aesthetic resources of immediate and potential value to the present and the future of the nation. It is the area where most of the U.S. population lives, works and spends much of its leisure time. Whenever oil or natural gas is expected to be located offshore, the near-shore becomes the staging area for exploration of the continental shelf, and once oil is discovered, the coastal zone will need to accommodate some or all of the onshore developments related to offshore oil and gas production. Coastal estuaries and wetlands are also the most productive parts of the oceans, outproducing any other area on land and in the sea. The survival of the nation's ocean fisheries is closely tied to protection of the wetlands and estuaries which perform such an important role in the life-cycle of many fish species. Finally, coastal areas offer unique recreational aspects for more than half of the population of the United States which is concentrated in the coastal states.

COASTAL ZONE POPULATION GROWTH

Population in coastal states, and in coastal zones within those states in particular, has grown very rapidly, and is expected to grow even further in the future. In 1940, 107 million people, or 80.9% of the population lived in the 30 coastal states. In 1970, the population in those states had grown to 173 million, or 85.1% of the total U.S. population. Not all people in coastal states live within the limits of the

[1] See appendix for the complete text of the Coastal Zone Management Act of 1972.

immediate coastal area. In 1940, 40.7% of the American people lived in the 394 first-tier coastal counties, a figure which increased to 49.0% in 1970. Also in 1970, 42.57% of the industrial work force was employed in the coastal zone, which comprises only 8.58% of the land area of the United States.

Population growth trends are likely to continue in the coastal zone. One study indicated that by the year 2000, approximately 80% of the American people might be living within 50 miles of the Atlantic and Pacific coasts, the Gulf of Mexico, and the Great Lakes.[2] In addition to the people who are actually working and living in the coastal zone, the area is visited annually by millions of tourists, demanding facilities. Thus, even where the coastal zone is sparsely populated year around, it is subject to rising pressures of vacation community development.

Given the current and projected population concentration in the coastal zone, it speaks for itself that this extremely valuable multiple use area within the coastal states, be protected from haphazard development.

THE ISSUES

Problems related to onshore developments of the petroleum and petroleum-related industries are essntially problems associated with competing claims over the use of the coastal zone. Since many of the resources and natural amenities of the coastal zone are for legal and technical reasons common property, they are subject to the same misuse and potential destruction as other common property resources such as air and water.

Onshore industrial development related to offshore oil and gas production is one of the many activities exerting growing pressure on coastal lands. Second home developments, condominiums, hotels, boat marinas and other industrial and recreational facilities have mushroomed in the nation's coastal areas in recent years. The various conflicting uses of the coastal zone need to be balanced and resolved in order to serve today's economic and social needs without depriving future generations of the coastal values we cherish today.

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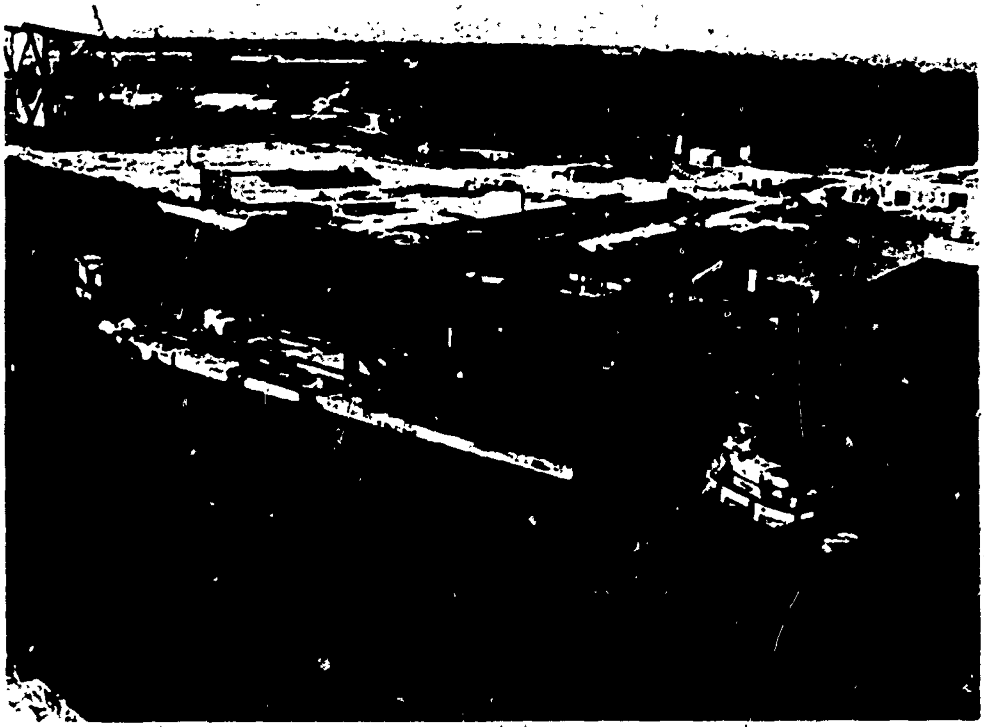
[2] National Journal. December 9, 1972.



Platform being towed from Louisiana yard out into the Gulf of Mexico

Coastal zone impacts of offshore petroleum developments can be subdivided into economic, environmental, land use, and social impacts. Environmental impacts related to offshore petroleum developments have been described elsewhere in this study (see chapter 3).

Actual socio-economic and land use impacts of OCS developments on the coastal zone will depend on a number of variables, such as:

1. Location of oil and gas fields.
2. Location of leased tracts in relation to shipping lanes, recreation areas, wildlife refuges, fishing grounds, and other potentially competitive users of ocean space.
3. Projected size of the oil or gas fields, estimated production rates, and type of production.
4. Geological, geophysical, economic and other data to indicate whether oil and gas are likely to be shipped ashore by tankers or transported by pipelines.
5. Projected size and location of onshore separation facilities, transfer pumps, and tank farms. Drilling rigs and platforms may be built in Louisiana and shipped to other areas or produced locally. Existing refineries may be able to handle offshore oil, which could be replacing imported oil. In other instances, additions to existing refinery facilities may suffice and there may be circumstances which warrant construction of new refineries. In sum, while certain onshore facilities will be required for all offshore petroleum developments, others are optional or independent from offshore operations.

Two examples may serve to illustrate the problems associated with projecting impacts of offshore oil and gas developments on the coastal zone. The first example assumes that oil companies find several very large accumulations of oil beneath the Georges Bank. The platform construction industry may find it more economical to build production platforms locally in New England, rather than constructing platforms elsewhere in the country and shipping them to Georges Bank. Once oil wells begin to produce, companies may initially transport oil from the platforms to the coast by tanker. As soon as sufficient oil has been found to warrant construction of a pipeline, which will probably stretch between 100 and 200 miles from the oil wells to the New England coast, oil will be transported by pipeline to newly constructed treatment facilities onshore. Instead of treating and storing oil in the costal zone, it is possible (at an additional cost) to pipe oil ashore to oil transfer pumping stations, from where oil will be transported by tanker or by pipeline to treatment facilities and refineries, elsewhere.

Refineries need to be close to a waterway, because of substantial water requirements for the refining process, but they do not necessarily have to be located in the coastal zone, even though it may be preferable for economic reasons. In view of the shortage of refineries in the Northeast (there are no refineries in New England), a large commercial discovery of oil on Georges Bank would certainly have some impact on decisions concerning the construction of one or more refineries in New England. Availability of feedstocks will also enter into the decisionmaking process concerning construction of petrochemical plants.

A second scenario assumes several small discoveries (but still commercially viable quantities) scattered over the Georges Bank area in relatively small stratigraphic traps. In view of the distance (100–200 miles) from shore, it may not be economical to lay a pipeline under those conditions. Instead, oil could be stored beneath (or close to) the production platform, where tankers will collect the oil and transport it to the mainland. The oil may be refined in existing facilities in the New Jersey/Delaware area, or elsewhere. Bringing oil ashore by tanker will limit required onshore facilities in New England, and could influence decisions concerning the construction of refineries and petrochemical plants. Also, pumping stations, gas treatment facilities, and other necessary onshore facilities under the first scenario, may not be required in New England under the second scenario.

In general, impacts of future OCS development are likely to be greater in the so-called "frontier areas" (areas where no previous oil and gas leasing has been undertaken) than in areas where onshore or offshore production has existed for many years. This is primarily due to the fact that in frontier areas new pipelines and new onshore facilities have to be built, new labor will have to be imported from oil producing states, and new relationships must be developed between the oil industries and other existing industries in the area that compete for resources. Also, impact of future OCS developments is likely to be greater in basically rural areas (such as Alaska) than in already heavily industrialized areas (Mid-Atlantic states), where multipliers relating direct to indirect effects will be significantly less.

Finally, the extent of the OCS impacts is dependent on the degree of primary and secondary activities undertaken in a region. Primary activities (direct impact) include all activities necessary to explore for and develop oil reserves. Included in this category are transports of supplies to drilling rigs, putting together of production platforms (which can be fabricated elsewhere), laying of pipelines, construction and operation of onshore treatment facilities, pumping stations and possibly LNG plants.

Secondary activities include development of industries which are a spin-off of the offshore petroleum developments. These include: refineries, petro-chemical products, platform construction yards and other industries related to the offshore oil industry. Secondary activities also include industries servicing those who are working for the oil industry, as well as the necessary public services such as schools, hospitals, police force, road building, housing, recreation facilities, and so on, to accommodate the influx of people drawn by expanding employment opportunities.

The socio-economic and land use impact caused by primary activities and public and private services connected with those primary activities can be minimized, but cannot be avoided entirely. Other industrial developments related to the offshore petroleum industry, such as refineries, petro-chemical industries and platform construction yards are independent from required offshore developments. Oil can be pumped ashore where it will be treated, and shipped by tanker or pipeline to refineries in other states (usually close to markets). Petroleum products will be shipped from refineries to final users and petro-chemical plants. Proximity to markets and labor force will be more important criteria for the construction of petro-chemical plants than adjacency to resources. Finally, unless concrete platforms are required, drilling rigs and production platforms can be shipped from existing yards to other parts of the world.

The states of Louisiana and Texas are examples of areas where all stages of the oil and oil-related industry have been developed, from manufacturing of drilling rigs used for petroleum exploration, to all phases of production, refining and product utilization in petrochemical industries. Hence, the impacts have been significant in terms of land use, employment created, government revenues from taxation and leasing payments from State owned lands, infrastructural expenditures, and so on. On the other hand, oil and gas produced in Alaska, an under-populated state with limited energy needs and few manufacturing industries, will be shipped by pipeline to ice-free ports such as Valdez. From there the raw material will be transported to California, Washington, and Oregon, where oil will be refined and petrochemicals will be produced. California and Washington are also likely to construct most of the drilling rigs and platforms to be used in Alaskan offshore exploration and development. Hence, impacts in absolute terms will be much less significant in Alaska than in either Texas and Louisiana, and much of the secondary impacts will instead be transferred to Washington, Oregon and California. However, in view of the small population in the State of Alaska and the very limited infrastructure in that vast area, actual socio-economic impacts are likely to be felt more in Alaska than in any other state in the union.

From the above it follows that socio-economic impacts related to offshore oil and gas developments differ greatly from region to region. Louisiana and Texas were already producing large volumes of oil and gas from onshore fields, and offshore exploration and production followed as a natural extension of onshore activities. The transition was gradual and took place at a time when people were less environmentally conscious than they are today. In view of the already extensive oil-related industrial developments in those states and the fact that much of the projected OCS developments there will replace onshore and nearshore oil production, any additional discoveries of oil off the coasts of Texas and Louisiana are not likely to cause very significant impacts. Socio-economic impacts on areas with little or no previous oil and gas developments will vary from marginal to substantial. The heavily industrialized states of the Mid-Atlantic are likely to be marginally impacted in case of a major oil or gas find beneath the continental shelves of the region. Additional industrial activity and population growth related to those developments is expected to be absorbed without undue constraints on existing resources. Impacts are likely to be somewhat more substantial in Southern California and the New England states. The South Atlantic states, and Alaska appear least equipped of all coastal regions with considerable petroleum potential, to handle the pressures of OCS developments.

Government service needs are difficult to generalize, but, as an example, Virginia is using the following ratios to describe increased public service demands attributable to population growth and industrial development:

School enrollment: 262.5 students/1,000 population increase.
Hospital beds: 3.64 beds/1,000 population increase.
Police: 1.54 police/1,000 population increase.
Government employees: 30 public servants/1,000 population.
Water demand-domestic: 100,000 gallons/1,000 population increase/day.
Water demand-refinery: 40 gallons/barrel of oil processed.
Sewage-domestic: 100,000 gallons/1,000 population increase/day.
Solid waste: 3 tons/1,000 population increase/day.

Alaska and other rural, non-industrialized parts of the country have difficulty adjusting to OCS-induced growth. The increased population caused by OCS development places the greatest strain on the infrastructure. New residents require more houses, hospitals, electrical energy, fresh water, police protection, sewer systems, which are difficult to provide especially in smaller communities without a major infusion of money. Frequently new roads, railroads, airports and port facilities are needed to meet the needs of the oil industry. This again requires vast outlays of front-end money, which cannot be recovered through taxation at the early stage of development when investments must be made.

Demand for labor related to OCS developments tends to follow a bell-shaped curve, i.e. a gradual increase in employment during the exploration and development stage until a peak is reached during the transition phase from the development to the production phase. During the transitional phase the construction industry will undergo a boom, when demand for treatment facilities, platforms, pipeline coating, gas processing plants, refineries as well as facilities and services to meet the needs of the growing number of people directly employed by

Source: National Oceanographic and Atmospheric Administration, Office of Coastal Zone Management. *Coastal Management and Aspects of OCS Oil and Gas Developments.* Rockville, Maryland, Jan., 1975, p. 35.

the oil, will grow rapidly. After the peak period, which may last for up to ten years, onshore activity will subside, because the operation phase just does not require as much labor as the construction phase. For example, it may take up to 2,000 workers to build a refinery, but only 300 to 500 to operate it. In major industrial areas construction labor can be shifted to other projects not related to the oil industry, but in rural, under-populated parts of the country, communities are frequently ill-equipped to handle the rapid growth followed by a declining economy. Local communities having borrowed a substantial amount of money to make infrastructure investments associated with demand during the boom period, may be faced with financial crises during the period of decline when employment diminishes rapidly but previous investments still have not been fully paid for. Only sound, long-term planning, can avoid future local and regional calamities of a financial, land use, aesthetic and social nature.

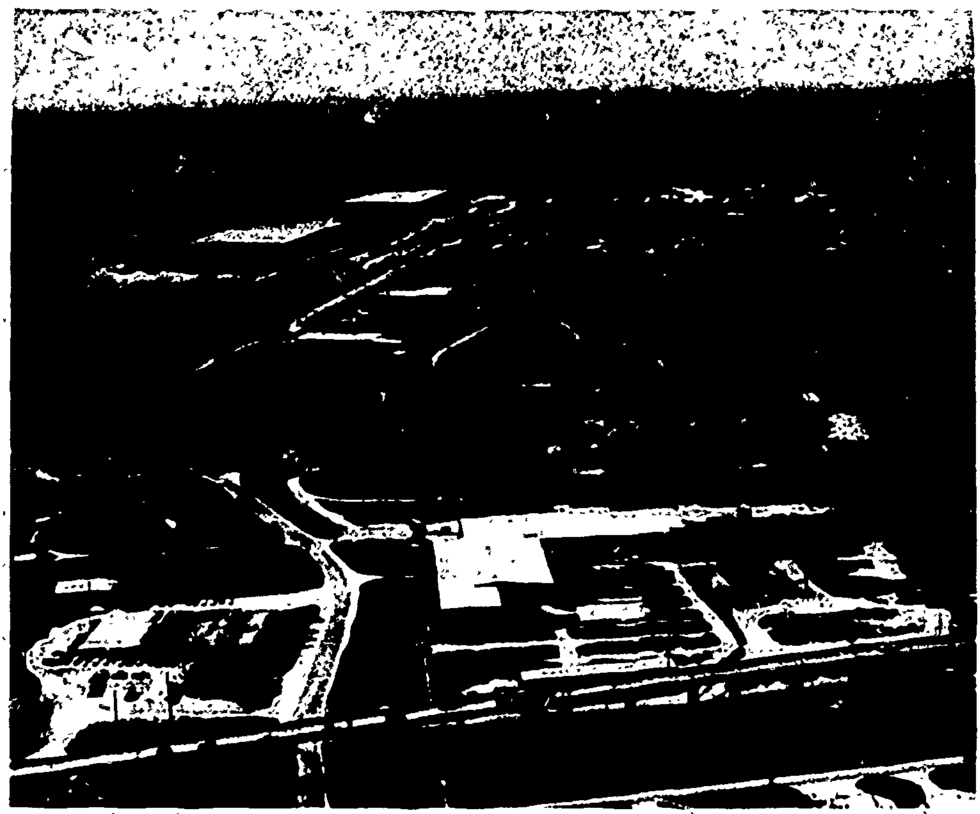
The influx of large numbers of strangers in small communities is also likely to upset traditional customs and lifestyles. Services may decline, schools and recreational facilities may become overcrowded, the crime rate may rise, and so on. These and other adverse social impacts are certainly not unique to offshore oil and gas developments but are part of 'boom-town' conditions. Only careful planning at the state and local levels will minimize adverse impacts, but it cannot be completely avoided.

Adverse impacts must be weighed carefully against positive national, state-wide and local benefits associated with offshore oil and gas developments. For example California, Massachusetts, Rhode Island and several other coastal states with offshore petroleum potential have unemployment rates higher than the national average. Even though the offshore oil industry is basically capital-intensive, development does provide thousands of local jobs particularly during the construction development phase. Depending on state and local tax systems, states and local communities stand to gain significant income from corporate and property taxes (see sub-chapter on California). Finally, offshore production of oil and natural gas will improve the energy supply situation of the coastal states and make them less dependent on more vulnerable foreign imports.

Nation-wide, development of offshore oil and gas will contribute to the aims of Project Independence, but the contributions of offshore petroleum are not likely to make the difference between energy independence and dependence on foreign imports. Oil demand in the United States by 1985 has been estimated at between 20 and 22 million b/d, of which a maximum of 11 to 12 million b/d is likely to be produced in the United States. Depending on the speed of leasing (gradual versus accelerated OCS leasing) and the degree of success in locating oil-bearing structures of commercial significance, total offshore oil (with the exception of Alaska) production estimates for the middle nineteen eighties range from 2.3 to 3.0 million b/d.[3] The lower figure would mean Business-As-Usual; the higher figure requires accelerated OCS development. In comparison, current offshore production totals slightly over 1 million b/d. Hence, even doubling of current offshore output of oil would provide no more than approximately 10 to 11% of

[3] Information obtained in private conversations with government and oil industry executives.

total projected oil needs by 1985. Total energy needs by 1985 have been projected at about 49 to 50 million b/d oil equivalent. Thus total offshore oil production would contribute 5% or less of total projected US energy consumption by 1985. Even the more optimistic projections of offshore production by 1985 requiring accelerated OCS development do not surpass 3 million b/d, which would be about 15% of US oil consumption, or approximately 6% of total projected energy consumption in 1985. The difference between business-as-usual and accelerated development in the OCS of the lower 48 states would be about 700,000 b/d in 1985, which would be about 6% of total oil consumption or about 1.5% of total energy consumption by 1985.



Platform Fabrication Yard at Morgan City

The McDermott Morgan City facilities are on 506 acres of land (including shipyard facilities)

Courtesy J. Ray McDermott & Co., Inc.

The Administration maintains that an accelerated OCS development program is of utmost importance, not because it will solve the nation's energy crisis, but an accelerated OCS development program together with accelerated development programs in coal, nuclear energy, synthetic fuels, advanced recovery techniques for conventional oil and gas development will result in making the nation less dependent on foreign sources of energy. Any significant shortfall in any one of the sources of supply will only increase dependence on foreign oil and natural gas. For a number of political, economic and national security reasons the Administration believes that any substantial increase of energy dependence is contrary to US interests.

FROM EXPLORATION TO PRODUCTION: ONSHORE IMPACT AT VARIOUS STAGES OF OCS DEVELOPMENT

The prime activity during the exploration phase is wildcat drilling. Employment per rig is slightly over 140 people; other people involved are dockside and service support, including transportation of crews and supplies to the drilling rigs. Outside the Gulf of Mexico area, many specialized jobs have to come from outside, but some local area skills (especially in the Mid-Atlantic) can be trained easily. Take for example the specialized tool and equipment supply firms. These service companies usually need only little land and generally employ no more than 25 persons. The actual size and number of operation basis required varies with the number and distribution of lease holdings, the number of companies with lease holdings, the amount of dependent activity, and the distance from onshore base to leased tracts. In addition to specialized services a number of unspecialized services such as welding shops, machine shops and cement companies, are needed to service the off-shore drilling rigs. These services can be provided locally, especially in industrial areas.

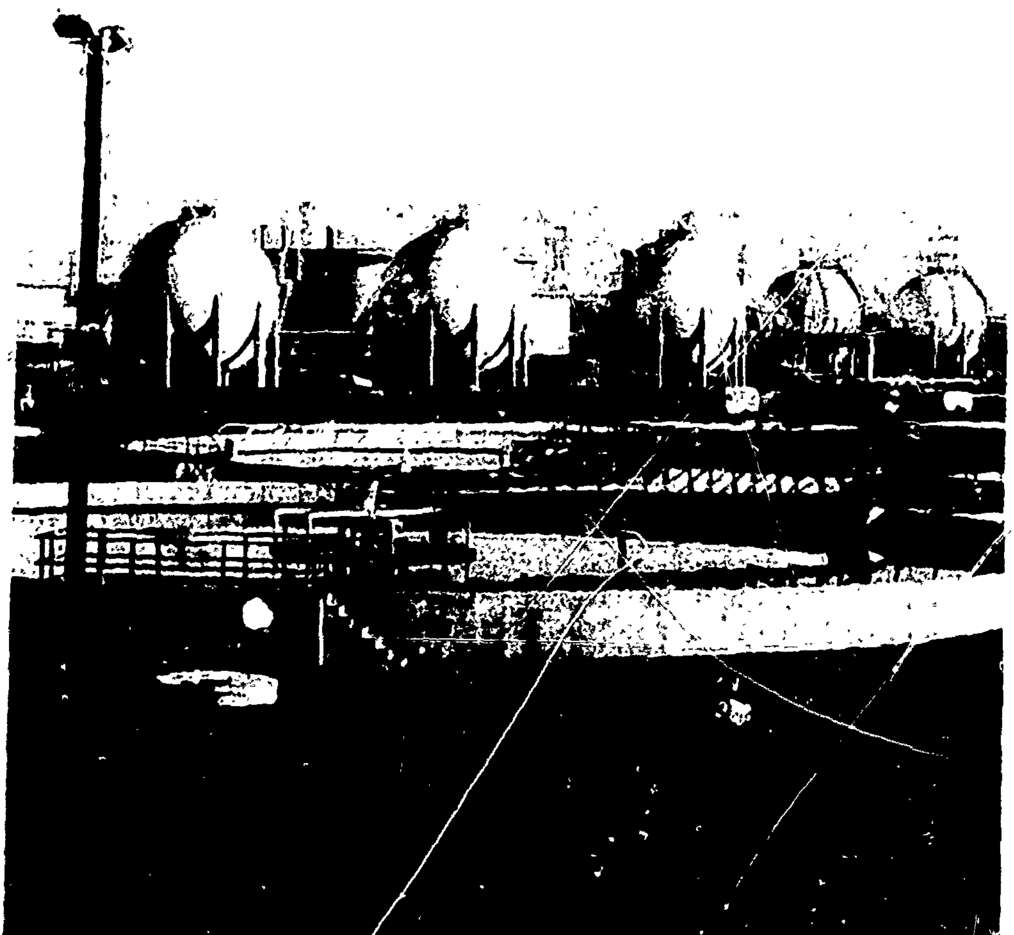
The exploration phase usually requires the largest number of non-resident employees, because of the temporary and specialized nature of the work. With the exception of Alaska and possibly the Southern Atlantic, rig workers and support company personnel are likely to be dispersed in the region where offshore development is taking place. In Alaska they are likely to concentrate in Anchorage. Spreading new employees and their families over larger areas diminishes potential adverse socio economic impact.

Initially, platform construction for frontier areas is likely to take place in existing construction facilities. At some point the volume of work may increase to the extent that locating a platform construction yard in the area of offshore activity may become profitable. It is preferable that facilities be located in industrial areas close to adequate land transportation. The yard must be located adjacent to an inland waterway that has unobstructed access to the ocean. The size of the yard depends on the design capacity, but an estimated 150–500 acres will probably be needed for a medium-sized yeard. A large yard can easily employ a few thousand workers or more. McDermott, one of the largest rig and paltform construction companies, employs about 2,400 people in Louisiana (at two major production yards). Most platform construction yards are much smaller and employ significantly less people. Construction yards are major industrial developments with significant impact on coastal zone development. Onshore separation facilities, treatment and plants, and, where needed tank farms will also be constructed during this phase, along with infrastructural projects and additions to public facilities for the growing population.

Drilling and Production: Once platforms have been installed and production of oil and/or gas commences, employment related to offshore development tends to decrease due to a considerable drop in construction activities. Production platforms require only small crews of about 16. Most crew members can be selected locally, because—with the exception of supervisory personnel—few special skills are required. In contrast with the exploration stage, the development stage is less mobile. Platform personnel from outside the region are expected to relocate to the action area.

Pipelines

Depending on the size, location, intended use and cost, pipelines are constructed and laid by several different methods. Some methods require more temporary coastal zone land use than others. Once the pipeline has been completed, little socio-economic impact can be expected. The number of people employed in operation, maintenance and repair is very small, and pipeline activities are not likely to affect land use, except to preclude certain uses within the right-of-way. This in turn can be limited by using existing utility or transportation corridors. Depending on regulations, pipelines can be buried both offshore and onshore, reducing the negative aesthetic effect (as well as reducing potential accidents) to next to nothing. British officials required that a pipeline from the Forties field in the North Sea would be completely buried beneath the sea-bed in the North Sea and onshore from Cruden Bay to the Grangemouth refinery. During the construction phase a ditch had to be dug, leaving some scars for a little over a year. Today it is impossible for the untrained eye to locate the site where the Forties field pipeline comes ashore (see pictures, p. 173).



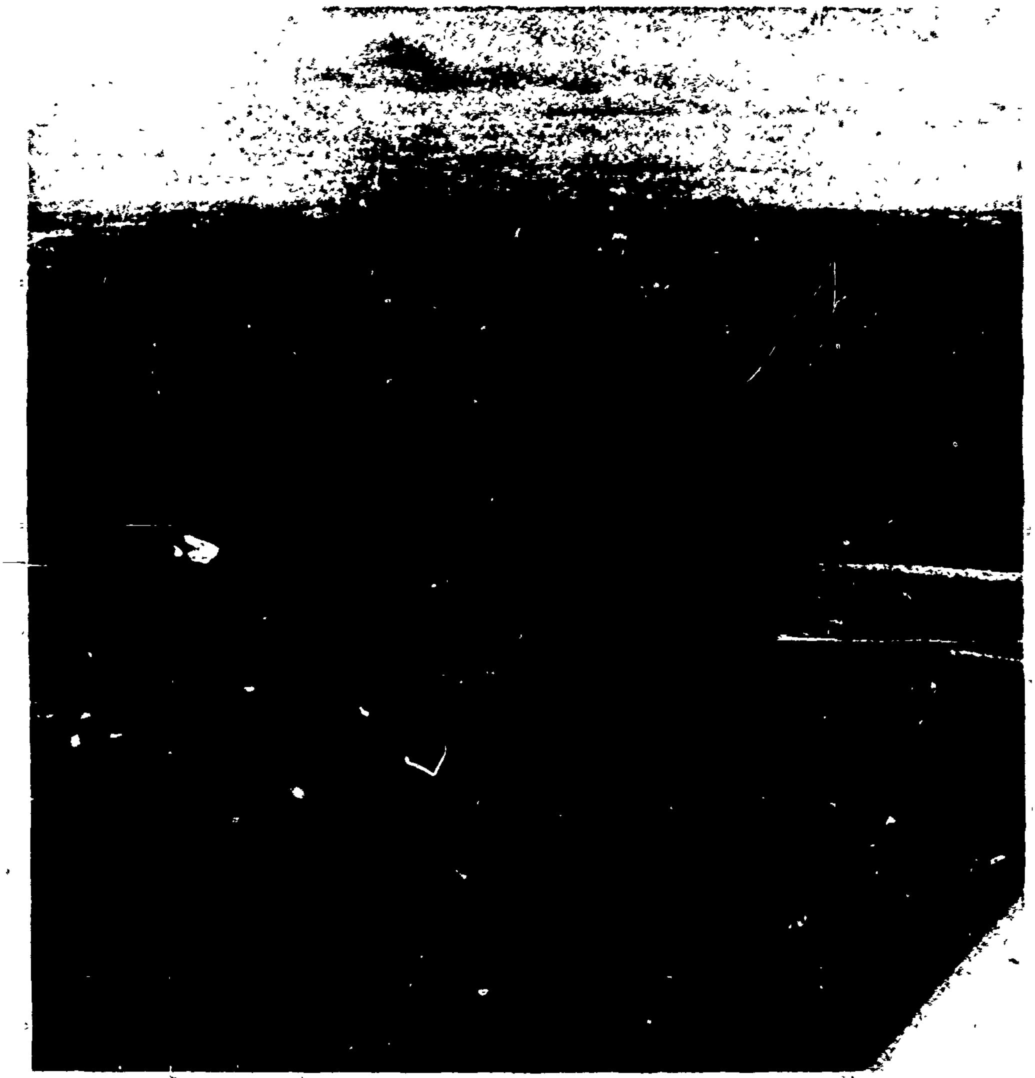
Water treatment facility at Exxon USA Bayway refinery, Linden, New Jersey
Courtesy Exxon Corporation.

Onshore, pipelines require pumping stations, and possibly storage facilities (tank farms). Tank farms could be built in the coastal zone, or if refineries are located further inland, they can be built close to the refineries. In that case only a pumping station is needed in the coastal zone. The pumping station, a small building, is generally located at a distance not too far from the coast. In the Cruden Bay area in Scotland, the pumping station cannot be seen from the beach. It is located about three miles inland. Oil is not stored near the coast, but instead pumped to a refinery in Grangemouth on the Firth of Forth. In the Gulf of Mexico, a terminal facility including a pumping station and storage tanks, is common. It should be emphasized, however, that it is not strictly necessary to place storage tanks either in close proximity to the pumping station or near the coastline. In some areas offshore oil may just replace imported oil, and no additional storage facilities may be necessary.

PICTURE 14

Aerial View of Cruden Bay, Scotland (Aberdeenshire), site of landfall of BP's submarine pipeline from the Forties field in the North Sea, immediately before the first section of the 32-inch diameter pipeline was winched ashore after being laid by barge (May 1973)

Courtesy: British Petroleum Company.



PICTURE 15

Aerial view of landfall of BP's North Sea oil pipeline from the Forties oil field at Cruden Bay, Scotland (Aberdeenshire), two years after reconstruction of sand dune system (Sept. 1975). Encircled area is the same as the area shown in picture 14.

Courtesy: British Petroleum Company.

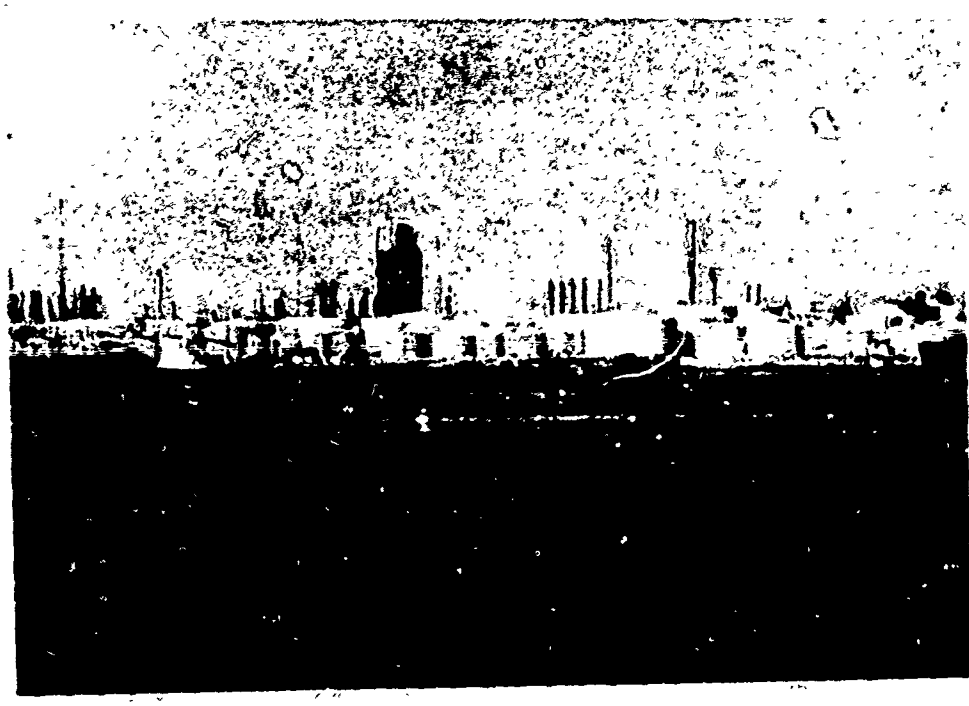
If refineries are very far removed from where oil comes ashore, companies may construct terminals to receive, store and discharge oil by truck, tanker or railroad cars. Terminals may need a few hundred acres of land depending on the storage capacity, and require hundreds of workers to construct. Upon completion, no more than about 100 people are needed to operate a terminal with a 2.5 million barrel capacity. Terminal facilities may include: storage tanks, docks, tanker loading and ballast treatment facilities, a power plant and vapor control facilities, an office building, fire pump building, and fire station, warehouse and shop building, and oil spill contingency equipment.

Among the terminal facilities, tank farms require most space. The actual amount of land needed depends on the required capacity of the tank farm and how the tanks are constructed. The diameter and height of the tanks could be adjusted either to reduce visual impact or to reduce the amount of land required. Wherever possible, tank farms should be sited along a corridor where they will be least obstructive and present the least conflict with other land use.

PROCESSING OF OIL: REFINING

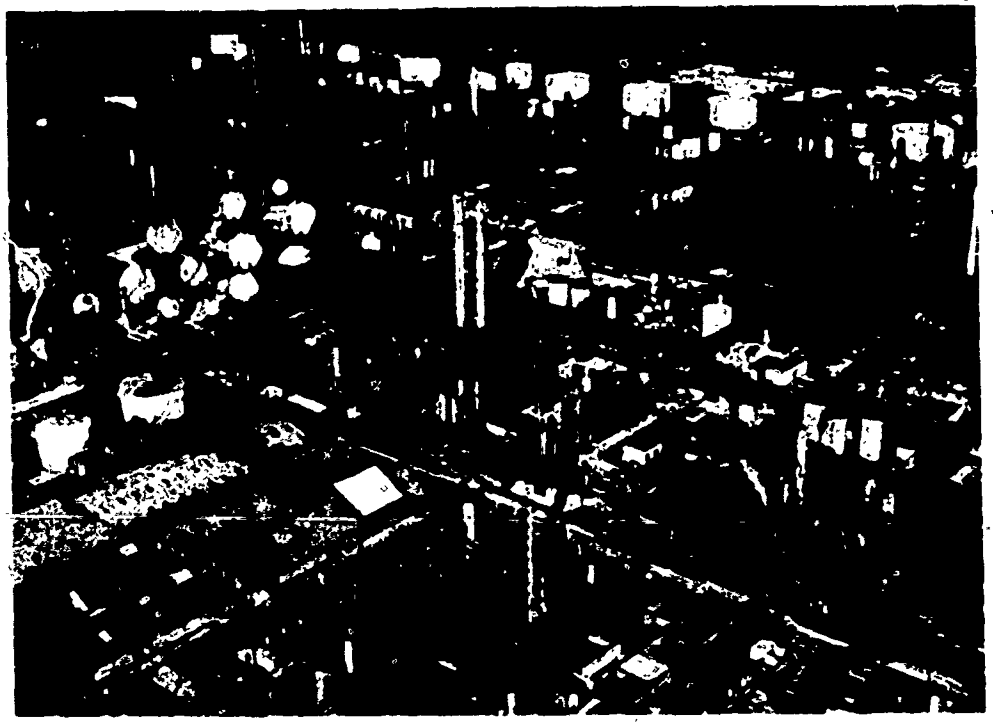
Refinery capacity has expanded rather slowly in recent years. Even though opposition to sitting refineries close to waterways (they need a great deal of cooling water) has hampered development, it is likely that additional capacity will be added in the next decade. Growth will occur whether the OCS is developed or not. In contrast to some previous studies on OCS Oil and Gas production, OCS development by itself is not likely to induce more refining capacity, in the aggregate, than would otherwise occur The economics of refinery siting has less to do with proximity to the source of crude than with proximity to markets for petroleum products and access to transportation networks.

It should be noted that although the economic advantages of accessibility to water coupled with shorter supply lines does make the coastal zone a prime target for refinery construction, it is possible to operate refineries inland, as long as adequate supply of water is available. Moving further land-inward may add to the cost of refining oil, because along with the pipeline itself additional pipeline right-of-way needs to be obtained, and onshore terminal facilities in the coastal zone may have to be constructed for transport of crude to the refinery.



Baytown Refinery, Texas

Courtesy Exxon Corporation.



Close-up of Baton Rouge refinery in Louisiana

Courtesy Exxon Corporation

A medium-size refinery with a capacity of 200,000 b/d would require about 650 acres (including storage tank space), but generally industry would purchase about twice as much land in order to provide room for future expansion and to create a buffer zone. A refinery of this size would probably employ approximately 500 persons. The process of refining oil requires a great deal of electricity. If no sufficient spare capacity is available, a new electric power plant may be needed to service the refinery.

Gas Processing Plant: Associated gas (gas produced with oil) and non-associated gas is transported from the production platform by pipeline to gas processing plants, which separate water from gas, take out other liquid components which are sold as LPG, and take out sulphur and other impurities. Subsequently, the methane is either pumped into the intra-state or inter-state pipeline system, or, if there are no pipelines in the vicinity (Alaska, for example), gas will be liquefied and shipped to the markets. Gas processing plants require little land and few employees. A small plant with a capacity of 150 million cubic feet per day, would require about 7 to 8 acres of land and 10 employees. A large plant with a capacity of 500 million cubic feet per day requires about 20 acres and 55 employees.

Aesthetic values:[4] Adverse aesthetic impacts frequently do not result in total loss of the resource such as people refusing to go to the beach because of a cluttered view, but rather, some unquantifiable de-

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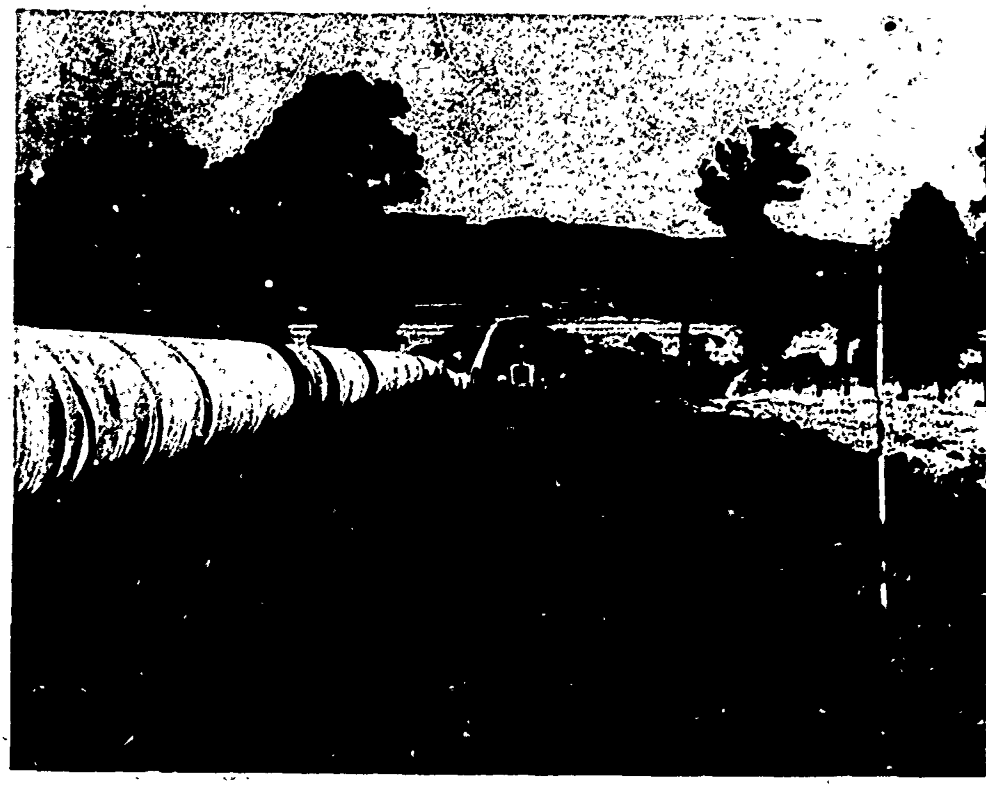
[4] See: "Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California," op. cit., p. 236.

preciation of their total enjoyment of the experience. Impact on aesthetic values will occur from both normal operations as well as failures such as oil spills. Visual quality is the most important aesthetic parameter, followed by sound, smell, and solitude. It is impossible to put a dollar value on aesthetics, because people's perception of what is aesthetic differs considerably. Loss of aesthetic values will be minimal during the drilling stage, causing no persisting or significant losses.



PICTURE 15a

Close-up of section of BP pipeline from Cruden Bay to the Grangemouth refinery in Scotland. (1973)

Courtesy : British Petroleum Company.

PICTURE 15b

Close-up of the same area as picture 15a, but taken in 1975, two years after the pipeline was laid

Courtesy: British Petroleum Company.

Onshore impacts during the exploration stage could entail land use change for equipment storage, heliports, communications and navigation equipment construction. Sensitive design, siting use of materials and landscaping could reduce the visual impact of the installations while road location, design and construction can be accomplished in a manner compatible with the terrain and hence be visually compatible. There is a distinct potential for some onshore loss of aesthetic values in localized areas due to these installations.

The risk of a blowout exists, even though blowout prevention mechanisms have improved substantially in recent years. If a blowout does occur, one may expect an adverse visual impact, the extent of which is dependent on the size of the spill and on the volume of oil reaching the beaches (see also p. 387 on effects of Santa Barbara spill in 1969).

Platforms will probably be constructed in heavily industrialized areas. If, however, platforms were constructed in what is now open area, the land use change involving dredging and filling plus the clutter of the structure itself and associated cranes would be a considerable impact.

Treatment and storage facilities can be placed on the production platforms, on offshore islands, in shoreline areas of the mainland, or further land inward. The placement of these facilities on offshore islands is said to constitute the greatest single impact potential in terms of alteration of natural regimes, thereby changing the aesthetic environment. Visual impact could range from high to low depending upon the sensitivity of siting, earthwork quantities, jetty construction, structure design, use of colors and subsequent landscaping.

Mitigating the aesthetic impact of offshore platforms are the cumulative effects of the earth's curvature, relative platform prominence and atmospheric phenomena on the visibility of a proposed offshore platform, which all act to diminish the possible visual impact of the structures.[5]

Onshore aesthetic impact depends on the number, size and location of treatment, storage, and supply facilities, on the need to build platform construction yards, refineries, petro-chemical complexes, LNG regasification terminals, and so on. Efforts are underway in the United States, Great Britain and other countries to mitigate the aesthetic impact by restricting construction of facilities to certain areas planned for industrial usage, by enforcing strict construction and operations regulations, and by official and private attempts to hide structures from observation (see pictures of tank farm, p. 172).

On the subject of aesthetic impact of offshore structures, a study by the consulting firm Dames and Moore concluded that it is largely a matter of subjectivity. Visual aesthetics is a difficult quality to assess. The determination of whether something exhibits a pleasant aesthetic character can become quite complex, as the very concept of aesthetics may have different connotations to different people. In the case of an offshore platform, a petroleum engineer might view it with pleasure, but a school teacher or farmer (although recognizing a certain functional beauty) may react in a negative manner to its overall aesthetic qualities.[6]

ATTITUDES OF REPRESENTATIVES OF COASTAL STATES IN FRONTIER AREAS

A few years ago, when less data were available on the actual and potential environmental and socio-economic impact of offshore oil and natural gas developments on the coastal zone, several coastal states voiced strong opinions against offshore petroleum development. There are still many state officials, particularly in local communities which expect significant adverse impacts from offshore developments and who oppose oil and gas exploration and production off their coasts. But most officials now seem to have moved away from total opposition to an attitude of favoring development, under certain conditions and appropriate supervision.

The House Ad Hoc Select Committee on the Outer Continental Shelf held regional OCS hearings in New Orleans, Los Angeles, San Francisco, Boston, New London (Ct.), Philadelphia, New York, Ocean City (NJ), Ocean City (Md), and Washington, D.C. The following coastal states views on offshore oil and natural gas developments were expressed, particularly by representatives from states where no previous OCS developments have taken place, and California, where offshore production caused adverse impacts during the 1969 Santa Barbara blow-out.

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[5] "*Critique of Bureau of Land Management: Draft Environmental Statement for Lease Sale 35*," op. cit., p. XIV.
[6] Ibid., p. 33

1. Coastal states are generally not opposed to offshore petroleum development provided it can be done in a cautious, prudent and orderly manner.

2. *Speed of Development:* Many coastal states are opposed to the haste with which the Department of Interior has been proceeding in leasing offshore lands. Coastal states want to complete their Coastal Zone Management plans, and be given sufficient time to evaluate the leasing programs proposed by the Department of the Interior. Mayor Thomas Bradley of Los Angeles, testifying before the House Ad Hoc Select Committee on the Continental Shelf in Los Angeles said that California wanted a "reasonable opportunity" to review the Interior's leasing program, * * * "not an unreasonable unconscionable delay, but certainly an opportunity in a timely way to listen, to read, to review, and then to react to the policy".[7]

3. *OCS and National Energy Program:* Representatives of coastal states have frequently expressed the need to review OCS development plans in light of a comprehensive, national energy policy. In testimony before the House Ad Hoc Select Committee on the Outer Continental Shelf, Thomas M. Downs, Executive Assistant to Governor Marvin Mandel, of Maryland, said that such an energy policy should be truly national and should be developed and implemented in partnership with the states, with full and early opportunity for public review and comment.[8] According to Mayor Bradley of Los Angeles, a national energy policy does not require yet another lengthy study, but a simple forthright public exposition of the basic elements of such a policy. It should consider the use of the OCS and other existing proposed oil resources in relation to our available coal reserves, and it should also take into account the role of energy conservation and alternative sources of energy.[9] Mayor Bradley maintained that the State of California was prepared to accept its responsibility, its part of the burden, in a national energy policy program.[10]

4. *State Consultation:* Coastal states want direct involvement by state and local governments in decisions to lease OCS tracts. David J. Bardine, Commissioner of the Department of Environmental Protection of the State of New Jersey testified that his State was not asking for veto power or even a mechanism based on delays of up to three years. What the Governor of New Jersey wants to insure is that he and other Governors of impacted states will have a real chance to know what is going on, and analyze the situations that they know more about than the Secretary of the Interior. They want true consultation and not lip service, so that the Governors will be able to convey their advice, their requests, and indeed, even their demands to the Secretary of the Interior.[11]

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[7] Testimony before the House Ad Hoc Select Committee on the Outer Continental Shelf. Los Angeles. August 2, 1975. See also testimony by Govenor Edmund Brown, Jr., and of the California Legislature. Los Angeles, August 2, 1975.

[8] Testimony before the House Ad Hoc Select Committee on the Outer Continental Shelf. Ocean City, Maryland, September 26, 1975.

[9] Testimony before the House Ad Hoc Select Committee on the Outer Continental Shelf. Los Angeles, August 2, 1975.

[10] Ibid., see also testimony of Eveile J. Younger, Attorney General of the State of California. Mr. Thomas M. Downs, Executive Assistant to Governor Mandel of Maryland made similar remarks on the role of OCS oil and gas in national energy policy making. see: Testimony before Ad Hoc Select Committee on Outer Continental Shelf, Ocean City, Maryland, September 26, 1975.

[11] Testimony before the House Ad Hoc Select Committee on the Outer Continental Shelf, Ocean City, New Jersey, July 25, 1975.

Mr. Bardine agreed with a policy which would provide for consultation with the Governors. The Governors would give the Secretary of the Interior advice, and the latter may reject the advice only on the basis of overriding national interest. He continued saying:

> Presumably the Secretary will try to avoid overriding the Governors as much as possible. In order to do that, he will instruct his subordinates to work with the State and local interests to try to come to an accommodation. That is what we are looking for, a reasonable, cooperative posture between the Federal interest and the state representing a more immediate interest, more concerned and responsible for the situation.[12]

5. *Separation of Exploration and Development:* Many state representatives have called for separation of OCS exploration and development. Coastal states want to review data in order to insure that development plans are consistent with coastal state Coastal Zone Management programs and other applicable state statutes and regulations.[13]

6. *Compensation:* Coastal states stressed the need for compensation for state financing of public facilities, for any adverse budgetary impacts, and for the costs of fulfilling state responsibilities in the regulation of offshore and onshore development.[14]

7. *Oil Liability Fund:* Coastal states favor compensation for oil spills without requiring proof of fault or negligence. Most state representatives called for an unlimited no-fault liability fund.[15]

Popular attitudes are generally in favor of OCS oil and gas development. Out of 30 nationwide and state survey responses to the question: Should offshore exploration be carried out, only one showed less than 50% of those surveyed in favor of drilling. Fourteen of the polls found more than 70% in favor of drilling, and 24 polls found 60% or more of those polled in favor of drilling. The 30 opinion polls were conducted by congressmen, state agencies and industrial organizations.

OFFSHORE OIL AND GAS DEVELOPMENTS

The Louisiana Experience

From the early developments of offshore oil and gas in the United States until today, Louisiana has outproduced all other coastal states together by a wide margin. Between 1954 and December 1974, Louisi-

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[12] Ibid. See also remarks by M. E. (Sherman) Webb, Executive Assistant to Governor Sherman W. Tribbitt of Delaware, Testimony before Ad Hoc Select Committee on the Outer Continental Shelf, Ocean City, Maryland, September 26, 1975; Testimony of Mayor Thomas Bradley of Los Angeles before the Ad Hoc Committee on the Outer Continental Shelf, Los Angeles, August 2, 1975; Testimony of Governor Edmund G. Brown of California and Evelle J. Younger, Attorney General of the State of California Before the House Ad Hoc Select Committee on the Outer Continental Shelf, Los Angeles, August 2, 1975. A few House Representatives have called for an outright State Veto on OCS leasing off their coasts.

[13] Testimony of Thomas M. Downs, Executive Assistant to Governor Marvin Mandel of Maryland Before the House Ad Hoc Select Committee on the Outer Continental Shelf, Ocean City, Maryland, September 26, 1975. At the regional hearings by the Ad Hoc Select Committee on the Outer Continental Shelf, need for separation of exploration and development was also stressed by Governor Edmund G. Brown of California.

[14] Testimony by Thomas M. Downs, Executive Assistant to Governor Marvin Mandel of Maryland Before the Ad Hoc Select Committee on the Outer Continental Shelf, Ocean City, Maryland, September 26, 1975. See also testimony by Edward F. Wilson, Coordinator of OCS of the State of Virginia Before the House Ad Hoc Select Committee on the Outer Continental Shelf, Ocean City, Maryland, September 26, 1975; and testimony by Mayor Thomas Bradley of Los Angeles, Governor Edmund G. Brown of California, and David J. Bardine, Commissioner of Environmental Protection of the State of New Jersey, op. cit.

[15] See testimony by Thomas M. Downs, Executive Assistant to Governor Marvin Mandel; Mayor Thomas Bradley of Los Angeles; and Evelle J. Younger, Attorney General of the State of California. Op Cit.

ana produced 4,497,360,000 out of a total U.S. offshore oil and condensate production of 6,572,703,000 barrels, and 29.4 TCF out of a total offshore gas production of 32.7 TCF.[16]

In spite of the disproportionately large volume of oil and gas produced from lands off the coast of Louisiana, few studies have been made on the onshore impact of offshore petroleum developments. Granted that Louisiana oil developments differ substantially from what we may expect in frontier areas in the Atlantic and Pacific OCS, the Louisiana experience is of great value to other coastal states in their efforts to plan for future onshore developments related to offshore petroleum exploration and production. A few studies will be contracted mostly by the Louisiana Coastal Resources Office, but it will take at least another year before such a study will be completed.

The little information that is available on onshore impacts suggests no serious adverse impact on most commercial and sports fisheries, or on tourism and shipping.[17] There is some evidence, however, that oil related developments have contributed to the destruction of 65,400 acres (out of 3,545,100) of wetlands in Louisiana, but much of the destruction ascribed to the oil industry was caused by development in the wetlands themselves rather than in actual offshore areas.[18] Dr. Gagliano of Louisiana State University's Center for Wetland Resources maintains that a major portion of the marsh destruction has resulted from actions of the petroleum industry, beginning in the nineteen thirties.[19]

It should be noted that at the time when much of the damage was done to the Louisiana coastal zone, the people were not yet aware of the potential adverse effects of dredging canals and filling of marshlands. The question of internalizing external costs has only been raised in recent years when man became more environmentally conscious. A Louisiana Coastal Zone Management Program emphasizing a balanced conservation and development policy of coastal lands, is in progress. Offshore petroleum developments may also have contributed to a decline in the Louisiana oyster industry, according to Mr. William Futtrell of the Sierra Club and Dr. David Wallace of NOAA.[20] Data on oyster production in Louisiana, however, do not agree with this view. In fact, oyster production in 1975 was higher than the 1950 production (see for detailed analysis chapter VII).

The state of Louisiana is among the first to admit that development of offshore petroleum resources is beneficial to the adjacent states in that it increases the number and types of jobs and leads to higher income levels. The state's prime concern is related to the fact that the benefits are offset, in part, by the costs of increased government facilities and services brought about by the influx of population and industry. In view of the fact that the state does not receive royalties for

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[16] United States Department of the Interior. Geological Survey. "Outer Continental Shelf Statistics, 1953–1974." Washington, D.C. June 1975, pp. 87 and 88. Louisiana's share of total OCS oil and gas production is even higher.

[17] See statement of Gov. Edwin W. Edwards before the United States House of Representatives Ad Hoc Select Committee on the Outer Continental Shelf, New Orleans, June 5, 1975, pp. 3 and 4, and p. 42.

[18] U.S. Senate. Committee on Commerce. National Ocean Policy Study. "Outer Continental Shelf Oil and Gas Development and the Coastal Zone." 93d Congress. 2d Session. Washington, D.C., November 1974. pp. 40 and 41.

[19] William Futtrell. "Oil and Trouble in the Louisiana Wetlands. Sierra Club. July/August 1974, p. 16.

[20] Ibid., pp. 42 and 43.

oil produced outside its area of jurisdiction, and is not in a position to tax the oil industry for offshore related oil developments due to Louisiana's taxation laws, the state maintains that the costs imposed on state and local governments outweighs the benefits. At the present time, the only taxes available to pay for these governmental services are collected by the state from inland operations and employees.[21] The state of Louisiana has called for a better distribution of the receipts of offshore developments and the costs of state and local government services.

Employment

Of a total of 49,685 persons employed in mining in Louisiana in 1971, Gulf South Research Institute estimated close to 18,000 work in offshore petroleum developments, and about 15,000 of these are working in OCS related activities. There is no estimate for total direct employment in all offshore mining activities, except for a reference in the appendix suggesting that perhaps as many as 75% of the 49,685 persons employed in the mining category "spend some time on offshore-related problems."[22]

Indirect employment related to OCS activities was estimated at 25,300, divided among four major industries: manufacturing, construction, chemical and allied products, and refining. In addition, the Gulf South Research Institute study estimated additional jobs related to the supply of goods and services to those directly and indirectly engaged in OCS petroleum development in Louisiana, at 84,100.

TABLE 7.—OCS-RELATED EMPLOYMENT IN LOUISIANA

Broken-down employment category	Estimated number employed as a result of OCS activity	Employees and dependents
Mining	15,000	47,150
Manufacturing	10,500	33,000
Construction	4,700	14,770
Chemical and allied products	7,300	22,940
Refining	2,800	8,800
Total	40,300	126,660
Supporting employment	84,100	264,330
Total	124,400	390,990

Source: "Offshore Revenue Sharing, An Analysis of Offshore Operators in Coastal States," prepared by Gulf South Research Institute, Baton Rouge, La., 1973, p. 46. For a detailed analysis of the methodology of the study, see app. B., pp. 1–6.

It is important to realize that: (*1*) the employment is related to an offshore production of 1.5 million bbl of oil and 3.8 tcf of gas light; (*2*) offshore oil developments in Louisiana began more than 30 years ago and still comprise more than 90 percent of total offshore output of oil and gas; and (*3*) because offshore developments grew gradually in Louisiana after years of onshore production. Secondary industries such as refineries and petro-chemicals grew with the expanded production. Industries servicing the offshore industry also expanded gradually. The existing services industry in Louisiana and Texas will be

[21] Gulf South Research Institute, "Offshore Revenue Sharing: An Analysis of Offshore Operations on Coastal States." Prepared for The Governor's Offshore Revenue Sharing Committee, Baton Rouge, Louisiana, 1974, p. 4. For a detailed analysis on state costs and revenue sharing, see chapter VI.
[22] Ibid., p. B-2.

able to meet much of the needs in other parts of the country, and consequently onshore secondary developments are not likely to grow anywhere near the size of the developments in Louisiana and Texas.

A survey of employment associated with offshore oil and gas development in Louisiana conducted by the Mid-Continent Oil and Gas Associated, produced figures slightly, but not significantly, lower:

Persons directly employed in offshore production	8,000
Persons directly employed in oil industry related area	30,000
Subtotal	38,000
Persons indirectly employed	76,000
Total	114,000

SOURCE. Mid-continent Oil and Gas Associates, "The Economic Impact of the Louisiana Offshore Oil Industry on the State of Louisiana," Baton Rouge, Louisiana, 1973.

For an analysis of the methodology used, see page 9 of the study.

Texas

From 1954 until 1974, Texas produced 29,272,000 barrels of oil and condensate, and 2.1 TCF of natural gas from offshore areas. The state of Texas is the fourth ranking offshore oil producing state in the country, following Louisiana, California and Alaska. Texas, however, does produce more offshore natural gas than either California or Alaska, but is outproduced by neighboring Louisiana.[23]

Offshore oil production in Texas reached its highest level in 1967/68, when 3.4 million barrels of oil were produced. Annual production in 1974 was 1.87 million barrels. Natural gas production from offshore fields peaked in 1971 at 387 BCF, declined sharply in 1972, and went up again in 1973 and 1974. In 1974, annual production reached 254 BCF.[24]

The Interior Department's proposed OCS planning schedule calls for large increases in the amount of federal lands offshore Texas to be leased for petroleum production. In the summer of 1975 federal leases off South Texas were put up for sale, and additional acreage will be offered in 1976.

Although Texas has been producing offshore oil and natural gas for more than twenty years, no major studies have ever been made on onshore impacts of offshore oil and natural gas exploration and production. In November 1974, the state of Texas produced an eight page study of the benefits and costs to state and local governments in Texas resulting from offshore petroleum leases on federal lands. It is so far the only available study on onshore impact of actual offshore petroleum production in the state and it is very limited in scope. The Texas Coastal Management office will have a design for a major study ready in 4 to 6 months, and expects a complete study on onshore impacts of offshore petroleum developments in 12 to 14 months.

The short cost-benefit analysis undertaken by the state of Texas last November, suggests that the costs of providing public service requirements to that segment of the population working for the offshore oil industry, outweighs the financial benefits that accrue to the state from federal OCS oil and gas leases.[25]

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[23] U.S. Department of the Interior, Geological Survey. "Outer Continental Shelf Statistics," op. cit., pp. 87 and 88.

[24] Ibid., pp. 87 and 88.

[25] Office of the Governor. Office of Information Services. Management Science Division. "Benefits and Costs to State and Local Governments in Texas Resulting From Offshore Petroleum Leases in Federal Lands," Austin, Texas, November 1974.

California

California is the oldest producer of offshore oil in the United States. The first production of oil from offshore fields was produced in 1896 in Santa Barbara. Prior to 1954 the State of California had already produced 422,385,000 barrels of oil from offshore lands, and between 1954 and 1974, the state produced 1,592,432,000 barrels of oil and 625 billion cubic feet of natural gas from offshore fields.[26] Today, offshore oil output in California is second only to Louisiana, but the State trails Louisiana, Texas and Alaska in offshore natural gas production. Offshore oil production peaked at 104,283,000 barrels in 1970, and offshore natural gas production peaked at 86.6 billion cubic feet in 1968. In 1974, California produced 81,638,000 barrels of oil and 30.2 billion cubic feet of gas, from 13 platforms and 42 subsea completion systems.

Like in Texas and Louisiana, no major studies have been conducted in the past on onshore development of actual offshore oil and gas exploration and production in California. In a letter to the Congressional Research Service, the executive director of the Californian Coastal Zone Conservation Commission, Mr. Joseph E. Bodovitz wrote:

> * * * Although there has been oil and gas production offshore of California for many years, there has been very little analysis done to date of either the environmental or socioeconomic effects of such activities. Interest in this topic has apparently grown only within the past two or three years, with the rapid movement by the Federal Government toward a major sale of oil and gas leases off Southern California later this year * * *.[27]

A study on the socio-economic impact of offshore oil and gas developments in California is in progress and may be completed soon. The study, prepared by the California Energy Resources Conservation Commission may provide some inside in past petroleum developments in the State of California.

A short study on the impact of oil production on Santa Barbara County was written by professors Walter J. Mead and Susan M. Wilcox of the University of California at Santa Barbara, in February 1973. The study emphasized revenue aspects, and concluded that the economic benefits of offshore oil development in Santa Barbara by far outweigh costs. Personal and corporate taxes related to the oil industry provided approximately $1,683,682 annually, while county expenditures generated by the offshore oil operations amounted to $3,900 only (primarily legal costs).[28]

Professor Mead maintained that the offshore platforms have no direct county fund requirements. Onshore supporting facilities require use of county properties, but do not generate large county expenditures. Police protection is limited to patrols which follow a set pattern so that observation of onshore facilities occurs, but no police activity directly related to the offshore petroleum industry is apparent. Fire protection on the platform is provided by the oil companies and Santa Barbara County fire services are only indirectly, if at all, required by the offshore operations.[29] Sanitation expenditures are a negligible

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[26] U.S. Department of the Interior. Geological Survey. Outer Continental Shelf Statistics. Washington, D.C., June 1975., pp. 87 and 88.

[27] Letter by Joseph E. Bodovitz, Executive Director, California Coastal Zone Conservation Commission, August 1, 1975.

[28] Walter J. Mead and Susan M. Wilcov. "The Impact of Offshore Oil Production on Santa Barbara County, California." Santa Barbara, February 1973, pp. 20 and 21.

[29] Ibid., p. 11.

expense to the county, and normal legal matters concerning oil companies may be considered as utilizing county supported juridical facilities, but only at a minimal level during normal offshore activities.[30]

Legal expenditures may increase significantly during a major oil spill. County expenditures increased by $57,000 during the Santa Barbara oil spill in 1969, and $45,000 out of this was spent on legal counsel and activities of the county supervisors. Because offshore operations in Santa Barbara had existed more than 11 years with no major spills prior to 1969, professor Mead estimated total annual cost per platform to the county at $300.[31]

Interaction with other industries: Tourism is one of the main industries of Santa Barbara county. During a spill tourists may stay away from the beaches, but normal offshore production does not result in excessive oil on the beach. Beaches around the world suffer from oil deposits in the form of small tar balls caused by activities in the oceans other than offshore oil production.

In Santa Barbara, the oil industry uses less than 15 boats, and cannot be assumed to cause congestion in the harbor. Sports fishermen visiting Santa Barbara may be encouraged by the apparent growth in the fish population near the platform structures.[32]

Professor Mead wrote that little effect on Santa Barbara County tourism as a whole was found in a 1972 study of the Santa Barbara spill, but a net loss of $150,000 was established as representing inconveniences and the necessity of some people to choose alternate (less preferred) vacation plans as the result of the oil spill.[33] Court settlements later returned $1,050,000 to motel and apartment concerns from oil companies in compensation for losses to those business during the oil spill.[34]

Offshore oil development was found to be beneficial to the Santa Barbara R&D industry, and interrelationships between offshore oil and other important sectors of the Santa Barbara County economy, such as the Vanderberg Air Force Base, agriculture, and the retirement industry, were considered to be limited if not non-existent.[35]

Commercial fishing takes place primarily beyond the channel area and are generally unaffected by offshore oil production during normal operations. Sports fisheries may have gained from platform construction, which has stimulated marine life in the area. During the 1969 oil spill, the commercial landing of fish at Santa Barbara was lower during the February-July period than during similar periods from 1965 to 1969. The greatest reduction occurred in February when the harbor was closed because of the oil spill.[36]

Aesthetic effects: Some 50% of the residential property in Santa Barbara (city) has some view of the ocean. Professor Mead maintains that evaluation of the aesthetic properties of any structure is made impossible by the varying individual conceptions of what constitutes an attribute and what is detrimental to the surrounding environment.[37]

[30] Ibid., p. 11.
[31] Ibid., p. 11.
[32] Ibid., p. 13.
[33] Ibid., p. 13.
[34] Ibid., p. 13.
[35] Ibid., pp. 14, 15, 16.
[36] Ibid., p. 15.
[37] Ibid., p. 19.

While the platforms are clearly visible at night and on clear days, the Economic Dimension of the controversy over the aesthetic aspects of the structures is lacking. Professor Mead argues that the platforms constitute visual structures in the Channel, but he attributes negligible loss or gain to the County due to their visual existence.[38] The study also points out that the structures serve as points of reference, and, on occasion, as markers for boat races.

Alaska

Through December 1974, the State of Alaska has produced 453,633,000 barrels of oil and approximately 464 billion cubic feet of natural gas from offshore lands. Offshore oil production in 1974 amounted to 55,970,000 barrels (it peaked at slightly over 70 million bbls in 1970) and 73 billion cubic feet of natural gas (peak production: 84 billion cubic feet in 1971).[39]

Some research on the socio-economic impact of offshore oil and gas developments in Alaska has been conducted by the State Planning and Research division of the Office of the Governor of Alaska. The study undertaken by the Governor's office looked at petroleum developments off the Kenai-Cook Inlet area, and attempted to measure the impact on the affected communities. Exploration began in 1958, the first natural gas was found in 1959, and petroleum production commenced in 1962. Between 1968 and 1971 an average of 170,000 b/d were produced from offshore fields in the Cook Inlet Basin.[40] The year 1968 was the peak year of activity in the development resources in Cook Inlet on the Kenai Peninsula. The population rose rapidly from just over 8,000 persons to nearly 14,000 in the years from 1965 to 1970. Employment rose from a low of just over 3,000 workers to nearly 8,000 workers in the period of 1965 to 1968 when a decline started at the rate of over 800 workers per year. School enrollments rose slowly until 1966 when there were 3,000 students, but increased rapidly through 1969 when there were 4,500 students. Thereafter, the enrollment has been slowly rising. The influx of people had an affect on property values in the Kenai borough, which rose from just over $100 million in 1966 to nearly $300 million two years later.[41]

The speed of the offshore development in the Cook Inlet area necessitated significant public investment within a short period of time. In the beginning of the period (1964), the Kenai Borough had only $6 million in public facilities, but by 1971 this value had risen to $24 million. The majority of the construction is directly attributable to the impact of petroleum development with its attendant needs for facilities and services for the industry. The $24 million included school construction, new public buildings such as the Borough Administration building, a maintenance shop, a warehouse and libraries as well as others. Over $255,000 was spent on emergency portable classrooms to temporarily accommodate the rapid increase in student population.[42]

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[38] Ibid., p. 19.
[39] U.S. Department of the Interior. Geological Survey. "Outer Continental Shelf Statistics," op. cit., pp. 87 and 88.
[40] Letter by the Director of State Planning and Research to the Attorney General and to the Commissioner of the Department of Natural Resources of the state of Alaska, April 15, 1974, pp. 1–3.
[41] Ibid., p. 4.
[42] Ibid., p. 4.

The Kenai-Soldotna area, which had a population of 810, expanded over 500% to a 1970 population of 4,735. In order to provide the necessary facilities for the expanded population, the city of Kenai had to borrow about $10 million during the boom years of the 1960's. The capital expenditures were made in the following functional areas: water and sewer expansion; public safety facilities (police and fire equipment, buildings, etc.); airport expansion and development; street and drainage upgrading and improvements; civic improvements (parks, small boat harbor, civic center, etc.)

The pros and cons of OCS compensation have been discussed elsewhere in this study. Suffice to say that the Governor of Alaska has stated that oil exploration and production in the Gulf of Alaska can be fully expected to cost virtually 40 cents in state public expenditures for each barrel of oil produced.[43] The state of Alaska is unique and its experiences are not likely to be relevant to offshore petroleum developments elsewhere in the Nation. Much of the population is concentrated in two cities with the rest of the people scattered over a number of small towns with limited local and regional infrastructure. Any major developments—offshore or onshore—are bound to have a significant socio-economic impact on the state. Recent experience with the construction of the pipeline from Prudhoe Bay to Valdez confirm this view.

Conclusion: Few studies have been made on the subject of onshore impact of offshore oil and natural gas exploration and production in those areas of the United States where actual developments have taken place. One would have assumed that prior to studying potential onshore impacts in frontier areas, the appropriate government agencies would have sponsored impact studies of actual offshore developments in Louisiana, Texas, California and Alaska. The few studies that have been conducted in recent years, have almost exclusively concentrated on revenue sharing aspects. Not a single major study, encompassing all aspects of onshore developments related to offshore oil and gas exploration and production in currently producing oil provinces, has so far been completed.

Hence, to measure potential onshore impacts, we have to rely on impact statements for recent and future leases, issued by the Bureau of Land Management, the Council of Environmental Quality, other government agencies, universities, State and local agencies, and private organizations and industries. In addition, we may be able to draw certain relevant conclusions from actual experiences and recent studies undertaken in the North Sea. Petroleum developments off the British coast, where no previous onshore or offshore oil production has taken place, may in fact be more relevant to frontier areas in the United States than experiences in the Gulf of Mexico, where a large onshore oil industry gradually extended its activities to near-shore and offshore areas.

NORTH SEA EXPERIENCE

The first major geological and geophysical studies on the British continental shelf were conducted in 1964, after the United Kingdom, Norway, Denmark and The Netherlands had agreed on the division of

[43] Statement by Alaska Gov. William A. Egan to the United States Senate Committee on the Interior and Insular Affairs, submitted May 10, 1974.

the continental shelf of the North Sea. Natural gas was discovered in the Southern part of the North Sea in 1965, and the first oil field was found in 1969 north of latitude 56° N. Until March 1975, 19 commercial oil discoveries and 15 significant gas and gas condensate discoveries had been made on the British continental shelf.[44] Natural gas production from offshore fields began as early as 1966; the first British offshore oil has been brought ashore in the fall of 1975. British estimates of proved and probably oil reserves in the North Sea are 2,265 million tons (16.5 billion barrels). Possible oil resources in the North Sea range from UK sector of the 22.6 to 32.8 billion barrels.[45]

U.K. Development Policy

Chronic balance of payment problems and the need to reduce dependence on foreign oil initially lead to the adoption of a North Sea leasing and taxation policy encouraging rapid development of offshore oil. The United Kingdom projected that by 1980 the country would be independent from foreign sources of oil, and may even become a net exporter of petroleum products during the early 1980s. Following the 1973 Arab oil embargo and the subsequent quadruppling of the price of oil, the then new socialist government of the United Kingdom reviewed the existing leasing and taxation procedures. The review process resulted in proposals which are not as favorable to the oil industry, and some observers maintain that the new proposals may retard North Sea petroleum development. Some oil companies even argue that the current proposals will result in abandonment of small- and medium-sized oil fields, which under the prevailing severe environmental conditions of the North Sea, may not be profitable to develop.

British attitudes toward offshore petroleum development has been very realistic. Suffering from severe unemployment in Scotland and chronic balance of payment problems, the British realized that the question was not 'if,' but 'how' North Sea oil and gas should be developed. Starting with the premise that offshore oil is desperately needed for the British economy, policy-makers then stressed what 'should' be done to safely develop offshore fields, rather than what should be done to halt or stagnate development. Scientists, public officials and civic groups did not advocate halting development until conclusive documentation would be in hand that no adverse impacts will occur. That is not to say that the British are less concerned about adverse environmental and socioeconomic impacts than people in other countries. They have in fact set aside vast areas in the coastal zone where industrial development (including onshore oil facilities) cannot take place at all, and in some instances—when environmental considerations were found conclusive—some projects have been abandoned.[46]

[44] United Kingdom. Department of Energy. "Development of the Oil and Gas Resources of the United Kingdom." London. 1975, pp. 27–33.

[45] Ibid., pp. 14 and 15.

[46] U.S. Senate. Committee on Commerce. National Ocean Policy Study. "North Sea Oil and Gas: Impact of Development on the Coastal Zone." 93d Congress. 2d Session. Washington, D.C., October 1974, p. 21.

In view of the recent shift in emphasis away from offshore in the direction of onshore impacts in the United States, it is of interest to note that offshore operations have received less attention from British planning authorities than onshore developments. While there are general and specific regulations on offshore structures and standards, in practice much of the offshore exploration procedures are based on agreements between the government and business.[47]

Onshore Planning and Development

The British have adopted an elaborate land use planning system to determine the best use of the land from the point of view of the community as a whole. Development must take place with the least possible damage to the environment and in such a way as to strengthen rather than weaken the social fabric of areas affected.[48]

A middle course is followed between the extreme attitude which would have nothing stand in the way of development, and the contrasting view which opposes virtually any change in the existing environment.

Planning procedure: Applications for onshore facilities in connection with offshore petroleum developments are entered in a register at the county level, which is freely available for public inspection. Sufficient information is provided to all interested parties early in the planning stage, enabling all interest groups to evaluate and respond to proposed actions. If the application proposes an action in accordance with the existing development plan and zoning regulations, the company can go ahead and build.

While county development plans are drawn up by local authorities, the central authorities, i.e. the Secretary of State for Scotland in case of plans concerning Scotland, have to approve the plan. The power of the central authorities is considerable. When a developer chooses a site for industry which is not zoned for industrial development, the Secretary of State for Scotland may decide to approve or reject the application depending on the findings of a public inquiry He may also make his approval conditional on certain points, such as the limitation on the size of the work force at the proposed site. Because of growing regional and national interests in the development of North Sea oil, government guidance on land use is increasing.

The Scottish Development Department made recommendations in 1973 to concentrate industrial development in 14 Preferred Major Development Zones for the east and southwest coasts. It also listed 23 Preferred Conservation Zones in which developers might be expected to encounter difficulties in obtaining permission to develop sites, and called for a West Coast Zone of high environmental quality where the development of individual small-scale sites may be justified, but where conservation should be predominant policy.[49] The report encouraged industrial development related to the oil industry to settle in the populated central belt of Scotland.

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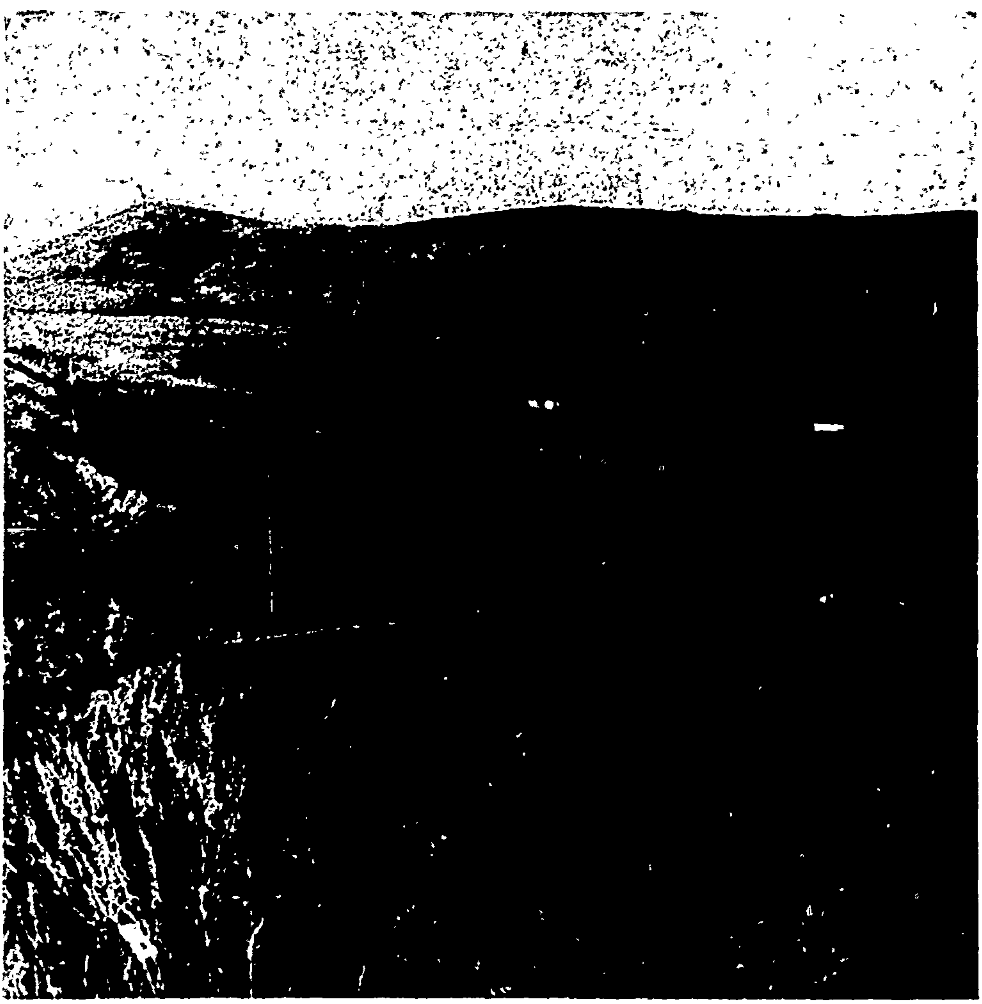
[47] Ibid., pp. 21 and 22.
[48] Ibid., p. 25.
[49] Ibid., p. 29.

Aerial view of the 500,000 ton (about 3.5 million barrels) crude oil storage installation at Dalmeny near Edinburgh, where oil from the North Sea Forties Field will be stored to await export from an island tanker terminal in the River Forth.



The same tankfarm seen from the highway and the countryside. The tanks and facilities have been completely hidden from view by landscaping them within a 100 year old spent shale tip system, one of the scars of the Sottish shale oil industry which flourished in the area from the 1850's. Over 2.3 million cubic yards of shale clay and topsoil had to be moved to construct a landscaped arena so that the tanks would be hidden from all corners of the compass. This was then seeded with grass and more than 50,000 trees were planted on the external slopes. More than $1 million were spent on landscaping the area.

Courtesy British Petroleum Company.

Onshore and Offshore Facilities Associated with Offshore Oil and Gas Development. The various Onshore Facilities in the Picture do not necessarily have to be constructed in the coastal zone, but can be moved land inward.

Companies interested in establishing onshore facilities in Scotland are assisted by the Highlands and Islands Development Board, whose task it is to advise interested industries on development opportunities, industrial sites, labor availability and financial assistance. It also receives the task to ensure that major changes resulting from oil development would take place as smoothly as possible and in such a way that they bring the greatest economic benefits to the local, regional and national economy, without impairing existing residents and industry.[50]

[50] Ibid., p. 28.

The British planning system appears to provide effective coastal zone land use and environmental protection. A few examples will serve to illustrate British success. The picturesque village of Drubuie, located on the northwest coast of Scotland, had been under consideration as a site for the manufacture of concrete platforms, but was rejected on the basis of unacceptable environmental and socio-economic problems. Following intense public opposition, the Secretary of State for Scotland, on August 12, 1974, turned down the proposal altogether on the basis of conclusive environmental considerations.[51] In another instance, when the British Petroleum Company applied for a site to construct a tank farm on a flat sandbank, local authorities allocated instead a former oil shale development site with huge tailings of spent shale which needed to be flattened first. The company was required to landscape the site upon completion of construction. From the highway, only landscaped slopes, seeded and vegetated, are visible. Within these high banks there are several full-sized oil storage tanks, each concealed from passerby (see pictures). The company had initially objected to incurring the extra expenses, but the final result serves as an excellent example of reclaiming a formerly scarred area. It also illustrated the power of local authorities to insist on development in an environmentally acceptable way.

A final example comes from Cruden Bay where a major pipeline from the BP Forties field comes ashore. Initially, the area where the pipeline comes ashore was scarred when the pipes were laid. Two years later, however, the area had recovered to the extent that there are no visible marks left. (See pictures, pages 176 and 177.)

Effects on Employment and Population Growth: The overall effect of North Sea oil and gas development on employment in Northeast Scotland and the Shetland islands has been significant. Impact on employment in the heavily populated areas of central and western Scotland (area of high unemployment), however, has been modest. In the first place, the oil industry is basically capital intensive and consequently demand for labor is not very high, and secondly, most of the oil-related industrial activities are on the east coast of Scotland and not in the populated major cities in the low lands.

Much of the industrial development related to the offshore oil industry will be near Iverness, Aberdeen, and a few smaller towns such as Peterhead. Iverness, for example, is expected to grow from 90,000 in 1971 to 140,000 in 1975; Peterhead may grow from 14,000 to 20,000 in just five years.[52]

The unprecedented growth is causing problems with schooling, housing, services and recreational facilities. For example, Brown and Root, a construction firm building platforms, initially anticipated hiring 900 employees. Actual employment, however, soon grew to 2,000. Housing and other facilities just could not be provided fast enough to meet expanded needs.

In view of the growing port activities related to offshore developments, harbor facilities in Aberdeen and in the smaller fishing towns of Peterhead and Dundee needed expansion. Highways, railroads, and airports in northeast Scotland became suddenly over-extended, and called for major improvements.

The historically high-wage oil industry also had an impact on other

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[51] New York Times, August 13, 1974.
[52] "North Sea Oil and Gas: Impact of Development on the Coastal Zone," op. cit. p. 13.

traditional industries in northeast Scotland and the Shetland islands. Skilled craftsmen in vital ancillary industries such as shipbuilding and repair have left their jobs and turned to oil-related industries where wages are higher. Some observers fear that the "boom and bust" frequently associated with the early stages of offshore petroleum development, could have negative long-term effects on the economy once the more labor-intensive construction phase comes to an end. Sound long-term planning will focus on efforts to attract petrochemical and plastic industries which use oil as a raw material. These industries could gradually replace the construction industry when the platform building phase comes to an end. Scottish authorities are making efforts to turn Aberdeen into the oil capital of Western Europe, providing goods and services to other countries after the boom associated with development of North Sea oil begins to taper off.

Shetland Islands:

The socio-economic impact of offshore petroleum developments on the population of the Shetland Islands will be substantial. Oil from many of the large and medium-sized oil fields in the northern sector of the North Sea will have to be pumped to and stored on the Shetland Islands, from where transshipment to the British mainland will take place. Moreover, the Shetland Islands may also become a major deep-water port, from where Middle East oil will be transshipped from VLCC to smaller tankers which can dock in most European ports.

Population has been estimated to reach 30,000 inhabitants in the early 1990s, instead of the 17,900 projected earlier.[53] The actual population growth will depend to a large extent on the construction of necessary and optional development projects related to offshore oil development. Between 600 and 1,500 jobs may be added in the next few years in oil related industries. This figure may be augmented by several hundreds of additional services related jobs. Demand on housing, health facilities, schools, recreation, other public and commercial needs will be substantial, and is certain to cause stress on infrastructure and on the social fabric of the islands. Only a few years ago a special study on economic and social conditions on the Shetland Islands indicated that the islands had a maximum absorptive capacity of 100 families per year without upsetting the social and economic balance.

Development of the North Sea oil is likely to have a significant impact on the traditional industries of the islands, such as tourism, fisheries, agriculture and textiles. Many workers will be attracted to the oil industry by higher wages, causing a decline in traditional employment. The Zetland County Council is worried about such structural changes in the islands' economy, because the islands would be left with one employer only, the oil industry. The danger of such a development would become evident thirty to forty years from now when the oil boom dies. In view of these projected developments, the Zetland County Council decided to apply for special parliamentary powers to reinforce normal planning and controls. In April 1974, the U.K. parliament passed the Zetland County Council Act of 1974, which gives the

[53] Ibid., p. 31.

Council the power: to act as a harbor and port authority, to license marine activities out to three miles, to obtain certain lands using condemnation if necessary and to create a Reserve Fund with oil related revenues.[54]

The Reserve Fund will provide, both during and after the oil era, the means for the County Council to take any steps which they consider in the long term interest of Shetland, the Shetland economy, or the Shetland community. This would include, for example, promoting the establishment of other industries which would diversify the economy and survive the oil boom, or safeguarding the position of Shetland's indigenous industries.[55]

Although one should apply extreme caution in attempting to compare developments on the Shetland Islands with potential developments in frontier areas in the United States, the Shetland experience does provide a case study which U.S. decision-makers should closely examine. In some coastal areas in the U.S. and in particular in Alaska, local conditions may be comparable to those in Shetland. In contrast to petroleum developments in the Gulf of Mexico, which expanded gradually from onshore to near-shore and the OCS, the Shetlanders are faced with a great many problems over a very short period of time, due to the speed of North Sea oil developments this is coupled with the fact that the islands had no previous onshore oil production.

Given the tendency in many circles today to focus on narrow local and regional energy problems only, it is refreshing to learn that popular attitudes on the Shetland Islands go beyond their narrow interests. Most Shetlanders do not feel they need the oil industry since traditional industries have thrived, and unemployment is low. Yet, the Shetland County Council recognized that certain of these developments were almost inevitable given the substantial national interest in the development of the North Sea oil resources and the strategic location of the islands. The underlying attitude on the part of the island leadership from the beginning was: "We don't need it; but if in the national good it must come, we want to be fully in control of all of the important decisions that involve the use of our land and water, the disruption of our communities, and the long-term well being of our people." [56]

The Shetland experience is a good example of a compromise between national energy requirements, and the need to control and manage onshore impact. The Shetlanders have developed a program that carefully guides and controls the location and environmental impact of needed new facilities that minimize adverse social and economic effects, and, at the same time, builds financial resources for strengthening traditional industries, especially for the post-oil era.

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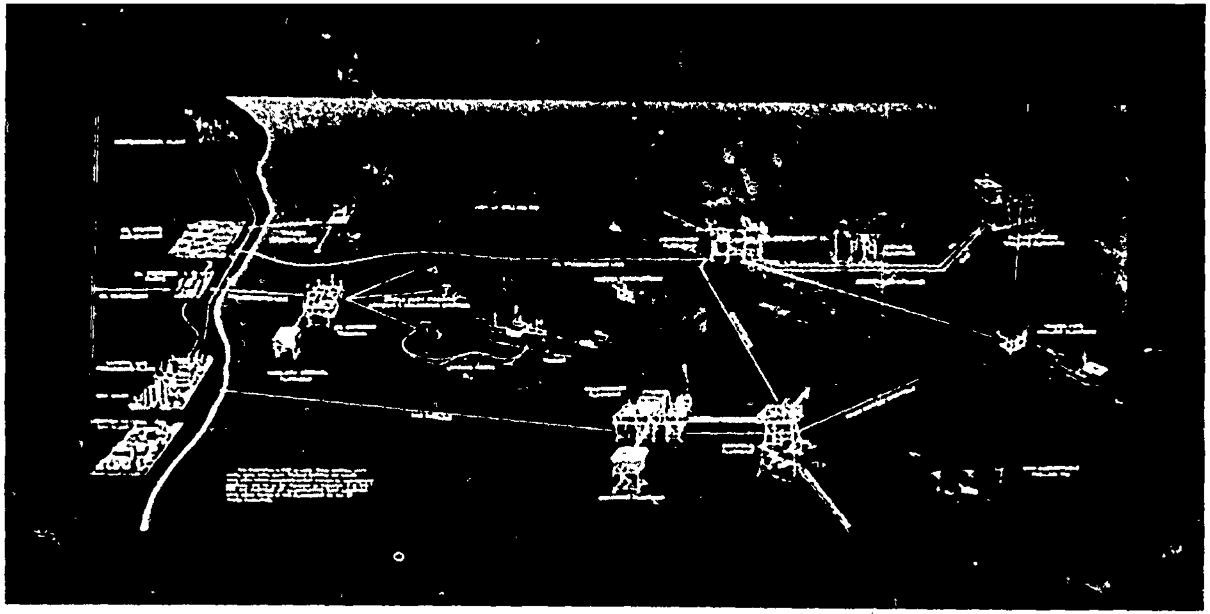
[54] Ibid., p. 36.
[55] Ibid., p. 36.
[56] Ibid., p. 34.



Schematic view of onshore and offshore facilities

ONSHORE IMPACTS: A REGIONAL ANALYSIS OF FUTURE OCS DEVELOPMENTS IN THE UNITED STATES

In recent years a number of significant developments have taken place in the debate over offshore leasing of Federal lands, and the effects of offshore oil and gas developments on the coastal zone.

1. Passage of the National Environmental Policy Act of 1969 necessitates preparation of an Environmental Impact Statement prior to leasing of offshore tracts for petroleum development. Paragraph 4332 C of NEPA states:

> The Congress authorizes and directs that, to the fullest extent possible: (1) the policies, regulations, and public laws of the United States shall be interpreted and administered in accordance with the policies set forth in this chapter, and (2) all agencies of the Federal Government shall— . . .
>
> (C) include in every recommendation or report or proposal for legislation and other major Federal actions significantly affecting the quality of the human environment, a detailed statement by the responsible official on—
>
> (i) the environmental impact of the proposed action.
>
> (ii) any adverse environmental effect which cannot be avoided should the proposal be implemented.
>
> (iii) alternatives to the proposed action.
>
> (iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and
>
> (v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.[67]

The prime importance of the Environmental Impact Statements for offshore mineral development leases on Federal lands, filed by the Bureau of Management of the Department of the Interior, is disclosure. Prior to the NEPA Act data on environmental and socioeconomic impact of offshore oil and gas developments were not readily available for consideration by State and Local governments. In addition to Environmental Impacts Statements issued by the Bureau of Land Management, the petroleum industry has in recent years issued several environmental impact statements, prepared by independent consulting firms. These data, combined with information gathered by academic institutions and State and Local government agencies, provide insight in projected offshore and onshore impacts associated with offshore petroleum developments of particular lease sales, which can prove to be very valuable in coastal zone planning.

2. The Coastal Zone Management Act of 1972: The impact of offshore oil and gas development and other industrial and non-commercial development in the coastal zone has taken on such dimensions, that planning of such activities and management of coastal zone resources has become imperative. Recognizing the urgency of the matter, Congress passed the Coastal Zone Management Act in the fall of 1972, and the President signed it into law on October 28 of that year. The Coastal Zone Management Act is designed to encourage coastal states to develop tools for the long-term planning and management of invaluable and irreplaceable coastal resources. For this purpose grant money had been authorized under the Act but funds were made available only in 1973.

None of the coastal states has yet approved a Coastal Zone Management Plan, but the State of California has completed its coastal

[67] National Environmental Policy Act, 42 U.S.C., 4321–4347.

zone plan. Hearings before the State Legislature have been held in December, and the California Legislature is expected to vote on the plan early in 1976. The next step involves approval of the coastal plan by the Secretary of the Interior. The significance of coastal zone management plans (once they have been adopted by the Secretary of the Interior) for offshore petroleum development can be found under section 307, and in particular under 307 (C-3), which states:

After final approval by the Secretary of a state's management program, any applicant for a required Federal license or permit to conduct an activity affecting land or water uses in the coastal zone of that state shall provide in the application to the licensing or permitting agency a certification that the proposed activity complies with the state's approved program and that such activity will be conducted in a manner consistent with the program. At the same time the applicant shall furnish to the state or its designated agency a copy of the certification, with all necessary information and data. Each coastal state shall establish procedures for public notice in the case of all such certifications and, to the extent it deems appropriate, procedures for public hearings in connection therewith. At the earliest practical time, the state or its designated agency shall notify the Federal agency concerned that concurs with or objects to the applicant's certification. If the state or its designated agency fails to furnish the required notification within six months after receipt of its copy of the applicant's certification, the state's concurrence with the certification shall be conclusively presumed. No license or permit shall be granted by the Federal agency until the state or its designated agency has concurred with the applicant's certification or until, by the state's failure to act, the concurrence is conclusively presumed, unless the Secretary, on his own initiative or upon appeal by the applicant, finds, after providing a reasonable opportunity for detailed comments from the Federal agency involved and from the state, that the activity is consistent with the objectives of this title or is otherwise necessary in the interest of national security.[58]

While particularly in view of the energy crisis the Secretary of Interior is likely to frequently invoke the national security argument whenever offshore leasing plans conflict with coastal zone management plans of coastal states, section 306 is a significant improvement over the situation prior to passage on the Coastal Zone Management Act, when no such provisions to protect coastal state interests existed at all.

3. Congressional action to re-write the OCS Lands Act of 1953 (S. 521 and HR 6218) and the Coastal Zone Management Acts Amendments of 1975 (S. 586 and HR 3981) (see Chapter 2 and pp. 230–233 of this chapter).

A careful analysis of OCS impact studies of frontier areas (Atlantic, Pacific and Alaskan OCS) shows two significant differences between the earlier impact studies, issued primarily prior to the middle of 1974, and studies released in the past 12 to 18 months. The former tend to emphasize offshore environmental impacts, and have much less to say about onshore environmental and socio-economic impacts. The latter, while still discussing in great detail the potential environmental impact in offshore areas, devote substantial space to onshore environmental and socio-economic impact scenarios. This reflects a shift in emphasis of coastal state concerns away from offshore environmental in the direction of preparing for coastal zone impacts. Secondly, earlier impact studies, in particular the 1974 OCS Oil and Gas study prepared for the Council on Environmental Quality, appear to have exaggerated

[58] 67 Stat. 462, 43 U.S.C. 1331 et. seq.

land-use and employment impact. CEQ data on job-creation and coastal lands needed to accommodate onshore facilities associated with offshore petroleum development are substantially higher than comparable data in the more recent regional impact statements issued by the Bureau of Land Management, private consulting firms and other national and state agencies and organizations. The following regional description of onshore impacts related to OSC oil and gas developments concentrates on the frontier areas of Alaska, California and the Atlantic seaboard.

Alaska

About 1.1 million acres of Federal OCS lands in the Gulf of Alaska are under consideration for leasing.* An Environmental Impact Statement (EIS) of the proposed lease sale has been completed by the Bureau of Land Management, and tracts are expected to be nominated The proposed lease sale of OCS lands in the Gulf of Alaska will be the first Federal offshore lease sale in Alaska. Originally 330 tracts were under consideration for leasing action, located offshore the northern Gulf of Alaska between Middleton Island and Ice Bay, in water ranging from about 30 to 200 meters depth. This number has since been reduced substantially. Prior to the EIS of the Bureau of Land Management, the Council of Environmental Quality released an OCS oil and gas impact study in April 1974. The CEQ report included sections of environmental and socio-economic impacts of Gulf of Alaska petroleum developments on the state.

The Bureau of Land Management EIS assumes that the proposed Gulf of Alaska lease sale will contain some 2.8 billion barrels of recoverable oil and 9 TCF of natural gas. Peak oil production has been estimated at 500,000 b/d; peak gas production at 1.0 billion cubic feet/day.[59] The 1974 CEQ report estimates a peak oil production of 750,000 b/d and 0.9 billion cubic feet of natural gas (high development scenario).[60] Actual production will depend on the size of the discoveries.

Both impact statements maintain that onshore impacts in the Gulf of Alaska area will have negative and positive impacts, and conclude that unless the capability of public officials to plan for and direct the onshore developments that are integral to OCS developments, the result could be permanent degradation of the environment and unnecessary disruption of traditional values and lifestyles for those living there now. The two studies also agree that onshore impact is likely to be limited to primary development (staging areas, oil treatment and storage facilities and services associated with these industries), and that oil and gas produced will be refined elsewhere.

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*Originally 1.8 million acres had been proposed, but in order to minimize environmental risks, secretary of Interior, Thomas S. Kleppe. Reduced acreage to be offered for sale to 1.1 million acres.

[59] U.S. Department of Interior. Bureau of Land Management. Draft Environmental Impact Statement Outer Continental Shelf." Proposed Oil and Gas Leasing in the Northern Gulf of Alaska." Anchorage. Alaska. 1975. p. 13.

[60] Council on Environmental Quality. "OCS Oil and Gas. An Environmental Assessment." Washington, D.C. April 1974.

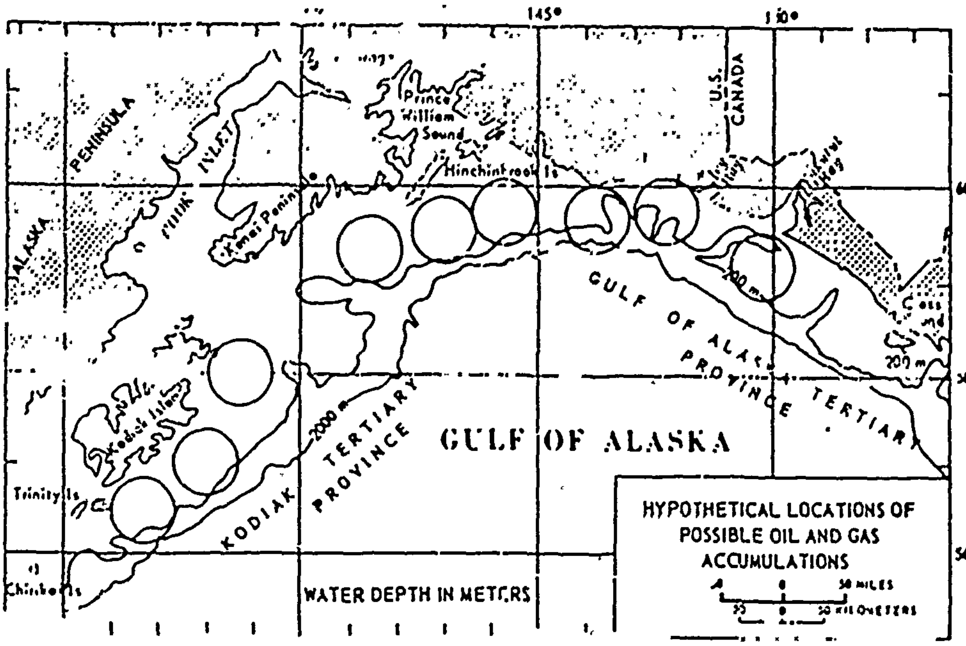

FIGURE 21.—Hypothetical Gulf of Alaska Oil and Gas Locations.

Source: CEQ. *OCS Oil and Gas-An Environmental Assessment*. Washington, D.C., April, 1974. p. 6–2.

Consequently, land use and population growth will be limited in absolute terms. Because of the small population of the towns surrounding the Gulf of Alaska, the limited infrastructure, and the already existing pressures on the existing infrastructure caused by construction of the Alaskan pipeline (in Anchorage and Valdez in particular), actual impacts are likely to be very substantial. Potential staging and transshipment areas are in the vicinity of Seward, Cordoba, Yakutat, Valdez, Katalla, Kodiak, Kenai, Homer and Anchorage. Outside the coastal towns where onshore treatment supply facilities will be located, Anchorage is likely to attract the bulk of the projected population increase.

*Land Use**

Although the state of Alaska is sparcely populated, land use can be a problem locally. In some cases, the topography of the region will preclude or limit the amount of land available for development. Another possible constraint in expanding existing land patterns is the present uncertainty of the land status under the Alaska Native Claims Settlement Act. The scheduled Gulf of Alaska lease sale may require a total of 1,055 acres of land for crude oil terminal, support and supply facilities, pipeline right-of-way, and a liquified LNG plant. The E.I.S. states that the most likely areas for operating bases might be Yakataga, Yakutat, Cordova, and Anchorage, as well as presently undeveloped sites. A crude oil terminal is possible in the vicinity of

*Land use figures quoted here and in the following sections on land use do not include oil refineries and petrochemical plant unless otherwise indicated. Land use figures quoted here and in following sections on land use do not include land use for housing and public services for employees of oil-related industries.

Icy Bay, and if an LNG plant is required, it could be sited in the vicinity.[61]

Secondary land use impact (demand for residential, commercial, public and quasi-public and open space lands) may encroach on existing land configurations and, in some cases, require extensive changes in land use patterns. Most of the secondary impact will center in the Anchorage area, but even a small demand for new dwellings and secondary services in the smaller communities could impact existing land patterns within these areas, according to the E.I.S.[62]

Impact on Transportation

The impact on the existing transportation system would involve: increased pressure on the land transportation mode should this system be used for the movement of heavy equipment to supply bases in the northern Gulf; increased demand on air traffic systems; and increased vessel traffic that would result from production and the associated oil pollution threat.[63] Harbor facilities in the proposed staging areas would need significant improvements, and additional harbor and docking facilities need to be constructed.

Employment

The CEQ report estimates that under the "high development" scheme, employment associated with the Gulf of Alaska lease sale will be around 4,400, and total poulation will increase by approximately 16,000.[64] The study by the Bureau of Land Management, which assumed an oil production of one-third below the CEQ average daily production, projects a population increase of 11,500 by 1984. After 1984 population associated with the Gulf of Alaska lease sale would gradually decrease. The study by the Bureau of Land Management shows that Anchorage will absorb 79% of the induced growth; the remainder being divided among the coastal towns.

During the first few years after the lease sale has taken place, employment will increase only slowly. The estimated personnel requirements during the drilling stage (based on the use of a maximum of 8 movable rigs and 8 on shore supply bases) are 296 workers for the first year, rising to 1,184 after three years of drilling activity. After the fourth year, personnel requirements for exploration drilling is expected to gradually diminish.[65]

About 60% of the personnel required during the drilling stage may be filled by Alaskans, who would work as floormen, roustabouts, mechanics, welders, workers in marine operations and catering services, radio operators, accountants, secretaries, work-boat crewmen, and helicopter men. A majority of the skilled personnel during the drilling stage will come from out-of-state. Because of the temporary nature of the exploratory stage, most of the out-of-state workers are not likely to become permanent residents in Alaska. Most employees working on the drilling rigs and the support facilities are likely to be housed in the Anchorage/Kenai area.

The next phase in offshore operation, drilling of production wells and production of oil and natural gas requires less labor than the

[61] "Proposed Oil and Gas Leasing in the Northern Gulf of Alaska." op. cit. p. 514.
[62] Ibid., p. 515.
[63] Ibid., p. 516.
[64] "OCS Oil and Gas, An Environmental Assessment," op. cit., p.. 7-70.
[65] "Proposed Oil and Gas Leasing in the Northern Gulf of Alaska," op. cit. p. 540.

exploration sta~~e. Total direct employment (onshore and offshore) at this stage has b..n estimated at 438 during the first year of development activities to a peak of 1,356 after five years of production.[66] Because many of the platforms workers will be needed during t..e life of the oil and gas production in workover operations and possible drilling of additional wells, most employees connected with the production stage are likely to establish homes in Alaska. Anchorage is expected to be the primary location of these families.

Employment related to construction of offshore and onshore facilities is expected to be smaller in Alaska than in other coastal areas of the United States. Unless concrete platforms are selected for use in the Gulf of Alaska, platforms are likely to be constructed somewhere else in the United States. Seattle, Portland (Oregon) and Vancouver have been suggested as potential sites for platform construction. Storage and offshore terminals are not expected to create more than 300 jobs during the peak construction year, the same number projected for pipeline installation. If LNG facilties need to be built, an additional 500 construction workers may be needed for a period of about two years.[67]. The construction industry in general is projected to remain one of the major growth industries in Alaska, due to the need for houses, schools and other facilities required by an increased population.

Construction activity within Alaska and along the Gulf of Alaska may provide a continuation of employment for workers presently engaged in the construction of pipelines within Alaska.

In addition to direct employment in oil and gas industry-related activities, the support sectors of the Alaskan economy are expected to create 1.75 jobs for every job in the oil/gas-related sector.

Total newly created direct and indirect employment related to the offshore developments in the Gulf of Alaska has been estimated to peak at about 4,727, earning about $70 million.[68]

Impact on other industries

A study by professors Mead and Wilcox of the effects of offshore development on the economy of Santa Barbara country, discussed elsewhere in this chapter, found that effects of offshore oil development on other industries has been negligible, even at the time of the Santa Barbara oil spill. In Alaska the timber industry is likely to receive an additional stimulus from the projected construction boom reelsewhere in this chapter found that effects of offshore oil development on other industries has been negligible, even at the time of the effects of offshore petroleum developments on fisheries. Experience in the Gulf of Mexico suggests that the construction of offshore platforms has been concurrent with increased fish catches of species of interest to sports fishermen. On the other hand, some observers maintain that cutting of channels, laying of pipelines, altering the currents has had an adverse impact on the oyster industry of Louisiana.[69] Offshore oil development might also interfere with fishing by reducing the acreage where platforms are clustered in rich fishing areas, and by causing damage to fishing nets caught in abandoned wells or debris on the ocean floor. On balance, there is no sufficient evidence to point

[66] Ibid., p. 545.
[67] Ibid., p. 549.
[68] Ibid., p. 568.
[69] "Outer Continental Shelf Oil and Gas Development and the Coastal Zone," op. cit. pp. 42 and 43. See also chapter VIII.

at the offshore petroleum industry as the source of any reduction in catch of coastal pelagic and demersal species.

The high-wage oil and gas industry could locally attract fishermen for work on platforms or onshore supply bases, possibly causing a net decline in total regional catch.

Local impacts of the Gulf of Alaskan oil development on infrastructure (both physical and social) could be substantial. The village of Valdez, the "Switzerland of Alaska," is already in the process of changing significantly, due to the Trans-Alaska pipeline development. The town is experiencing the same problems in the public and private services sector as other towns faced with very rapid development, but it appears that Valdez is better prepared to meet those challenges than many other villages. The Draft E.I.S. states that it is difficult to predict accurately whether or not the gradual decline in trans-Alaska pipeline inducements would not interface smoothly with OCS inducements, but concludes that it seems possible that the social infrastructure, physical facilities, and social support systems in Valdez, could be equipped and experienced to handle the possible OCS inducements. (Ibid, p. 505) The villages of Seward and Whittier would probably only be marginally impacted by offshore development in the Gulf of Alaska. Cordova on the other hand, would experience a doubling of its base population in case of "high development", which, in effect would create a new city. Housing and educational facilities would be particularly strained, the community hospital would have to be expanded greatly, and tourism would be adversely affected because of a shortage of motel facilities.

The greatest percentage of OCS inducements would affect Anchorage, which is presently experiencing heavy impacts in all sectors of life due to the influx of people working on the trans-Alaska pipeline. Development of OCS oil and gas in the Gulf of Alaska could add an estimated 9,000 people to the city's population by the middle 1980s. To service the growing population, substantial additions to existing public services will have to be made. The socio-economic effects of offshore petroleum developments in Alaska are probably not much different from other large industrial developments. Communities need to adopt creative planning strategies to cope with rapid development in order to take advantage of temporary boomtown conditions. The E.I.S. on OCS developments in the Gulf of Alaska refers to studies of Wyoming experiences of the boom phenomenon related to oil development in largely rural-oriented parts of the state (e.g. Newcastle, Cheyenne, Laramie, Hanna, Salt Creek, Casper, Gilette, Rock Springs, Douglas): "There has been little change in the social consequences over the past one hundred years . . . Divorce, tension on children, emotional damage, and alcoholism were the result. The pattern of depression, delinquency, and divorce was so well documented that the consequences were predictable." [70]

If Yakutat were chosen as a staging area to service offshore platforms, the influx of non-native workers in this small community could affect fundamental customs and marriage patterns, and could increase the pressure to let the native language die. Yakutat with its primarily native population is unique in this respect, and should not be compared

[70] bid., p. 511.

with Valdez, Seward or other potential staging areas. On the other hand, the CEQ report maintains that Yakutat is economically depressed, and that the population looks forward to the entrance of new industries, provided the local population will benefit from the activities.[71] The CEQ report also states that Yakutat does not have the financial resources to provide additional services required to accommodate additional population. Substantial influx of capital would be needed to provide even a minimum of community services for an expanded population.

Both the CEQ report and the Bureau of Land Management's EIS agree that Valdez and Seward are better prepared to serve basic population needs for an expanded population associated with offshore developments than Cordova and Yakutat. However, with the possible exception of Valdez which is continuing to expand its infrastructure and basic services rapidly to meet the needs of the population influx related to the Alaskan pipeline, all other coastal towns in the Gulf of Alaska will need a great deal of preparation and financial assistance to prepare for potential population increases associated with offshore petroleum developments.

In Alaska, more so than in any other, the influx of labor from out-of-state will have a significant social impact. Already, the publicity of well-paid job related to the construction of the Alaskan pipeline has resulted in attracting more out-of-state labor than are needed, causing additional unemployment in Alaska. Wages are kept high in spite of this, because the entire pipeline construction is unionized.

The economic boom caused by the pipeline construction has been a mixed blessing to local Alaskans. On the one hand, business is better than ever before, with $3 million in wages pumped into the local economy every week. Offshore oil and gas development in the Gulf of Alaska are expected to create additional wealth in the State of Alaska, which will benefit the entire population. On the negative side, the speed with which development is taking place has caused a number of problems associated with "boom-town" development. For example, the influx of people has fed inflation, and caused a severe housing shortage. Services are deteriorating, air pollution is on the rise, and in general the quality of life in Anchorage has come down. Although state and local police services have expanded substantially, the crime rate has increased significantly, particularly larceny and vice, but also violent crime. Schools in several Alaskan towns had to go on double sessions to cope with vastly increased school populations. In Fairbanks alone, the school population is expected to grow from 8,000 in 1973 to 12,000 in 1975.[72]

Onshore socio-economic impact related to offshore petroleum development in Alaska are unique, and should not be compared with potential impacts in other parts of the coastal zone in the lower 48 states.

California

Oil production in California reached a volume of 917,000 b/d in January of 1974 (peak production was 1,022,000 b/d in 1968), of which 235,000 b/d or 26.6% was from offshore fields. Of the total production

[71] "Oil and Gas, An Environmental Assessment, op. cit. pp. 7-42 and 7-44.
[72] New York Times, July 25, 1974.

186,000 b/d were produced from Federal lands, and 51,000 from OCS lands.[73]

The first barrel of oil from offshore fields was produced off Santa Barbara in 1896, with the extension of the Summerland oil field Santa Barbara was also the first area in California where Federal OCS lands were leased, following the decision by the US Supreme Court in United States vs California (1965), which decreed that areas of the Santa Barbara Channel lying seaward of three geographic miles from the Californian mainland and the Channel Islands would be under Federal jurisdiction. New leases were issued in January 1967. After the 1969 blowout in the Santa Barbara Channel, the Secretary of the Interior ordered the suspension of all drilling and production on Federal leases in the Santa Barbara Channel. These suspensions affected six leases on which drilling and production operations were in progress, and were lifted in June 1969.

On December 11, 1975, the oil industry offered a total of $438 million for 70 tracts of OCS lands in Southern California. In spite of efforts by the State of California and various local groups to postpone leasing of OCS lands in Southern California, the Interior Department offered 231 tracts (instead of 297 proposed earlier) to the oil companies. The lease sale which had been postponed from October to December covered about 1.5 million acres is the fourth offshore oil and gas lease sale on Federal lands in California, and is adjacent to one of the most populous areas of California in the coastal counties from Ventura to San Diego.

The U.S.G.S. has estimated the oil potential of the leased area at 1.6 to 2.7 billion barrels, and the natural gas potential at 2.4 to 4.8 TCF, and industry estimates have been as high as 6 to 19 billion barrels of oil and 12 to 38 TCF of natural gas.[74]

On an originally offered 231 tracts (1.3 million acres) by the Department of the Interior, oil companies and a Southland citizens group bid on 70 of the tracts. The Department of the Interior accepted offers on 56 tracts. Accepted bids totalled $417 million instead of the $1 to $2 billion the Secretary of the Interior had expected to net.

Areas affected by the lease sale are: San Pedro Bay, Santa Monica Bay, Santa Rosa Cortes, and Santa Catalina.

The actual onshore impact will depend on the volume of oil and gas to be discovered within the leased area. On the basis of various resource estimates, the number of platforms required to develop the resource ranges between 18 and 60, producing an estimated 110,000 to 960,000 b/d of oil over an estimated 40 years.

Land Use: It is questionable whether existing pipelines will be adequate to handle any increase in production in Southern California. If not, additional pipelines need to be constructed for about 100 miles in the same corridor. The earth removed in the operation will be replaced upon completion, and vegetation replanted at the construction site. Some land needed for the pipeline rights of way will establish a long term development barrier by prohibiting future building.

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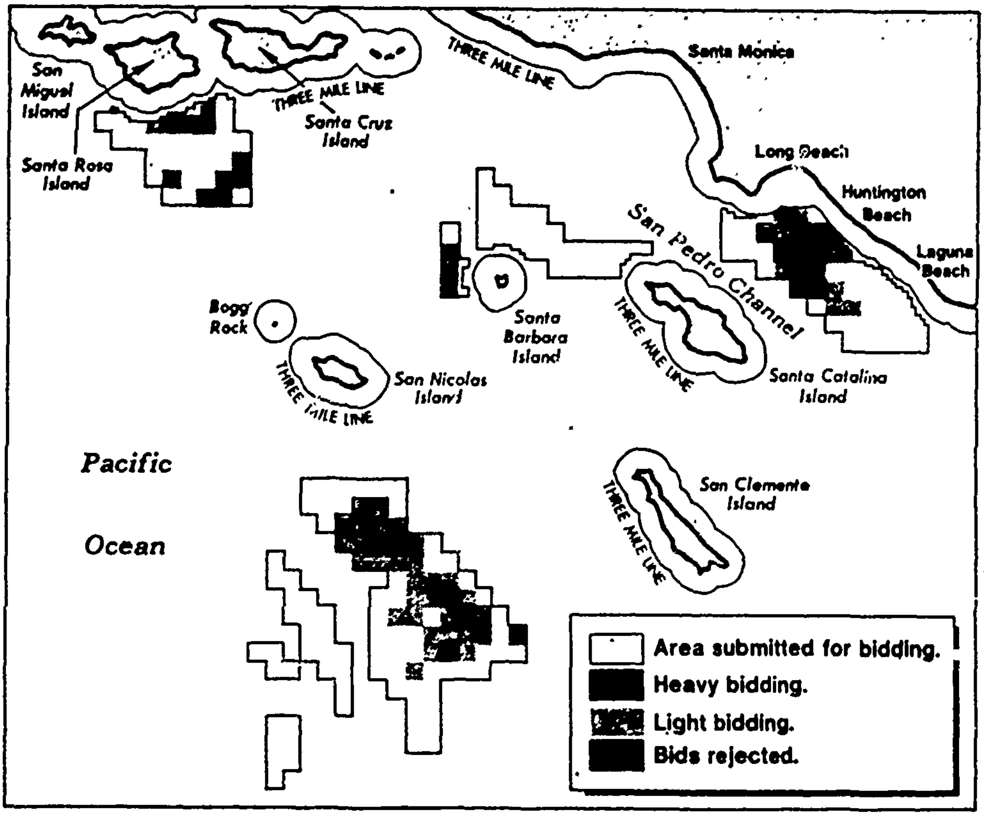
[73] U.S. Department of the Interior. Geological Survey. Draft Environmental Statement. Volumes 1–3. "Oil and Gas Development in the Santa Barbara Channel Outer Continental Shelf Off California. Washington, D.C. 1975. p. II-3.

[74] U.S. Department of Interior. Bureau of Land Management. Draft Environmental Statement Vol. 1–4. "Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California." OCS Sale No. 35. Washington, D.C. 1975. p. 1. and Western Oil and Gas Association. "Environmental Assessment Study—Proposed Sale of Federal Oil and Gas Leases, Southern California Outer Continental Shelf. Volume 1. Summary and Conclusions. Call Los Angeles. October 1974. pp. I–12 and I–13.

Los Angeles Times, Dec. 20, 1975.



OIL LEASES—Bids were accepted for areas marked light, heavy bidding. Others were rejected.
Times map

The EIS of the Bureau of Land Management estimates that three oil onshore terminals, one gas terminal and one additional refinery will be necessary during the development stage. The Corps of Engineers has reported that there is a shortage of sites for new refineries within the Los Angeles area basin, which means that a new refinery if necessary will probably be located to the north, in Ventura county. The EIS estimates that abou 1,000 acres of land will be needed for the onshore facilities, and that much of that land will probably be taken from existing farmlands.[75]

The 1,000 acres estimated in the Bureau of Land Management study includes the construction of a refinery. Previously, this study has indicated that refinery construction is not directly related to offshore oil and gas developments. If additional oil for Californian consumption were to be imported from Alaska or from foreign countries, oil would probably also have to be refined in California. Refinery development is related to demand for products and not so much to supply of crude oil. The study undertaken for Western Oil and Gas Association does not include refinery development in its onshore land use assessment. Their study estimates the following impact on the coastal zone: 200 acres of oil terminal and supply operations (including 65 acres of harbor and wharfage); 6–8 pipeline corridors containing up to 400 miles of line; approximately 145 vessels for supply, transport, clean-up and other purposes; 1 LNG regasification terminal (which can also be used for

[75] "Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California," op. cit. p. 272.

Alaskan and other LNG); some industrial land during the construction phase (but not necessarily in Southern California) for fabricating platform sections (probably in existing drydocks or shipyards).[76]

The reason for the rather modest proportions of the onshore land use impact associated with the recent Southern California OCS lease sale is related to the fact that much of the infrastructure necessary for the development of offshore oil and natural gas is already in existence in Southern California.

Employment

Economic activities related to the Southern Californian OCS lease sale will provide additional jobs in the area. During the initial exploration stage, when only a few hundred workers are needed, an estimated 85% will come from places other than Southern California. However, the percentage of Southern Californians will grow rapidly during the more labor-intensive development and production phases. It has been estimated that 65% of the new jobs during the development stage, and 80% during the production stage, will be filled by locals.[77]

The EIS study projects total direct employment related to the Southern California OCS lease sale to peak at about 15,000 by 1987 (assumes production of about 1 million b/d of oil); induced employment has been estimated at 8,000 to 10,000. The latter represent people who are already living in Southern California.[78] A study by a private consulting firm has estimated that direct employment related to the lease sale will peak at 16,300, and induced employment at 19,600 during the 11th to 15th year of development (assumes completion of the maximum projected number of platforms, 60).[79]

The study undertaken for the Western Oil and Gas Association estimates that direct employment asociated with the development of Southern California's OCS lands will be around 5,000, compared with current California oil field employment of around 21,000. Assuming a production of 4 billion barrels of oil from Southern Californian OCS lands, an additional 5,000 to 6,000 man-years of construction labor would be needed during the peak years up to 1990.[80] The study does not provide a figure for induced employment. The WOGA study concludes that the numbers employed would be relatively small, and that it would create little employment impact in this heavily populated area. The authors of the WOGA study maintain, however, that the employment created is significant in that it would tend to offset the decline in existing oilfield employment in the state of California.[81]

In view of the fact the bulk of the jobs created during the labor-intensive development stage is expected to be filled by people who are already living in Southern California, the EIS statement of the Bureau of Land Management concludes that even at peak employment levels the number of people looking for houses will be accommodated

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[76] "Environmental Assessment Study. Proposed Sale of Federal Oil and Gas Leases Southern California Outer Continental Shelf." op. cit. pp. 19 and 20.

[77] "Proposed 1975 Outer Continental Shelf Oil and Gas Lease Offshore Southern California." op. cit. p. 264.

[78] Ibid., p. 264.

[79] Dames and Moore. "Critique of Bureau of Land Management Draft Environmental Statement For Lease Sale 35." Los Angeles. May 19, 1975. p. 98.

[80] Western Oil and Gas Association. Environmental Assessment Study Proposed Sale of Federal Oil and Gas Leases Sothern California Outer Continental Shelf. Section IV. "Assessment of Potential Environmental Impacts." October 1974. p. 5–15.

[81] Ibid., p. 5–15.

without difficulty. For the same reason services impacts are expected to be minimum.[82] The principal area of impact will be Los Angeles County, followed by Orange County and Ventura County.

Aesthetic Impacts

There are two kinds of adverse aesthetic impacts: one results from blowouts, the other is related to the visual impact of drilling rigs and production platforms in the ocean. Whenever a blowout occurs (such as in Santa Barbara in 1969), one may expect an adverse visual impact, the extent of which is dependent on the size of the spill and on the volume of crude oil reaching the beach. The other kind of adverse impact is related to the construction of platforms offshore, and treatment and other facilities onshore. In contrast to the potential Atlantic developments of the OCS, many potentially oil-bearing structures off the California coast are only a few miles off the coast. Drilling rigs and production platforms are likely to be visible in many areas during at least part of the year, and treatment facilities are likely to be constructed close to the shoreline.

According to the authors of the EIS of the Bureau of Land Management, platforms will cause the longest lasting, most prominent visual aesthetic impact wherever they are installed. Visual impacts can be viewed in two ways: 1) impacts increase in magnitude when they occur in a totally natural environment or 2) impacts increase in magnitude when they are visible to a greater number of people. Under these circumstances, platforms on the Outer Banks in Southern California would produce a greater impact in criterion 1, while they would produce a greater impact in Santa Monica and San Pedro Bays under criterion 2.[83]

The EIS report continues that if platforms are permitted in Santa Monica Bay, they will be visible much of the time from nearly all of the coastal viewpoints, and will affect the view considerably. In San Pedro Bay platforms will be viewed against an already industrialized cluttered skyline in the Los Angeles-Long Beach Harbor area. In Orange County, offshore wells exist in state waters as far south as Huntington Beach, thus platforms in Federal waters would constitute much less of a contrast with existing conditions than they would in Santa Monica Bay. South of Huntington Beach, the shoreline is less developed and not industrialized. From Huntington Beach south to the end of the lease sale area near San Mateo Point, the visual impact is increased, approaching those conditions prevailing in Santa Monica Bay, Santa Barbara-Catalina tracts may occasionally be visible from the mainland, but platforms would appear very small and indistinct. The Santa Rosa-Cortes North tract area is exposed to a few permanent residents, and visual impact will be seen by boaters primarily.[84]

In a critique of the Bureau of Land Management's EIS, the Dames and Moore study states that the cumulative effects of the earth's curvature, relative platform prominence, and atmospheric phenomena on the visibility of a proposed offshore platform all act to diminish the possible visual impact of the structure. Of the estimated 60 to 62 plat-

[82] "Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale, Offshore Southern California," op. cit. pp. 268 and 269.
[83] Ibid., p. 238.
[84] Ibid., pp. 240–241.

forms (the maximum estimate), only 18 would be visible from promontories and other elevated scenic viewpoints along the shoreline, according to this study. For those platforms visible from shore Dames and Moore maintain that the visual impact will indeed be significant to some people, but this interruption of the existing seascape would not be critical to most people.[85]

Economic Impact

Depending on the volume of recoverable resources, the EIS estimates that total revenue from the Southern Californian lease sale could vary from $11.2 to $146.8 billion over the productive life of the lease sale area. These figures are based on the original 297 tracts offered and not on the 70 that were actually sold on December 11. The Bureau of Land Management assumed an oil price of $10.00 per barrel and a price of natural gas of $0.60 per thousand cubic feet of natural gas. Total revenue generated for state and local taxes is projected at 35% of total revenue, and total capital expenditures flowing into the economy would be over $17 billion expended over the next 30 years. Income from primary employment is estimated at $25 billion for the productive life of the lease sale area, which, at a conservative multiplier of 2.5 would yield $87 billion of economic activity, according to the study.[86]

The 1964 study by WOGA estimated that if 4 billion barrels of oil and 8 TCF of natural gas were developed from the Southern California OCS lease sale, about $45 billion revenue would be developed from oil and gas, and 40% of this would appear as revenue to federal, state and local governments.[87]

Income from salaries related to direct and indirect employment would be substantial. The Dames and Moore study has calculated about $149 million annually for the first 5 years, and $504 million for the 11th to 15th years.[88]

Trade Offs: California's oil production and consumption were equally balanced at approximately 850,000 b/d in the late 1950's. Production peaked at 1,022,000 b/d in 1968 and has steadily declined since that point. Current shortfall between production and consumption is 800,000 b/d, a figure that could grow to 2.5 million b/d in 1985. If California were to receive not only a share of the estimated Alaskan production of 2.0 million b/d by 1985, but would in fact receive it all, there would still be a shortage of between 300,000 and 500,000 b/d. The EIS states that assuming optimistic resource estimates for the Southern California OCS, the shortfall between petroleum supply and demand in California in 1985 could be 1.1 rather than 1.75 million b/d. In other words, while the OCS development would not eliminate California's dependence on imported oil, it would reduce the degree of dependence. Substantial imports of oil would still be required in California even though all offshore production would be used for the state's own consumption. The natural gas situation is said to be simi-

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[85] "Critique of Bureau of Land Management Draft Environmental Statement For Lease Sale 35," op. cit. p. XIV.

[86] "Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale, Offshore Southern California," op. cit. p. 294.

[87] Environmental Assessment Study Proposed Sale of Federal Oil and Gas Leases Southern California Outer Continental Shelf. Section IV. "Assessment of Potential Environmental Impacts." op. cit. p. 5–4.

[88] "Critique of Bureau of Land Management Draft Environmental Statement For Lease Sale 35," op. cit.

lar to the oil situation.[89] A temporary postponement of the lease sale requested by the State of California would only have delayed the production date from the lease sale area by the amount of time resulting from the lease sale postponement.

Cancellation of the Southern Californian lease sale could have cost the nation between $0.5 and $4 billion annually, according to the EIS, and the region could have lost some 25,000 jobs at peak production. Moreover, the nation might have lost additional induced employment related to the production of specialized tools and machinery, platforms, drilling rigs, boats, marine equipment, and so on.[90]

Santa Barbara Leases

On August 16, 1974, the Department of the Interior approved a plan for development of oil and gas discovered on 83,000 acres of OCS lands in an area about 20 miles northwest of Santa Barbara. The lease concerned 17 tracts, known as the Santa Inez Unit. It has been estimated to contain between 700 million and 1.1 billion barrels of oil and between 370 and 550 billion cubic feet of natural gas.[91]

The approved development plan calls for the construction of a self-contained drilling and production platform in 850 feet of water. The oil will be piped ashore in 12 and 16 inch pipelines to onshore treating and storage facilities. If offshore instead of onshore treating facilities are used, the natural gas produced with the oil will have to be reinjected into the reservoir. Full scale development of all Santa Barbara oil fields on Federal and State lands have been estimated to yield a maximum of 200,000 b/d.[92]

Exxon purchased 1,500 acres of land for the treatment and storage facilities some 20 miles north of Santa Barbara, on the north side of Highway 101 in Coral Canyon. The project itself will only require 15 acres, and another 8 acres surrounding the site will be involved in landscaping. An additional 58 acres will not be used for any purpose other than possibly brush control or grazing. The rest of the 1,500 acres will be used for existing agricultural and oil field purposes.[93] Another 16 acres will be needed for the access road to the canyon.

Impacts

At the beach, where the pipeline will come ashore, there will be some temporary disruption until the area has been restored after placement of the necessary pipe. Soon, there will be no visible sign left of the underground pipeline. New power lines, utility lines and telephone communication lines going up the canyon would be installed underground. The site will contain four large tanks for oil storage, oil treatment facilities, and gas processing facilities. The facility is a major improvement over earlier onshore developments in Santa Barbara. The Exxon facility at Corral Canyon has been designed to do for the 83,000 acre Federal OCS area (Santa Inez unit), that which was done for the 84,000 acre state area with 13 separate

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[89] "Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California," op. cit. pp. 307–309.
[90] Ibid., pp. 293–294.
[91] "Oil and Gas Development in the Santa Barbara Channel Outer Continental Shelf Off California," op. cit. p. I–173.
[92] Ibid., p. III–177.
[93] Excerpts from Exxon Statement to Santa Barbara County Board of Supervisors. January 13, 1975, p. 2.

facilities.[94] Exxon has propsed that oil treated by the Corral Canyon facilities be shipped by tanker to refineries elsewhere in the State of California. The staff of the California Coastal Commission has recommended that Exxon consider constructing an overland pipeline instead. This proposal has been refused by the company.[95]

Exxon could build the treatment and storage facilities offshore on a floating vessel. A plan of operations including such an option was approved by the Department of the Interior in August of 1974. In that case no onshore facilities would be needed, but aesthetics and the increased possibility of oil spills are among the major factors raised in objection to this alternative. Moreover, natural gas would not be treated but instead be re-injected into the ground (too complex to construct offshore gas treatment facilities) and thus be lost for consumption. Finally, Santa Barbara County could loose as much as ¾ of a million dollars per year in tax revenues as a result of refusing the construction of the facilities at Corral Canyon.

The economic impacts from developing the Santa Inez unit are expected to be of measurable, but not of major magnitude. Movement of employees into and out of the area is expected to be absorbed within normal community development, with Ventura county receiving the largest share. Personnel moving into the area would tend to gravitate to areas where housing, schools, and other amenities are available. As a result, this would probably create a small increase in dollar flow to merchants. The exodus and replacement of labor as production eventually declines is expected to be gradual.[96] It has been estimated that the number of employees would be approximately 1,200 during the exploration phase, 2,200 during the development phase, and about 1,600 during the production phase.[97] Only a small percentage of the labor utilized during the exploration phase would be hired locally; the remainder would be mostly contract labor from within the Southern Californian region. Total increase of employment related to the Santa Inez development would be no more than about 7% of the expected growth in employment in the region. The U.S.G.S. maintains that the labor introduced in the area for Channel development over an 8-year period is anticipated to increase to a level of about 3,500 out of a total increase in civilian employment in the region of 50,000. The 3,500 represent such a small portion of the total, that any aggregate socio-economic impacts within the Santa Barbara Channel are are expected to be minimum.[98] Rather than a 'bust and boom' period following the development of the Santa Inez unit, the U.S.G.S. expects a gradual increase of employment (and thus of population) over the first 8 years of development, staying rather stable until the 25th to 30th years when production and employment would again decline gradually until the end of the area's productive life.[99]

Tourism may be marginally affected by the new oil developments. Some possible interference with pleasure craft activities in the harbor may occur, and construction in the vicinity of the beach area could

[94] bid., p. 6.
[95] Santa Barabara News-Press, November 27, 1975.
[96] "Oil and Gas Development in the Santa Barbara Channel Outer Continental Shelf Off California," op. cit. vol. 2 III-186.
[97] Ibid., p. III-179.
[98] Ibid., p. III-131
[99] Ibid., p. III-131.

result in a short-term drop in beach attendance. During the production phase there will be some positive impact on sportfishing, and some negative aesthetic effects. The possibility of oil spills, but chances have been significantly reduced since the 1969 blowout due to stricter regulations and improved technology. The costs of the 1969 blowout has been estimated at about 16.4 million dollars by Professors Mead and Sorensen of the University of California at Santa Barbara, but if a blowout were to occur in the Santa Inez lease sale area, it would not have the same economic impact as the 1969 blowout because of different location, geological conditions, more stringent regulations, and other parameters; and perhaps more importantly, the industry is better organized and has more advanced oil-spill containment equipment and procedures readily available for use.[100]

Northern California

While no lease sales are planned for OCS lands off Northern California, the San Francisco area as well as parts of Oregon and Washington are likely to be impacted by offshore petroleum developments in the Gulf of Alaska. San Francisco is one of the areas where some of the Alaskan oil may be brought ashore, treated, and refined. The 1974 environmental assessment of offshore oil development in the Atlantic and Pacific OCS undertaken by the Council for Environmental Quality estimated that employment in the San Francisco area related to Alaskan OCS development would grow by 16.4 to 28.3 thousand, and total population from 33.7 to 67.3 thousand. Also, between 5,200 and 7,300 acres of land would be needed to accomodate refineries.[101]

Even though the CEQ figures may be on the high side, the study concludes that such population would not have a major effect on provisions of services in the area, with the possible exception of the water supply.[102] Availability of land might be a problem, because there just does not seem enough land in that area to accommodate OCS-induced growth.[103]

The Puget Sound area in the State of Washington would also be one of the places where Alaskan oil may be treated and refined. The CEQ report estimated employment in the Washington/Oregon area related to OCS development in the Gulf of Alaska to grow by 17,000, and the population by 33,000. Acreage required for onshore facilities in Oregon and Washington was projected at 10,800.[104] No other impact statements have been for these areas to compare employment and land use figures.

Coastal Zone Management

California completed a comprehensive Coastal Zone Management Plan in December 1975. After the Plan has been adopted by the Californian Legislature, it will be forwarded to the Secretary of the Interior. If approved, the impact can be significant for future oil and gas developments affecting the coastal zone of the State of Caifornia.

[100] Ibid., p. III-182.
[101] Council on Environmental Quality. op. cit., p. 7-62.
[102] Ibid., p. 7-62.
[103] Ibid., p. 7-62.
[104] Ibid., p. 7-70.

The California Coastal Z ·ne Management Plan calls for the following policy: [105]

1. New offshore oil and gas developments of State and Federal lands shall be permitted only when identified as part of an overall balanced energy program in the United States, when California's needs are clear, and after the coastal agency has determined that onshore impacts are acceptable.

2. Applicants for drilling permits in State owned offshore lands will be required to submit one-, five-, and ten-year plans for exploration, development, production on all related onshore and offshore developments, to State agencies.

3. Offshore drilling will be allowed only in areas where the geologic characteristics have been adequately investigated, and with the most advanced drilling technology. Well sites ~~need be chosen~~ where they will be least environmentally hazardous and aesthetically disruptive.

4. Whenever possible, consolidation and unitization of all operations related to offshore oil and gas developments.

5. Submerged completion and production systems should be used where feasible and environmentally safe. Wherever this cannot be done, platforms are preferred over islands.

6. Impact of onshore facilities should be minimized. Wherever developments would result in substantial adverse impacts to the resources of the coastal zone, it shall be permitted only upon a demonstration that there is a need for the project (need is further specified, see appendix, p. 295).

7. All exploration calls for the California Legislature to enact that exploration- and development-related data need to be submitted within 60 days to the Division of Oil and Gas.

8. Encourage oil recovery efficiency, and calls for the California Legislature to regulate petroleum completion and production for individual wells, including setting maximum efficient rates of production, as analogous government agencies do in other major oil producing states.

9. Appropriate Californian agencies should seek from Federal agencies agreement that Federal OCS leases will be approved by the Department of Interior only if the following conditions are met: a) Demonstration of need, b) Public review of proposed OCS plans, c) Disclosure of short- and long-term plans, d) Prevent drainage of State Petroleum sanctuaries, e) Establish stringent safety standards, f) Evaluate unitization or consolidation possibilities, g) Consider uses of subsea systems, h) Share some revenue with the states, i) Designate sanctuaries in certain areas, j) Make Federal OCS developments compatible with the State of California's Coastal Plan.

10. Prevent land subsidence by reinjecting brines into oil fields.

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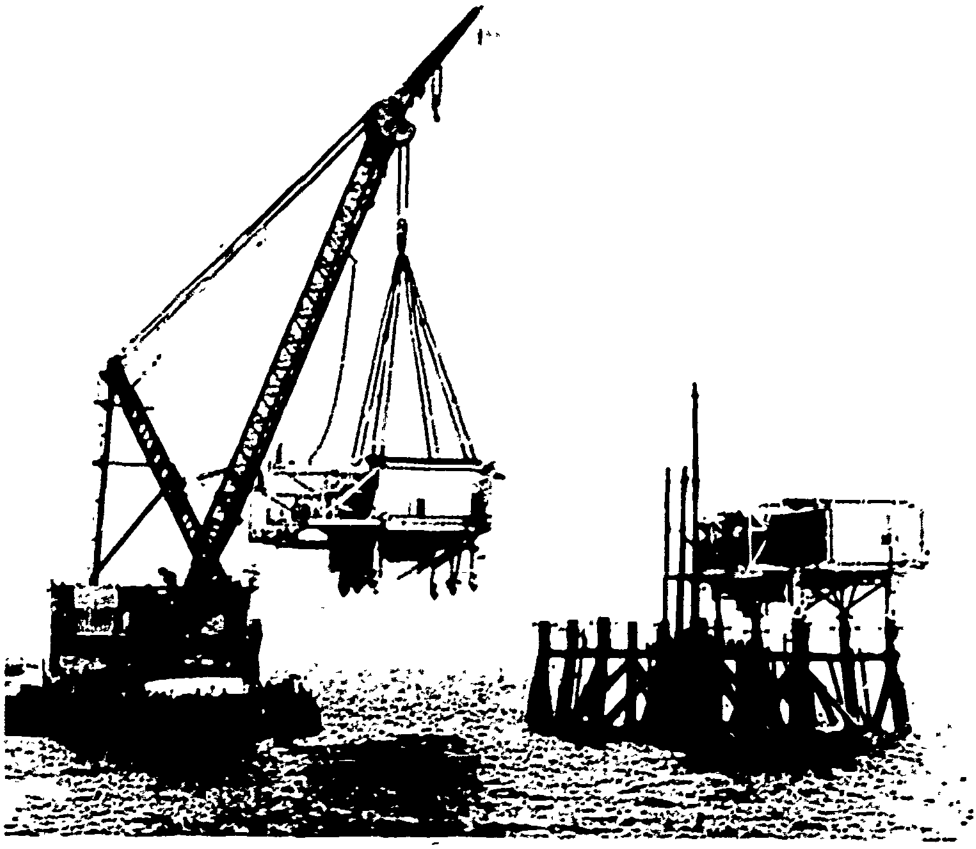
[105] California Coastal Zone Conservation Commission, Preliminary Coastal Plan, San Francisco, March 6, 1975, pp. 215–223. See appendix for detailed description.



Crane barge lifting a 1750 ton deck module onto the jacket section of a production platform in BP's Forties oilfield in the North Sea.

Courtesy British Petroleum Company.

Atlantic OCS Development

The first major study on the potential environmental and socio-economic impact of offshore oil and gas developments in the North, Middle and South Atlantic, was undertaken by the Council on Environmental Quality. It was completed and published in April 1974.

The CEQ study was based on a set of complex geographical and industrial development assumptions for three regions with petroleum potential: New England, the Mid Atlantic, and the South Atlantic. In addition, the report covered coastal zone impacts related to off-shore oil and gas developments in the Gulf of Alaska.

The CEQ report oil and gas production assumptions for the three Atlantic areas were: a low volume projection of 250,000 b/d of oil and 0.30 billion cubic feet/day of natural gas by 1985, and a high volume estimate of 750,000 b/d of oil and 0.90 billion cubic feet/day of natural gas. Low volume estimates for the year 2000 were 500,000 d/b of oil and 1.8 billion cubic feet/day of natural gas, and high volume estimates for that year were 1.5 million b/d of oil and 3.6 billion cubic feet/day of natural gas.[106] For the purpose of the study it was assumed that production in each of the three regions would be the same. Regions

[106] Council on Environmental Quality. "Oil and Gas—An Environmental Assessment" Volume 4. Washington, D.C. April 1974. pp. 3-17 to 3-21.

and localities most likely to be affected are indicated on figure 22. In its computations of required acreage and employment creation affect of OCS developments, the CEQ report included development of refineries and petro-chemical industries. Many other impact statements leave development of refineries and petro-chemical industries out, because construction of those industries are not directly related to offshore oil and gas developments. Development of refineries and petro-chemical industries is related to demand for products in a certain area, and not necessarily to availability of supply of raw materials.

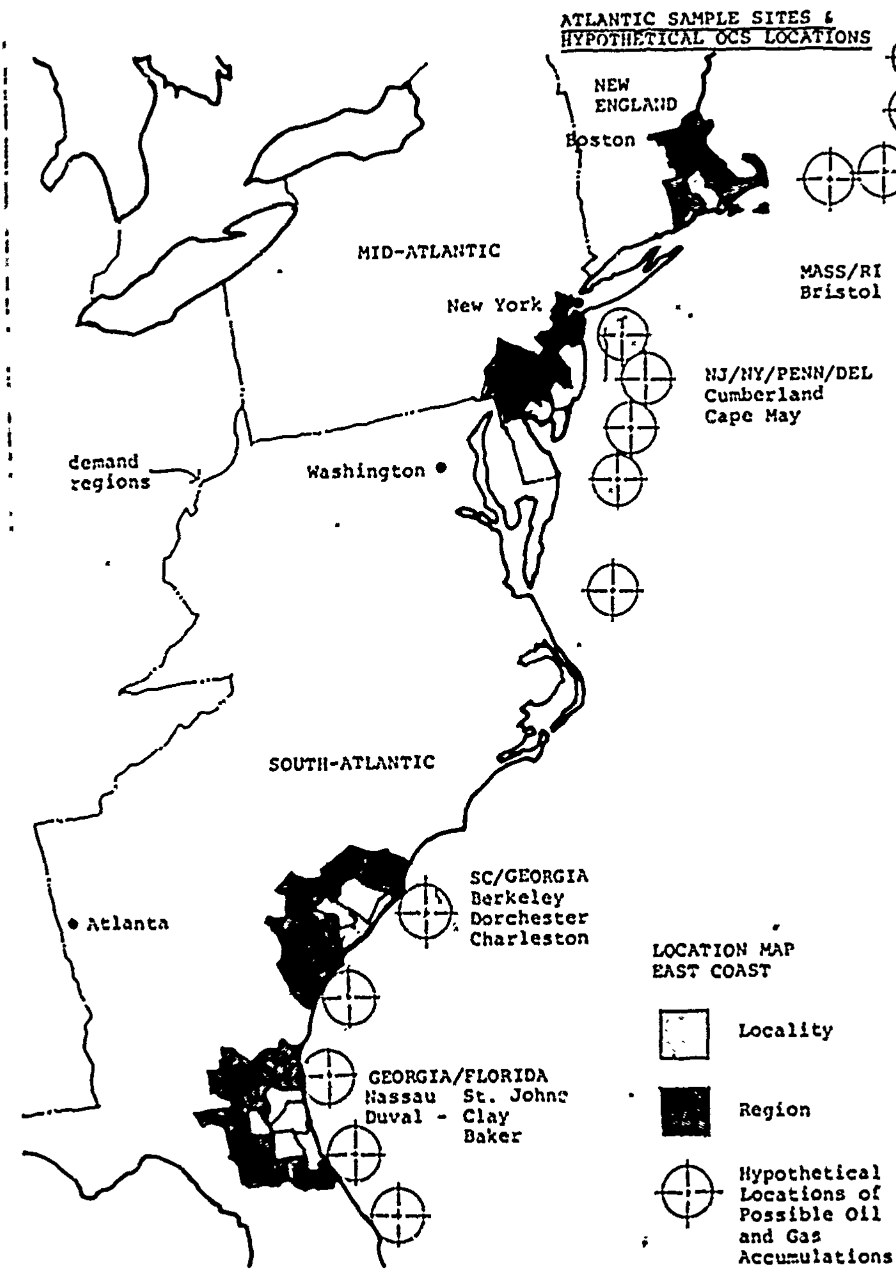


FIGURE 22

Source: *CEQ. OCS and Gas-An Environmental Assessment*. p. 2-5.

New England

The oil and gas industry nominated 1,927 tracts covering 10.9 million acres for New England OCS development. The Bureau of Land Management has made a tentative tract selection for the Georges Bank OCS lease sale proposed for August 1976. The area to be leased has been reduced to 206 tracts covering 1,172,796 acres. Many of the tracts received only one nomiation ,and other areas were omitted on the recommendation of various state agencies and the fishing industry. No tracts within 50 miles of the shore will be leased. The proposed lease area is 50–200 miles from Nantucket Island in water depth of 45 to 600 feet. Prior to the August lease sale, the Bureau of Land Management will have to file an Environmental Impact Statement.

The CEQ study projected that the most significant onshore impact would be felt in Bristol County, Massachusetts.

Employment: Including jobs in refining of oil and processing of oil and gas into petrochemical products, the CEQ report projected that by 1985 New England would gain 20,300 jobs under low development assumptions, and 76,700 jobs in case of high development. By the year 2000, some 21,000 jobs would have been created in New England under low development assumptions, and 83,100 in case of high development.[107] Although construction-related employment in the year 2000 is only about one-third of the 1985 figure, the CEQ report projects significant increases in total OCS petroleum-related employment, because of developments in the petro-chemical industry, refining and "other industries".[108] Most recent studies have come to the conclusion that employment related to offshore oil and gas developments follows a bell-shaped curve, rising rapidly for some years, and declining rapidly once the construction phase has been completed.

The largest number of jobs (about one-third) would be created in Bristol County, Massachusetts, where unemployment is currently substantially above the national average. The CEQ study concluded that the socio-economic impact was not expected to cause any significant problems for New England, but could cause strain on local community problems.

> * * * The impact from offshore production is not expected to present significant problems to the systems and institutions that serve Bristol County locality. The high impact and physical and social systems averages an additional demand of nearly 9% in 1985 and 7% for the year 2000 over base case 1. When examined in aggregate, this growth seems modest and manageable in terms of existing public water supply, school, hospital, and housing construction, but local impact could cause considerable strain on community services (schools, hospitals, etc.)[109]

Total population growth related to high dev. of OCS was estimated at about 44,000 for Bristol County and approximately 189,000 for all of New England. (7–20) As indicated above. Bristol County could cope with the population increase, but the CEQ report maintains that careful planning is needed to avoid that most of the population growth would take place in smaller communities.

> * * * If two or three of the County's dozen communities of about 10,000 people were to receive a majority of the projected 44,000 new inhabitants, existing facili-

[107] Ibid., pp. 3-17 and 3-19.
[108] Ibid., pp. 3-17 and 3-19.
[109] Ibid., p. 3-22.

ties would be significantly strained, particularly in Massachusetts, where over the years great efforts have been made to retain the traditional architecture and central commons in each small towns * * *.[110]

A recent study on Georges Bank oil and gas development undertaken by the Arthur D. Little Corporation for the New England Regional Commission, is more modest with its projections of direct and indirect employment impact. The study assumes oil production of 100,000 b/d for the first five years, 410,000 b/d after 10 years of effort, and 1,020,000 b/d at peak production in the 20th year. Natural gas production for the same periods were respectively projected at 130,000 b/d, 290,000 b/d, and 580,000 b/d (oil equivalent).[111]

Employment was estimated to grow by 5,400 (3,300 direct) with a payroll of $79 million after five years. After 10 years, employment would have grown to 8,800 (4,800 direct) with a payroll of $120 million. Employment would peak at 17,800 (7,500 direct) after 20 years, and the payroll would be about $220 million.[112]

During the first five years only about 10% of offshore exploration and development jobs would be available to New England residents, according to industry sources. The number might increase to 30% in 20 years of OCS exploration and development activity, especially if State training assistance is forthcoming. After five years, 85% of the new employees are expected to resettle in New England, and during the next 10 years about 70% are expected to relocate in the region. About 40% of the out-of-state employees are estimated to be married. On the basis of this information, the study concludes that during the first five years of operations about 6,600 new people will relocate, a figure likely to rise to 9,200 after 10 years, and to 12,300 after 20 years.[113] Hence, total population growth associated with gradual development of offshore oil and gas resources in New England is substantially below the figures quoted in the CEQ report, even after taking into account a peak oil production figure of 1.5 million b/d in the CEQ report versus about 1 million b/d in the Arthur D. Little Report.

A study by the Gulf South Research Institute estimated that regional employment associated with offshore oil and gas development off the Atlantic coast could rise between 15,400 and 20,900 for the entire Atlantic region (depending on low or high finding rates). A study by Dr. William Ahern of Harvard University on oil and gas developments in the Georges Bank area, estimates that some 600 new jobs would be created at a production rate of 500,000 b/d (direct jobs only).[114]

The Arthur D. Little study like the CEQ report includes construction of refineries in its employment figures. The study justifies the inclusion of refineries by arguing that extensive petroleum-related industrial development will only take place in New England if substantial discoveries of oil and gas are made.[115]

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[110] Ibid., p. 7–19.
[111] New England Regional Commission. "Effects on New England of Petroleum-Related Industrial Development." Boston. 1975. p. 1–75.
[112] Ibid., p. 1–74.
[113] Ibid., p. 1–75.
[114] See U.S. Senate. Committee on Commerce. National Ocean Policy Study. "Outer Continental Shelf Oil and Gas Development and the Coastal Zone." 93rd Congress. 2nd Session. Washington, D.C. 1974. p. 11.
[115] "Effects on New England of Petroleum-Related Industrial Development," op. cit. p. III-I.

Land Use

The CEQ report estimates that under its high development assumption oil-related industries would require 7,000 acres of land in Bristol County, and about 24,000 acres in all of New England. The report concludes that adequate land is available for the required onshore developments in New England, including space for refineries and the petrochemical industry. The report calls for constraints on the use of wetlands and the coastal zone in general, but also indicates that . . . "adequate land suitable for OCS-related development and normal growth should be avalilable if comprehensive planning is undertaken at an early date." [116]

Lease sales off New England have not been scheduled until the late summer of 1976, but a draft environmental impact statement should be completed early in the year.

Trade Offs: Assuming high development, the CEQ report puts the value of offshore New England oil and gas production at about $3.2 billion in 1985 and approximately $5.4 billion by the year 2000.[117] The Arthur D. Little study estimates the value of extracted oil at $542 million after 5 years of production, at about $1.9 billion after ten years, and at approximately $4.5 billion after 20 years of activity.[118] Under these assumptions, the nation would lose several billion dollars over a period of ten years if development were not to take place, and dependence on foreign imported oil could rise by 100,000 b/d to a few hundred thousand b/d. Regionally, states and localities would have to forego significant tax revenues from oil and oil-related developments, and the unemployment rate for the region would be slightly higher. Development of Georges Bank resources, on the other hand, would improve oil and gas availability in the New England states, because the oil and gas produced would probably stay within the region.

Mid Atlantic

States likely to be impacted by OCS developments in the Mid-Atlantic region include: New Jersey, New York, Delaware and Maryland. The Department of the Interior has decided to lease tracts for oil and gas development in the area of the Baltimore canyon, which, according to available data, is thought to have the best potential of the major east-coast offshore basins. Estimates on the petroleum potential of the Mid-Atlantic OCS vary considerably, but whether and how large a volume of commercially exploitable oil and natural gas will be found, cannot be estimated until the area is put to the test of the drill. The US Geological Survey estimated in September 1975, based on proprietary geophysical data, that the undiscovered recoverable re-

[116a] "Oil and Gas—An Environment Assessment," Volume 4. op. cit. p. 8-30. Depending on the degree of OCS development (which in turn depends on resources, estimates and total development assumptions), the Arthur D. Little Study, undertaken for the New England Regional Commission, estimates onshore acreage needed for New England OCS oil and gas development at between 1,017 and 3,795 acres. The latter figure includes refining capacity and petro-chemical developments even if one compares the highest figure of land use in this study with the CEQ report, the latter's land use projection are about six times higher than the estimates in the study conducted by Arthur D. Little.

[116b] New England Regional Commission, Effects on New England of Petroleum Related Industrial Development. op. cit. p. II-10.

[117] Ibid., p. 3-21.

[118] "Effects on New England of Petroleum-Related Industrial Development." op. cit. p. 1-8.

sources of the Baltimore Canyon range from 0.4 to 1.4 billion barrels of oil and 2.6 to 9.4 of natural gas.[119]

Employment:

The 1974 CEQ report estimated total employment related to OCS activities in the Mid-Atlantic OCS at just over 100,000 under its high development assumption. The low development scenario projects employment to grow to slightly less than 35,000 after 10 years of OCS activities. Locally, in Cape May and Cumberland counties (NJ), employment would rise by 28,800 or 8,500 depending on the high or low development scenario. Under the high development scenario the regional population would rise by 227,000; the population in the substantially impacted New Jersey Counties by 59,600.[120]

The CEQ report maintains that on the basis of their findings, locally, high OCS development could result in severe strains on social services, and in particular education. CEQ suggested that much of the development would take place in basically rural counties with little urban development. Because of the lack of large cities, the major impact would be felt by small towns and fishing villages, which—according to the report—could be overrun with new development.[121]

The BIS of the Bureau of Land Management, based on substantially lower production of oil and gas than the CEQ report, projects on the basis of the quoted resources estimates, that increase in employment associated with the OCS developments in the region could range between 4200 and 15400 persons, of which about 900 to 3600 would be directly employed by OCS-related activities.[122]

Not all of the increased jobs in the region would be filled by persons coming from outside the region. Hence, maximum population increases in the Mid-Atlantic region are estimated at no more than between 5600 and 20,800.[123] This represents a population increase of less than one percent from base case levels. The population figures quoted here are for 1986, the anticipated peak employment year.[124] The OCS-induced population gains within the region probably would not alter the normal growth rate (projected at about 1.5% per year) by more than five hundredth of one percent between now and 1990.[125] However, OCS induced population growth will not be uniformly insignificant throughout the region. For example, if onshore developments would primarily be located in rural, under-populated areas, impacts would be felt much more than if more heavily populated and industrialized areas. Some counties, such as Nassau County have experienced economic decline, a decrease in population and a net out-migration of people. Such developments may have caused the underutilization of a county's physical and service capabilities if these systems were overbuilt.[126] Other counties in the Mid-Atlantic region, especially the counties along Maryland's eastern shore have an underdeveloped infrastructure and service system. Hence, actual impacts upon the infrastructure will

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[119] Department of the Interior, Bureau of Land Management. "Draft Environmental Statement, Proposed 1976 Outer Continental Shelf Oil and Gas Lease Sale Offshore the Mid Atlantic States." Washington, D.C. 1975. p. 1.

[120] "OCS Dil and Gas. An Environmental Assessment," vol. 4. op. cit. p. 18 and p. 7–68.

[121] "OCS Oil and Gas—An Environmental Assessment," op. cit., p. 7–31.

[122] Draft Environmental Statement. "Proposed 1976 Outer Continental Shelf Oil and Gas Lease Sale Offshore the Mid Atlantic States," op. cit., p. 179.

[123] Ibid., p. 180.

[124] Ibid., p. 205.

[125] Ibid., p. 206.

[126] Ibid., p. 212.

greatly depend upon the distribution of the induced population, whether or not in is widely dispersed and/or the ability of an area, based upon its infrastructure capabilities, to absorb the population increase.[127]

The EIS concludes that on the county level, based upon the economic analysis made in the EIS, it is anticipated that the greatest population difference between the high discovery case and the without development case would be approximately 10,000 persons. In Manhattan a population increase of that magnitude would account for less than five percent of the projected population change between 1975 and 1980 without OCS development. Unless all 10,000 persons more into the same neighborhood at the same time, the change would be imperceptible. If, on the other hand, 10,000 additional persons were added to the population of Northampton County, Virginia, the increase would be equal to about 67% of the county's current population. Infrastructural problems would be monumental, and costs to local government so high, that front-end moneys would be necessary in order to plan and implement the facilities needed to accomodate such increases.[128]

A report entitled A Study of the Socio-Economic Factors Relating to the Outer Continental Shelf, published by the University of Delaware in 1975, estimates that a minimum of 30,000 new jobs could be created in the Mid-Atlantic region, if OCS activities were to assume substantial levels.[129] Substantial levels is described as a production of about one-half that of Texas and Louisiana offshore. Offshore production of those two states is slightly over one million b/d of oil and about 10 billion cubic feet of natural gas.[130] Like the EIS of the Bureau of Land Management, the study by the College of Marine studies concludes that the large size of the industrial base in the Mid-Atlantic region may make the impacts small relative to the size of the region.[131] Local impacts, however, can be substantial, according to the study.

Joel M. Goodman of the University of Delaware made a study on OCS developments in the Mid-Atlantic region, and concludes that on the basis of 21 drilling rigs operating off the Mid-Atlantic coast by 1980, 3780 jobs may be created to operate and service the facilities. Another 11,340 indirect jobs—needed to service these directly employed—would bring total job creation related to Mid-Atlantic OCS development at 15,120.[132] Dr. Goodman suggests that many of the 15,000 employees, and in particular those working offshore where crews usually have a 7-days on and 7-days off work schedule, do not necessarily have to live in the coastal zone, but could be living in cities like Washington, Baltimore and Philadelphia, which are not too remote from the operations base. Many of the employees who would be working directly or indirectly for support industries are already living in the region.[133]

Finally, a study by Woodward-Clyde Consultants estimates that total direct employment opportunities related to Mid-Atlantic OCS

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[127] Ibid., p. 211.
[128] Ibid., p. 216.
[129] College of Marine Studies. University of Delaware. "A Study of the Socio-Economic Factors Relating to the Outer Continental Shelf of the Mid Atlantic Coast." Newark. 1975. p. 17.
[130] U.S. Department of the Interior. Geological Survey. "Outer Continental Shelf.Statistics." Washington. D.C. June 1974. pp. 81 and 82.
[131] "A Study of the Socio-Economic Factors Relating to Outer Continental Shelf of the Mid Atlantic Coast." p. 17.
[132] Joel. Goodman. "Decisions for Delaware: Sea Grant Looks at OCS Development." University of Delaware. February 1975. p. 27.
[133] Ibid., p. 27.

development may rise from 633 during the first year of exploration, to a maximum of 12,933 in the 16th year of development. This does not include the work force that may be required for pipeline construction, since the currently indeterminate length of the necessary pipelines precludes estimation of employment requirements.[134] Indirect and induced opportunities created in response to the OCS development plan would increase the total number of OCS related employment opportunities throughout the Mid Atlantic region to nearly 28,000.[135]

The Woodward-Clyde study's estimate of job creation related to development of the Mid-Atlantic OCS petroleum resources is very close to the projections of the College of Marine Studies. Woodward-Clyde assumes a resource base of 6 billion barrels of oil and 32 TCF of natural gas; a peak production of 1.1 million b/d of oil and 8 billion cubic feet of gas; a need for 15 exploratory and 80 development rigs, and 180 production platforms.

The study concludes that total projected OCS-related employment opportunities are modest, numbering less than 0.2% of the persons employed there in 1970. Workers relocating to the region to fill some of these positions should number no more than 2% of total regional population growth. Their demands for housing, land, and recreation are small in comparison to the demand created by population growth not related to the development program.[136]

Woodward-Clyde maintain that as there is no certainty where the onshore development will take place after oil and gas has been located, the authors of the study utilized a computer-assisted mapping system to identify areas within the Mid Atlantic region demonstrating high probability to accommodate OCS development. Two sample areas were chosen: one in Southern New Jersey (Atlantic, Camden and Gloucester Counties); the other area is located in Virginia and consists of Chesapeake, Hampton, Newport News, Norfolk, Portsmouth, Suffolk and Virginia Beach cities, York, and the Isle of Wight Counties. In the first area, the study estimates that about 10,000 new jobs may be created. About 4,500 are expected to relocate to the area. This represents about 2% of projected growth in area population between 1970 and 1990. OCS related demands for housing, land, and recreation are considered small in relation to the normal population growth which may be anticipated.[137] The relocated population may require about $4 million in local government expenditures during the peak production year.

In the second study area, some 13,000 jobs are expected to result from OCS related activities. Relocation to the area may reach 5,400 persons, representing about 2% of the anticipated population growth in the area from 1970–1990. Again, demand of these people for housing, land, and recreation are small in relation to demand created by anticipated growth.[138] About $3.3 million may be needed to cover local government expenditures for public services improvements and additions.

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[134] Woodward-Clyde Consultants. "Mid Atlantic Regional Study. An Assessment of the Onshore Effects of Offshore Oil and Gas Development." October 1975. p. 18.
[135] Ibid., p. 18.
[136] Woodward-Clyde Consultants. "Mid-Atlantic Regional Study. An Assessment of the Onshore Effects of Offshore Oil and Gas Development. Executive Summary." October 1975. p. 1.
[137] Ibid., p. 19.
[138] Ibid., p. 20.

Economic Activity

The Woodward/Clyde study concludes that employees at OCS related developments are projected to earn as much as $177 million in wages during the peak year of OCS production. During the first 16 years of development, nearly $1.6 billion in wages may be earned by workers based on 1975 east coast wage levels.[139]

Land Use

In some counties along the Atlantic seaboard there is not much land available for primary development, because of extensive beaches, salt marshes, and recreational lands, but northern Cumberland, Salem, and Gloucester counties, which are already partially industrialized and part of the Delaware Valley complex, may have land available for additional growth at existing and new sites. Refineries and other primary industry may also locate at existing industrial centers around Philadelphia and in Northern New Jersey, according to the 1974 CEO report.[140]

According to the CEQ report, OCS developments in the Mid Atlantic region would require between 16,100 and 49,300 acres of land, depending on low- or high-development.[141] The study includes land required for refinery and petro-chemical developments, and between 3,600 and 10,400 acres for residential needs. In contrast, the study by Woodward-Clyde maintains that only 2,446 acres are needed to accomodate service and support facilities for rigs, operation bases, gas plants, offices, and pipeline terminals.[142] While the CEQ report includes refinery and petro-chemical industrial expansion related to the OCS developments, the Woodward-Clyde study argues that refining and related downstream industries, petroleum bulk storage port facilities, related marine services, and air, road and railroad transport need none or marginal expansion. Little effect directly attributable to the OCS development program will be felt in these sectors, according to the study.[143] The acreage needed for onshore development according to the Woodward-Clyde study, is only about 0.14% of the 1,768,160 acres of the two areas studied for onshore development, and 0.008% of the more than 30 million acres in the entire Mid Atlantic area.[144]

The Woodward-Clyde study agrees that the Mid Atlantic states are experiencing now significant environmental problems. These problems may be increased by the onshore requirements of oil and gas developments, but the incremental additions to these problems is said to be generally small.[145] Locally, however, even those incremental additions may interfere considerably with alternative land use. Demand for about 500 acres in the first area studied, may be small, but pressure on available land resulting from the present trend toward rapid urbanization, will be severe. Facilities located on coastal sites may impinge on ecologically fragile or highly productive biological systems and may accelerate coastal erosion problems.[146] In the Virginia

[139] Ibid., p. 18.

[140] "OCS Oil and Gas. An Environmental Assessment." op. cit., pp. 7-31 and 7-34.

[141] "OCS Oil and Gas—An Environmental Assessment," Col. 4. op. cit., p. 4-28.

[142] "Mid Atlantic Regional Study. An Assessment of the Onshore Effects of Offshore Oil and Gas Development." op. cit., p. 20.

[143] Ibid., p. 20.

[144] Ibid., p. 20.

[145] Ibid., p. 20.

[146] "Mid Atlantic Regional Study. An Assessment of the Onshore Effects of Offshore Oil and Gas Development. Executive Summary." op. cit., p. 19.

area studies by Woodward and Clyde, some 1500 acres would be needed for onshore developments. The main onshore facilities would include operations bases, pipeline terminals, gas processing plants, service company sites, and a platform construction facility (planned by Brown & Root). The total of 1500 acres needed out of about 1 million acres occupies only 0.1% of the total land area.[147]

Parts of the study area is expected to be in growing demand due to the southward spread of urbanization. As a result, there may be increased competition for available lands by industrial, commercial, and residential land users. However, OCS land use demands are relatively small when compared to the total size of the area. Most facilities require sites with highway and rail access, and can be located in existing industrial areas along the branches of major rivers in the area.[148]

Dr. Goodman's study estimates that OCS exploration and development activities in the Mid Atlantic region would require at least 1000 acres of shoreline and nearshore upland, in addition to that already required by Brown and Root in Northhampton County, Virginia.[149] Assuming the platform production yard requires about 500 to 1000 acres, Goodman's land use figure is not too far removed from the Woodward-Clyde study's projections.

In view of the dispute over land use in the coastal zone, the acreage required to facilitate offshore developments associated with offshore petroleum developments should be looked at within the framework of total land use requirements, and compared with other forms of land use development. For example, at Chincoteague, Virginia, a legal battle is being fought between a land developer and environmentalists opposing the completion of a second-home development project in the coastal zone. The environmentalists claim that the project began with illegal dredging for canal-front lots for 4,500 homes (mainly second-homes for people working in urban areas). The land developer, on the other hand, has defended the project as a model of compatability between people who reside here and the environment. According to the environmentalists, the project will do serious damage to the coastal wetlands of Virginia, which are the spawning area for major fisheries.[150]

While a second-home development project cannot be compared with onshore oil and gas developments, especially from the aesthetic point of view, comparison of major oil-related developments and this second-home project provide an interesting inside in land use requirements for offshore petroleum developments in the Mid-Atlantic region. The study by Woodward-Clyde on onshore impacts of offshore oil and gas developments in the Mid-Atlantic region suggests that total acreage of land needed for all onshore facilities related to the Mid-Atlantic lease, will amount to about 1,768 acres. This compares with 1,865 acres for the Chincoteague second-home development. The bulk of the onshore facilities, including a platform production yard were projected for the State of Virginia (1500 acres). The study also indicated that some 5400 people associated with those developments would be relo-

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[147] "Mid Atlantic Regional Study, An Assessment of the Onshore Effects of Offshore Oil and Gas Development," op. cit., p. 172.
[148] Ibid., p. 174.
[149] "Decisions for Delaware: Sea Grant Looks at OCS Development," op. cit., p. 35.
[150] Washington Post, January 12, 1976.

cating in Virginia. In terms of land use, the land needed for the Chincoteague second-home development would be larger than total land required for oil-industry related onshore facilities in the State of Virginia. The relocated population in Virginia associated with employment created by the OCS development would be lower than the seasonal population gained by the second-home development. In view of the fact that most of the second-home owners of the Chincoteague project will be seasonal dwellers, state services are likely to be smaller than those required to meet the needs of the relocated population.

The comparison does, however, show that a single second-home development can affect land use and population patterns in the coastal zone as much as a major onshore oil-related industrial development. The issues of oil-related industrial development are often clouded by emotionalism, but should instead be considered within the general framework of competitive coastal zone land use, and land use priorities to be determined by the coastal state and the nation as a whole.

South Atlantic

In the South East Atlantic, the Southeast Georgia Embayment offers the best potential for OCS oil and gas accumulation. In contrast to Georges Bank and the Baltimore Canyon, the Southeast Georgia Embayment is near shore, which could cause an adverse aesthetic impact if oil and gas is discovered.

The 1974 CEQ report maintains that onshore effects of OCS development could be of greater magnitude in the Southeast Georgia Embayment region than in any other OCS area.[151] Onshore impacts could be particularly significant in the Charleston, South Carolina and Jacksonville, Florida areas, according to the study. Depending on the volume of oil and gas found (high or low impact), employment in Charleston, South Carolina could increase by between 12,900 and 59,200 in 1985, and between 13,600 and 75,800 by the year 2000.[152] Regional employment could grow between 17,200 to 87,900 in 1985, and between 19,200 and 109,000 by the year 2000.[153]

In Jacksonville, Florida, the number of jobs related to OCS development in the South Atlantic could grow between 9,800 and 37,000; regional employment in North East Florida and South East Georgia could increase by 12,800 to 53,900 in 1985. Comparable figures for the year 2000 are: between 8,500 and 58,700 for Jacksonville, and between 11,400 and 84,600 for the region.[154]

Acreage needed to facilitate onshore developments would range from 6,700 to 26,000 for Charleston in 1985, and between 5,900 and 29,600 for Charleston by the year 2000. The Eastern South Carolina/Eastern Georgian region would require between 14,400 and 64,600 acres in 1985: and between 13,900 and 74,400 acres by the year 2000. For Jacksonville, land required to meet onshore needs would range between 7,800 and 25,400 in 1985; and between 5,600 and 33,300 by the year 2000. Regional needs in North East Florida and South East Georgia would range from 11,500 to 43,200 acres in 1985 to between 10,700 and 64,900 acres by the year 2000. For each of the quoted regions

[151] "OCS Oil and Gas, An Environmental Assessment," op. cit., p. I-20.

[152] "OCS Oil and Gas, An Environmental Assessment," volume 4, op. cit., pp. 5A-19 and 5A-20.

[153] Ibid., pp. 5A-21 and 5A-22.

[154] Ibid., pp. 5B-20 and 5B-21.

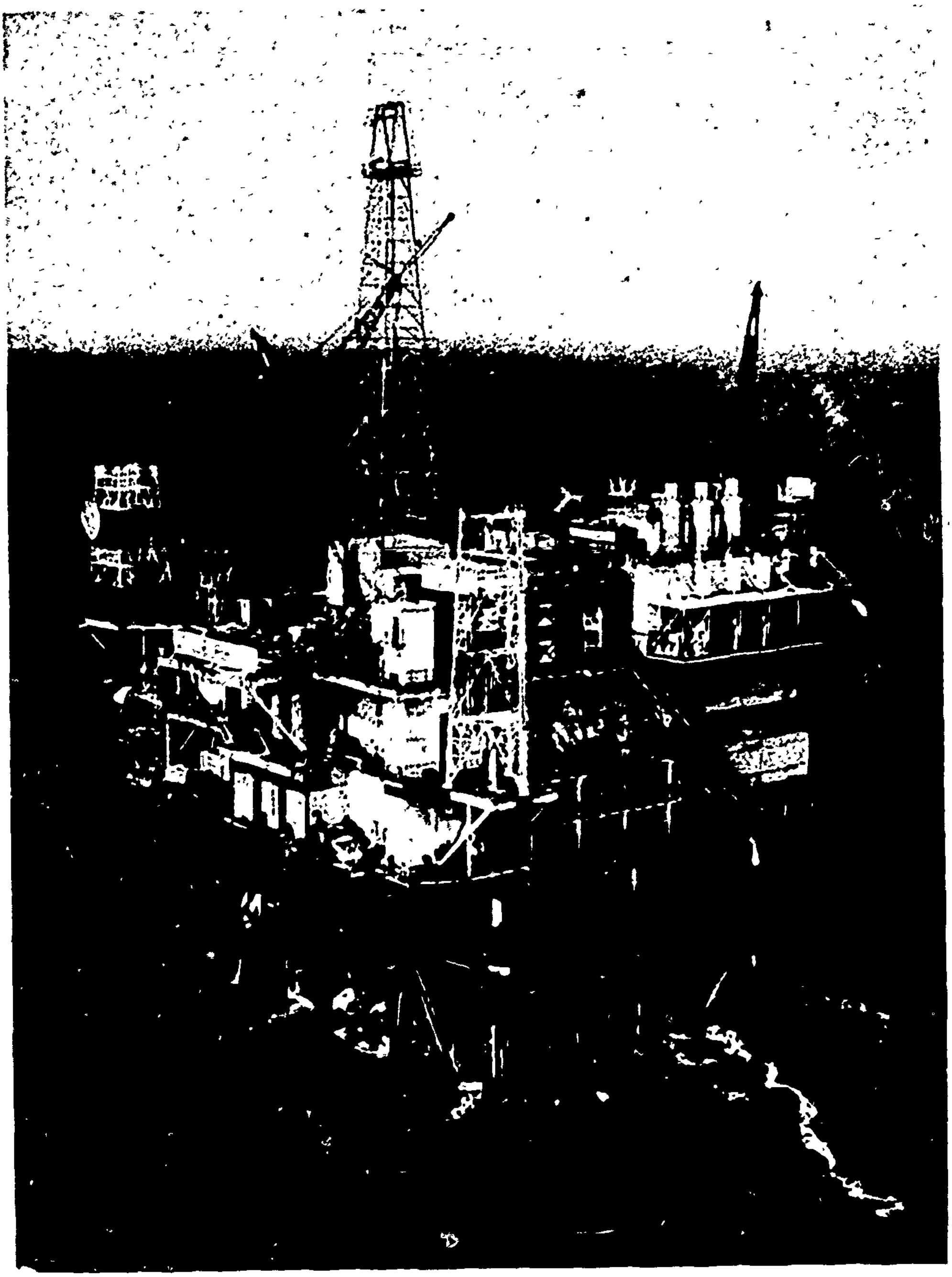
and localities, land use includes commercial, industrial and residential needs.[155]

The CEQ report concluded that the city of Charleston could double in population, because most industrial and commercial activity in support of refining and petrochemical industry would be expected to locate in or near the city because it is the only major metropolitan area within the surrounding region.[156]

It is clear that if the CEQ study were correct and a large volume of oil and gas would be discovered beneath the Southeast George Embayment, the impact would be very significant indeed. The study projects that up to 37,000 new houses would have to be built (demanding over $1 billion in mortgage financing) along with schools, utilities and other public services. And, accordingly to the study, cultural, natural, and historic resources could be threatened.[157] In the Jacksonville area impacts would also be very substantial, but in view of the already extensive growth in that city and the fact that the existing infrastructure is better equipped to plan for and assimilate the additional population, Jacksonville could accommodate high OCS impacts more readily than Charleston.[158]

No other major impact studies related to offshore oil and gas developments in the South Atlantic region, have been completed. It seems, however, that in view of the fact that employment and land-use figures, for the Gulf of Alaska and the North and Mid Atlantic, quoted in the same CEQ report, are very much on the high side, actual onshore impacts related to OCS petroleum developments in the South Atlantic region are likely to become much less significant than the CEQ report would suggest.

[155] Ibid., pp. 5–25 and 5–26.
[156] "OCS Oil and Gas. An Environmental Assessment," op. cit., p. I–20.
[157] Ibid., p. I–20.
[158] Ibid., p. I–21.



One of the four-multi-well production platforms installed by BP over the approximately 35 square mile area of the Forties oilfield. A total of 108 wells will be drilled from the platforms into the oil bearing rocks over 7000 feet beneath the seabed. These steel structures are the largest of their kind in the world and have been designed to stand in 400 feet of water and to withstand wave heights of 94 feet and wind velocities of over 130 m.p.h.

The impact of offshore oil and gas exploration and production, other industrial and non-commercial development on the coastal zone, has taken on such dimensions, that planning of such activities and management of coastal zone resources has become imperative. Recognizing the urgency of the matter, Congress passed the Coastal Zone Management Act in the fall of 1972, and the President signed it into law on October 28 of that year. The Coastal Zone Management Act is designed to encourage coastal States to develop tools for the long-term planning and management of invaluable and irreplaceable coastal resources. To achieve these laudable goals, the Coastal Zone Management Act deserves to be funded to the full amount ($30 million) provided for in the law.

Historical Background

Prior to the 1960's there was little awareness of the adverse effects of man's activities on the coastal zone. States played a relatively passive role in coastal zone matters, which were thought to be essentially local in nature. Through the zoning power, local governments acted as they saw fit with regard to the use of the coastline. Traditionally, coastal zone management efforts separated approvals for port development, drainage of wetlands and growth of communities, from controls over the projects, such as dredging restrictions and water quality controls. Different agencies dealt with different types of controls, which normally came long after the projects had been planned. Traditional coastal zone management also focused on a single resource at a time, such as fish, agriculture, ground water, or oil production, and activities lacked long-term goals. Since there were no goals, governments and private individuals competed against each themselves for short-term advantages. Gradually, during the late 1950's and early 1960's, coastal States became aware of the interdependence of various uses of the coastal zone, and of the fact that local decisions could have repercussions that reach far beyond local jurisdiction. The degradation of bays, harbors, estuaries, wetlands, etc., had clearly reached a point where conflicting uses of the coastal zone had to be reconciled.

Need for Coordinated Planning

In the past, jurisdiction over the coastal zone was left entirely to local authorities through the zoning power. Growing pressure on the coast from many onshore and offshore activities, and the realization that these developments could mutually affect each other over a wide area, have produced widespread concern. Rapid developments along the coast raised the question of whether due consideration was being given to environmental preservation and cultural and esthetical values. Gradually, the need for a broader perspective became evident, and Congress recognized this need after several years of debate by passing the Coastal Zone Management Act of 1972.

The need for coordinated comprehensive planning can be illustrated with a few examples.

1. The ecological and economic value of wetlands goes far beyond the local community. If large areas are filled and developed, the loss of these ecosystems can cause damage to wildlife and fisheries, and may also interfere with natural waste treatment. Upstream commu-

nities which previously relied on natural waste treatment in the wetland area may have to make large investments in waste treatment facilities once the wetlands have been filled. Hence, coastal wetlands are of local regional and national importance.

2. Rapid industrial development in particular local communities, may upset traditionally stable communities in the same region. An area much larger than the local community may be disrupted by the influx of new people and by employment shifts.

Comprehensive planning and assessment of the consequences of the various competitive uses of the coastal zone require resources and technical expertise not always available in small communities. Moreover, as the impact of coastal zone development frequently goes beyond the interest of a local community, there is a need for a State policy as well. States, in turn, may need to cooperate on a regional basis to consider siting of onshore facilities whenever general States are adjacent to or likely to be affected by potential offshore producing areas.

The CEQ report on OCS oil and gas developments also recommended that States affected by the new OCS developments strengthen their coastal zone management programs by developing special technical expertise on all phases of offshore development and its onshore and offshore impacts.[159] According to the report, "such augmented State coastal zone management agencies should attempt to ensure that State interests and regulatory authorities are fully coordinated with Federal OCS technical and management activities, and Federal agencies should make every effort to cooperate with State coastal zone management agencies on an ongoing basis and at all stages of the management process".[160]

The 1972 Coastal Zone Management Act can serve as a tool to enable States to plan coastal zone activities in a rational way.

Purpose of the Coastal Zone Management Act

The purpose of the Coastal Zone Management Act is to assist States to protect, preserve and restore the quality of their coastal areas. Senator Ernest F. Hollings, the principal architect of the Coastal Zone Management Act, explained the purpose of the Act in the following words: "It provides States with national policy goals to control those land uses which impact upon coastal waters. The States will establish a framework for a commonsense balance between the many competing activities within the coastal zone, which range from industrial development to wildlife conservation, to recreation needs. The goal is to protect the beaches, bayous and marshes of the coastal area".[161]

The purpose of the Act is to balance economic needs with the needs to protect the coastal environment. It provides a framework for Federal-State cooperation in planning for onshore development included in part by OCS operations.

Federal-State Cooperation

The Coastal Zone Management Act revised traditional patterns of government involvement in the coastal zone. Under the new law, the day-to-day management role continues to be exercised by local authorities through their zoning power. However, the Coastal Zone Man-

[159] OCS Oil and Gas, An Environmental Assessment, op. cit., p. I-29.
[160] Ibid., p. 1-29.
[161] Congressional Record, October 13, 1972, S. 17875.

agement Act places principal responsibility for long-range planning and management with the States. It ensures that future Federal actions will be consistent with State plans and provide a means for a concerned public to become involved in the planning and decision-making process. It ecourages States to work with local governments as much as possible in the planning and implementation phases, and to work together on a multistate or regional basis to solve problems of a larger scale.

The Federal role is one of overseeing the adequacy of State planning processe, not the specifics of individual State land and water decisions. No attempt is made by the Federal government to diminish State authority through Federal preemption. Rather the aim of the Act is encourage and assist the States to assume greater planning and regulatory powers over the coastal zone. The Federal government with its expertise in several agencies is to aid State in developing land and water use programs for the coastal zone, including unified policies, criteria, standards, methods and processes for dealing with land and water use decisions of more than local significance.[162]

The Coastal Zone Management Act also requires a reordering of the Federal role to respond to the State guidelines rather than transmitting guidelines from Washington. The Coastal Zone Management Act does not require State participation; there are no sanctions or penalties for lack of State action, but instead there are two major incentives. First, to encourage the coastal States to protect shorelands and estuarine waters, the Act authorizes the Secretary of Commerce to make grants of up to two-thirds of the cost of developing management programs. The measure provides that management programs must specify the boundaries of the coastal zone, identify the permissible land and water uses within the zone and preclude uses having an adverse impact, and specify how control will be exterted over land and water uses within the coastal zone. When a management program has been developed and approved, grants of two-thirds of the cost of administrating the program can be made by the Federal government. The total amount of grant money authorized to develop State management programs is $9 million per year; administrative grants can go up to a total of $30 million per year for all States. In addition, $6 million can be made available each year to help States acquire "estuarine sanctuaries" for long-term scientific observation and analysis. Administrative grants can only be made after the management programs of States have been approved by the Federal government.

In addition to management program development and administrative grants, there is one other incentive for States to adopt a coastal zone management program. States that adopt management programs consistent with Federal guidelines gain additional leverage in dealing with the Federal government, Federal activities, or those licensed by the Federal government that affect a State's coastal zone must, in general, be consistent with the State's approved management program. This gives the States influence in dealing with the Federal government where differences of opinion exist concerning proposed Federal actions that would affect the coastal zone. OCS development is regarded as

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[162] See: Robert W. Knecht, "Coastal Zone Management—A Federal Perspective". Coastal Zone Management Journal, vol. 1, no. 1, Fall 1973, p. 127.

among the most significant Federal actions affecting the Coastal Zones. The Secretary of the Interior can withhold approval of a State's Coastal Zone management plan if the plan interferes with the "national interest" of the nation.

CEQ Recommendation

The Council of Environmental Quality has recommended that the Secretary of Commerce require that State coastal zone plans consider refineries, transfer and conversion facilities, pipelines and related development as a condition of approval of State management programs. State coastal zone management agencies and concerned Federal agencies should jointly participate in developing these portions of the plans.[163]

The CEQ also recommended that States affected by OCS development strengthen their coastal zone management programs by developing special technical expertise on all phases of OCS development and its onshore and offshore impacts. Coordination with Federal OCS technical and management activities is encouraged in the CEQ report, and it calls for cooperation between Federal agencies and State coastal zone management agencies on an ongoing basis at all stages of the management process.

Coastal Zone Management Funding

Funding of the Coastal Zone Management Act was held up by the Office of Management and Budget until almost a year after its enactment. In late 1973, funds were released and NOAA awarded grants to 29 states for the development of coastal zone management programs.

TABLE 8.—COASTAL ZONE MANAGEMENT GRANT AWARDS

State	Federal share	Matching share	Total program
SEC. 305 (FISCAL YEAR 1974)			
Rhode Island	$154,415	$77,208	$231,623
Maine	230,000	115,000	345,000
Oregon	250,132	169,567	419,699
California	720,000	928,653	1,648,656
Mississippi	101,564	50,782	152,343
South Carolina	198,485	100,015	298,500
Washington	388,820	194,410	583,230
Massachusetts	210,000	105,000	315,000
Ohio	200,000	166,300	366,300
Alaska	600,000	360,000	960,000
Texas	360,000	191,648	551,648
Wisconsin	208,000	146,000	354,000
Pennsylvania	150,000	75,000	225,000
Minnesota	99,500	49,750	149,250
Michigan	330,486	203,961	534,447
Maryland	280,000	185,765	465,765
Connecticut	194,285	130,359	324,644
New Hampshire	78,000	39,000	117,000
Hawaii	250,000	125,000	375,000
Georgia	188,000	115,400	303,400
Delaware	166,666	83,334	250,000
Florida	450,000	236,000	686,000
Alabama	100,000	50,000	150,000
North Carolina	300,000	200,000	500,000
Illinois	206,000	103,000	309,000
Louisiana	260,000	134,090	394,090
Puerto Rico	250,000	125,000	375,000
New Jersey	275,000	137,500	412,500
Total	7,199,353	4,597,742	11,797,095

[163] CEQ, op. cit., p. 1-30.

State	Federal share	Matching share	Total program
SEC. 305 (FISCAL YEAR 1975)			
Alabama	$120,000	$60,000	$180,000
California	900,000	450,000	1,350,000
Georgia	349,250	191,745	540,995
Guam	143,000	71,500	214,500
Hawaii	400,000	200,000	600,000
Illinois	384,000	192,000	576,000
Indiana	220,000	110,000	330,000
Louisiana	342,000	171,000	513,000
Maine	328,870	164,435	493,305
Maryland	400,000	208,600	608,600
Massachusetts	382,000	204,812	586,812
Michigan	400,000	200,000	600,000
Minnesota	150,000	75,000	225,000
Mississippi	127,038	63,519	190,557
New Hampshire	120,000	60,000	180,000
New Jersey	470,750	235,375	706,125
New York	550,000	275,000	825,000
North Carolina	503,000	251,500	754,500
Oregon	298,811	154,406	453,217
Pennsylvania	225,000	112,500	337,500
Puerto Rico	350,000	175,000	525,000
Rhode Island	304,440	152,227	456,667
South Carolina	230,000	117,794	347,794
Texas	620,000	448,401	1,068,401
Virgin Islands	90,000	45,000	135,000
Virginia	251,044	125,522	376,566
Wisconsin	340,600	171,700	512,300
Total	8,999,803	4,687,036	13,686,839
SEC. 305 (FISCAL YEAR 1976 TO DATE)			
Alaska	1,200,000	600,000	1,800,000
Connecticut	290,000	145,000	435,000
Delaware	345,000	172,500	517,500
Florida (pending)	696,000	348,000	1,440,000
Ohio (pending)	500,000	250,000	750,000
Washington	500,000	250,000	750,000

By December 1975 no State had yet submitted a coastal zone management program to the Secretary of the Interior for approval. California completed its Coastal Zone Plan, which will be submitted to the California Legislature. If and when the California Legislature adopts the Plan, it will be submitted to the Secretary of the Interior. Once the Secretary has approved a State's coastal zone plan, the State will be eligible for section 306 grants. A State may propose a segmented plan under section 306. Having completed a coastal zone management program for a certain geographic region within the State, the State may be eligible for an administrative grant. One State, Washington, has received preliminary approval of completed portions of its plan. In addition to California, the States of Maine, Oregon and Michigan are nearing completion of their coastal zone plans. Seventeen states are in the second year of program development, and eight are in their first year.

The fact that funding of the Coastal Zone Management Act was held up until a year after its enactment, has caused some problems for coastal states. It takes about three or more years to complete a plan and receive approval from State Legislatures and the Secretary of the Interior. The Senate has passed an amendment to the Coastal Zone Management Act which, among others, would give the states a fourth year for program development, if needed.

Coastal Zone Management Act Revision

It was not until the Arab oil embargo occurred that state governments realized the intensity of the development pressures on the coastal zone. The Federal Government proposed an accelerated OCS development program as part of an overall plan to reduce US dependence on foreign oil. The prospects of accelerated OCS oil and gas lease activity, along with growing energy facility requirements and the imminent construction of deepwater ports, add to the challenge of bringing rational management to the coastal zone. Senator Ernest F. Hollings of South Carolina introduced S. 586, a bill to amend the Coastal Zone Management Act of 1972 to authorize and assist the coastal states to study, plan for, managė, and control the impact of energy facility and resource development which affects the coastal zone, and for other purposes. On July 16, the Senate, by a vote of 73–15, approved the bill.

On February 27, 1975, a counterpart to S. 586 was introduced in the House of Representatives (H.R. 3981), and a number of other bills calling for revision of the 1972 CZM Act followed soon thereafter.

The major provisions of those bills are:

Provisions under section 307 of the CZM Act of 1972 give coastal states with approved CZM plans the power to review proposed Federal licenses or permits to conduct an activity affecting land or water uses in the coastal zone of a state, in order to insure that such activities comply with the State's approved CZM plan, and that such activities will be conducted in a manner consistent with the plan. Amendments to the 1972 CZM Act add "leases" to licenses and permits. This means that the amended CZM Act would give coastal states with approved CZM plans the power to review proposed Federal leases for OCS oil and gas, by requiring the Secretary of the Interior to seek certification that the lease is consistent with the state's CZM plan.

Set up a coastal energy facility impact fund for grants and loans to states facing coastal impacts from Outer Continental Shelf Development or other major energy facilities. The grants and loans to affected states would go both for planning and for funding efforts to reduce or compensate for the adverse impact of development or to provide public facilities and services made necessary by the development.

Authorize $200-million annually for the fund in fiscal 1976, 1977 and 1978—and $50-million for the transition quarter.

Define the impacts for which the money would be provided as the result of a federal license, lease or permit for exploration or development of energy resources or for the location, construction or operation of an energy facility: specified that the impact must occur within the coastal zone, although the activities causing the impact need not be located there.

Allow retroactive compensation for adverse coastal impacts from offshore oil and gas development during the first five years after enactment of S. 586.

Authorize an automatic grant program for coastal states in an amount for each state tied to the volume of oil or gas landed in the state and/or produced on adjacent offshore lands and the number of years this activity has gone on and affected the state's coastal zone. The funds for these grants would come from the general treasury, subject to congressional appropriations, and were to ameliorate adverse impacts of energy resource development.

Authorize $100-million annually for the automatic grants in fiscal 1976, 1977 and 1978.

Authorize federal guarantees for state or local bonds issued for construction of public facilities or other projects to cope with the adverse impact in the coastal zone of energy development.

Encourage interstate cooperation in coastal management by authorizing interstate compacts for this purpose and by providing 90 per cent annual grants for interstate coordination—authorized at $5-million per year for fiscal years 1976–1985.

Provide special funds for research and training in coastal zone management.

Revise the federal-state proportion of funds for coastal zone management programs to increase the federal share to 80 per cent from 66 and ⅔ per cent; increase authorized funding for program development from $12- to $20-million and for implementation from $30- to $50-million per year.[164]

CHAPTER VII. THE EFFECTS OF UNITED STATES OUTER CONTINENTAL SHELF DEVELOPMENT ON THE FISHING INDUSTRY

As a result of the increasing demand for energy resources in the United States, and the development of technology necessary for the exploitation of those resources, much attention is being devoted to the development of Outer Continental Shelf (OCS) oil and gas deposits. Of great concern is the impact to the coastal zone resulting from OCS oil and gas development. In particular, the members of the fishing industry are concerned about how they will be affected by such development.

Although there has been prior OCS oil and gas development in the United States, the development has been restricted to the Gulf of Mexico and Southern California, and only recently has been extended to Alaska. Very little research has been conducted in these areas to determine the relationship of OCS oil and gas development to the fishing industry. Spokesmen from the oil industry point to benefits to fishermen, whereas fishing industry spokesmen speak of conflicts and declining fisheries.[1]

Outside of the United States, the effect of OCS oil and gas development on the fishing industry has received some attention, particularly in the North Sea, which supports an extensive fishing industry, and which has undergone a decade of oil and gas development.

OCS oil and gas development is proposed for extensive areas of the contiguous United States including the famed Georges Bank area off New England (fig., page 234), as well as for large areas off Alaska (fig., page 235). In all of these areas there are extensively developed fisheries. Georges Bank and certain areas offshore of Alaska are among the most intensively exploited fishing grounds in the world. Baltimore Canyon and adjacent Middle Atlantic areas, proposed for future OCS oil and gas development, support several important fisheries.

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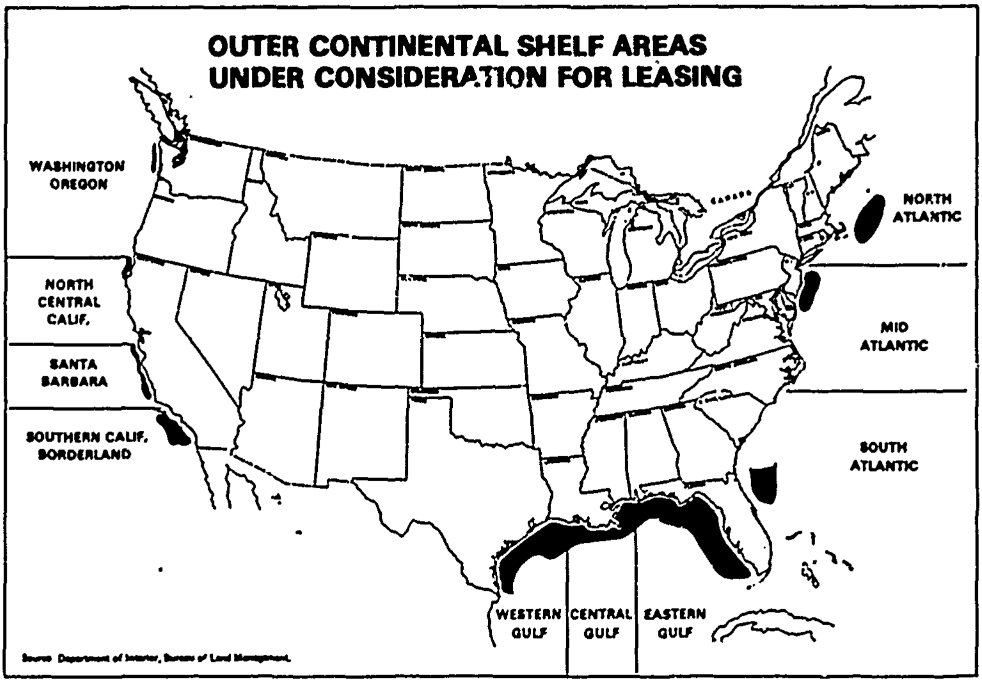
[164] See Congressional Quarterly Weekly, July 26, 1975, p. 1637.

[1] "Hearings on Outer Continental Shelf Oil and Gas Extraction and Environmental, Economic, and Social Impact upon the Coastal Zone Before the National Ocean Policy Study of the Senate Committee on Commerce," 93d Cong., 2d Sess., ser. no. 93-99, at 203 and 302 (1974).


OUTER CONTINENTAL SHELF AREAS
UNDER CONSIDERATION FOR LEASING
WASHINGTON
OREGON
NORTH
CENTRAL
CALIF.
SANTA
BARBARA
SOUTHERN CALIF.
BORDERLAND
NORTH
ATLANTIC
MID
ATLANTIC
SOUTH
ATLANTIC
WESTERN
GULF
CENTRAL
GULF
EASTERN
GULF

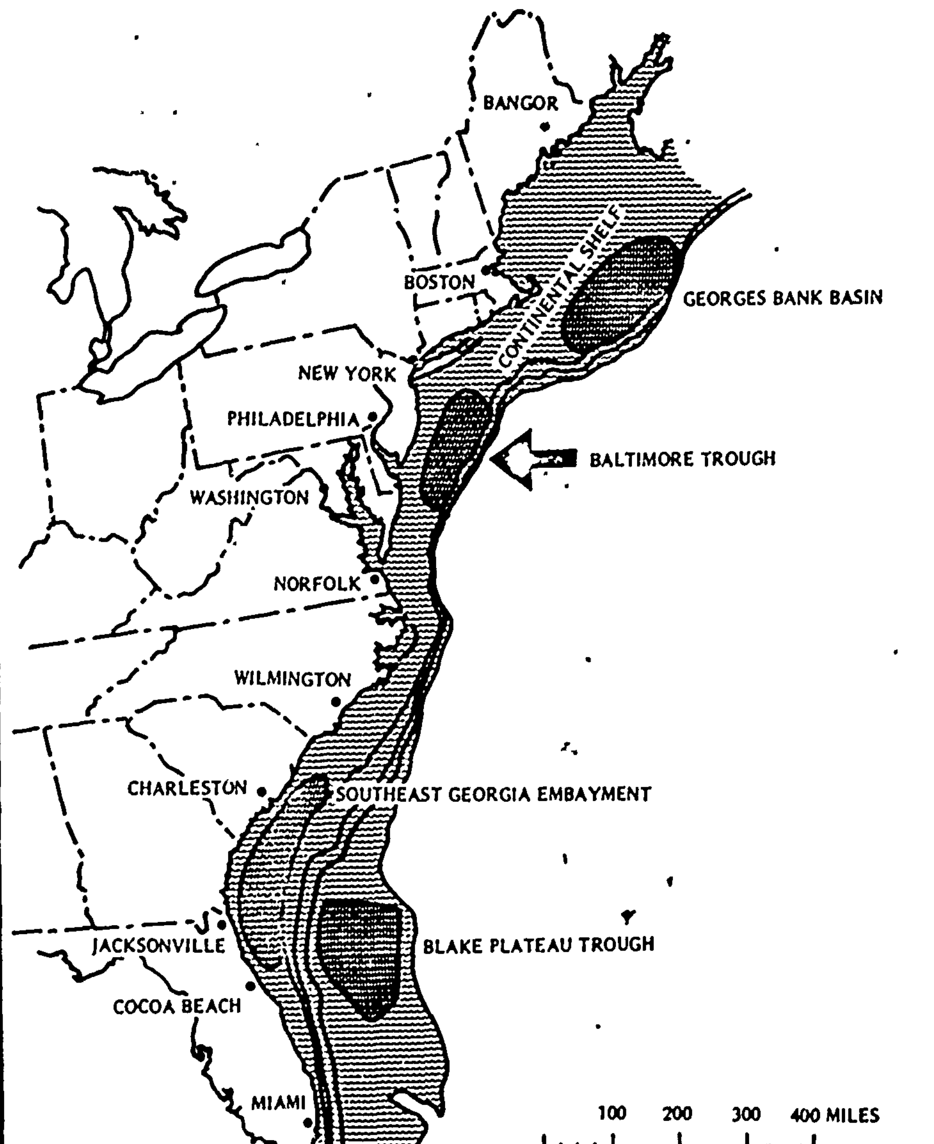
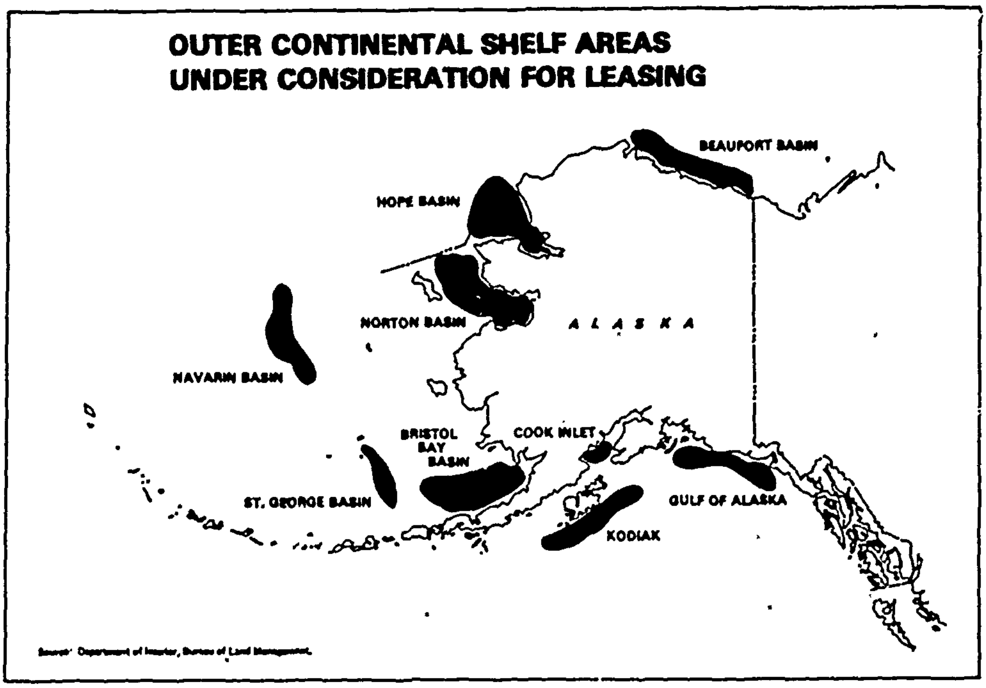


Figure 9. Location of Potential Atlantic Oil and Gas Resources



Source: Marine Advisory Services, University of Delaware Sea Grant Program.

Differences in geography, geology and culture may cause extensive differences in the impact of OCS oil and gas development on the fishing industry. Therefore, the United States is divided into five regions for the purpose of relating OCS development to the fishing industry. The regions are (1) Gulf of Mexico; (2) Georges Bank and New England; (3) Middle and South Atlantic Coast; (4) Southern California; and (5) Alaska.

The impact of OCS development on the fishing industry can be divided into two components: (1) direct effects; and (2) indirect effects. Direct effects are those which involve immediate conflict, such as physical encounters of fishing vessels with oil vessels or fixed structures. Indirect effects are those which are not immediately discernable, but which may result in profound consequences at some future time. Indirect effects are destruction of spawning grounds, chronic pollution, loss of port facilities, and loss of personnel to the high-wage oil industry.

1. GULF OF MEXICO REGION

Oil exploitation has existed in the Gulf of Mexico for three decades. Drilling has occurred in estuarine areas as well as offshore. Although there has not been a significant amount of research conducted relating oil and gas development to the fishing industry, enough interaction has occurred to highlight major issues in contention.

A. Direct effects of oil and gas development on the fishing industry

Oil industry spokesmen cite the OCS developments in the Gulf of Mexico region as a prime example of the peaceful and beneficial coexistence of the oil and fishing industries. Offshore platforms have afforded protection to fishing vessels during storms. In emergencies oil industry craft have aided in search and rescue, and oil industry helicopters have been employed to fly fishermen to onshore hospitals. Oil platforms in the Gulf function as navigational aids to fishermen.

Shortly after the first offshore platforms were built fishermen observed that several species of fishes were concentrated around the platforms. Apparently the underwater pilings functioned as artificial reefs, providing a surface for attachment by many forms of marine algae and invertebrates. Small forage fishes were in turn attracted by the availability of food. Finally, the larger predator fishes at the top of the food chain were attracted to the man-made habitats. Several of the larger fishes were those species that were in great demand by commercial and sport fishermen. Species such as snappers, groupers, pompano, cobia and bluefish, as well as several other popular varieties were commonly caught around offshore oil and gas structures.

Within a short period of time sport fishermen as well as hook and line commercial fishermen began to concentrate their fishing efforts around the offshore structures. Today, offshore oil and gas structures are the focal point of a highly successful hook and line fishery in the Gulf of Mexico.

Despite the positive effect of offshore oil and gas structures on the hook and line segment of the Gulf fishing industry, other segments of the fishing industry are less than pleased with the impact of offshore oil and gas development on Gulf fishermen. For fishermen who trawl nets in the Gulf, offshore structures serve as obstacles which interfere with their pursuit of fish. In addition, the presence of offshore oil rigs has resulted in the loss of several miles of productive fishing grounds. Gulf fishermen are often recommended to fish at least half a mile from oil rigs, even shutdown ones, because of the chances of hanging up on or running into pipes or other related debris, such as mooring buoys and cut-off wellheads. At times, as many as a half-dozen nets have gotten hung up on one wellhead.

Gulf fishermen also complain about the navigational hazards created by unlighted pieces of offshore oil and gas equipment resulting in nighttime collisions involving fishing vessels. Many disputes in Gulf waters have also arisen out of near-collisions involving fast-moving oil industry support vessels and slower, less maneuverable fishing vessels. As a result of such conflicts fishermen have stated that gear conflict problems have been more of a problem in the Gulf than have disappearing fish.[2]

B. Indirect effects of oil and gas development on the fishing industry

The major detrimental effects of oil and gas development on the Gulf of Mexico fishing industry are those which have resulted indirectly from near-shore and on-shore support activities. The inshore Gulf of Mexico is relatively shallow, highly productive and supports well developed inshore fisheries for high-priced marine species such

[2] J. Seward Johnson Lectures in Marine Policy. Drilling for Oil off the East Coast of the United States, at 28 (May 2, 1974).

as shrimp and oysters. These species have evolved over extensive periods of time so that they are adapted to the specific characteristics of the estuarine environment in which they spend much or all of their life cycles. The estuarine ecosystem is highly complex, containing intricate food webs that are dependent on various physical and chemical factors, such as salinity, oxygen content and temperature.

Associated with the development of offshore oil and gas have been numerous nearshore and inshore activities, ranging from the dredging of channels and canals to the construction of shoreside refineries and petrochemical plants. The result of such activities has been the destruction of a significant percentage of valuable estuarine habitat previously utilized as spawning, nursery and living areas by commercial species such as shrimp and oysters. It has not been determined how much damage has resulted from original development of oil and gas in Louisiana, which occurred in inshore water, and how much has resulted from later inshore activities in support of offshore development.

In addition, changes in physical and chemical conditions resulting from inshore alterations has affected both the quality and quantity of marine life. Studies show, for example, that a result of the dredging of channels through estuaries, thereby facilitating mixing of higher salinity sea water with lower salinity estuarine water, the salt content of estuaries has increased. The increased salinity of the estuaries has resulted in a decline of those species of commercial shrimp which are intolerant of high salt content, and an increase of those commercial species which are salt tolerant. Increased salinity of estuaries has also resulted in the intrusion of oyster predators such as starfish and oyster drills which cannot survive well in low salinity waters.

It has been alleged that since the advent of oil development along the Louisiana coast oyster production has decreased substantially. years (Figure 24) indicates that total oyster production has increased by approximately 50 percent from 1950 to 1975 (8.4 to 12.3 million approximately 50 percent from 1950 to 1975 (8.4 to 12.3 million pounds), largely as the result of increased harvest of oysters on private beds. Although production of oysters on public beds has decreased substantially, the harvest of oysters on public beds is insignificant when compared to the amount harvested on private beds.

According to fisheries biologists at the National Marine Fisheries Service (private communication) there are no data supporting contentions that periodic declines in oyster productivity can be attributed to a specific activity of man (e.g. oil and gas development). However, there are periods when fresh water from the Mississippi River is diverted through coastal estuaries as a means of flood control (particularly during hurricanes), resulting in the death of oysters in those estuaries. At the same time predators of oysters (e.g. oyster drills) are also killed, resulting in higher oyster production in the affected estuaries in the years immediately following the fresh-water diversion (i.e. until the predator-prey relationships are reestablished). Public oyster beds are much more affected by such fresh-water diversions than private beds, the latter being located in choice areas which are protected from such occurrences.

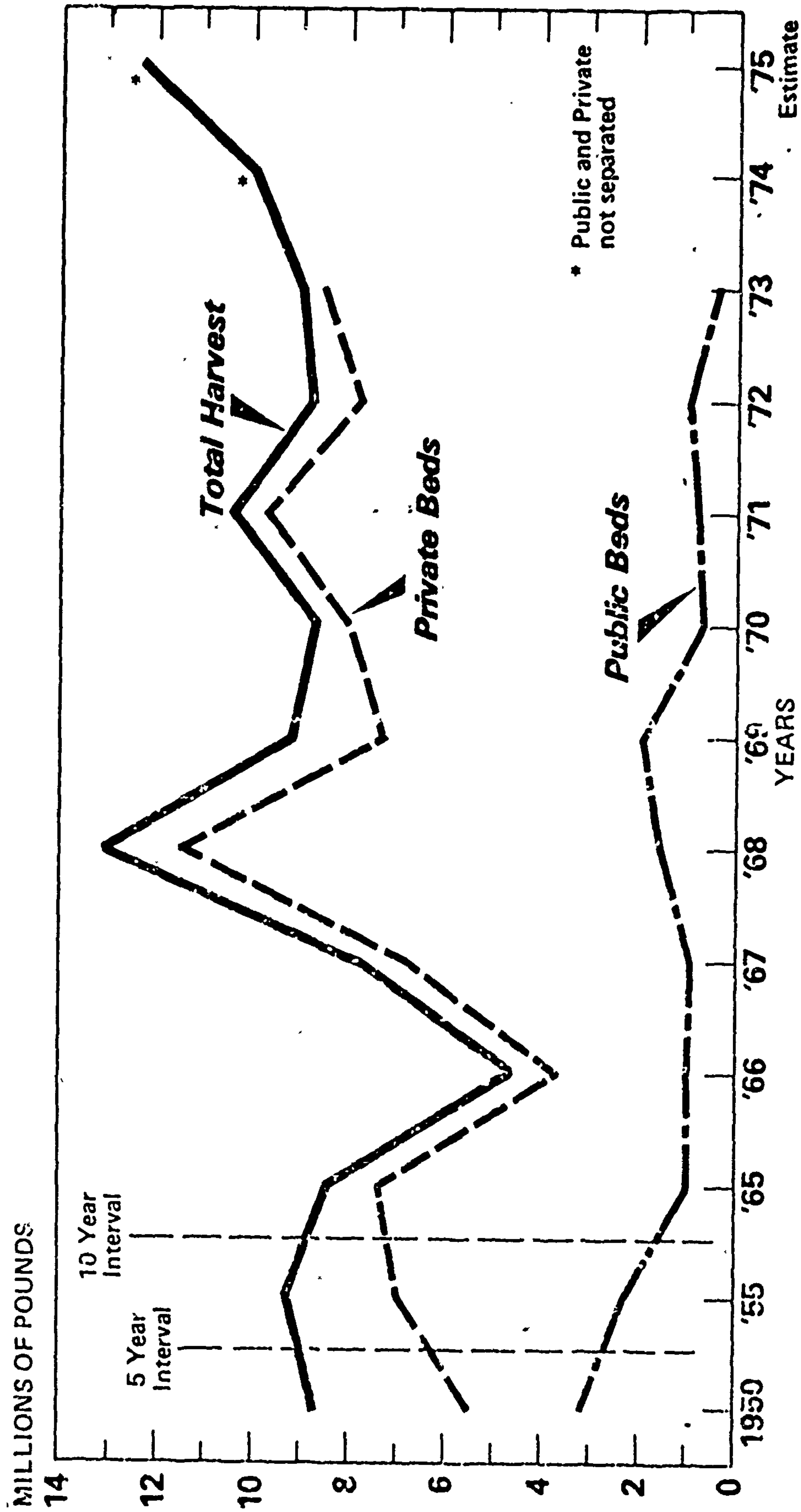


FIGURE 24.—Louisiana oyster production

2. GEORGES BANK AND NEW ENGLAND REGION

Fishermen from the Georges Bank and New England region discredit the alleged benefits to fishermen from offshore oil and gas development in the Gulf of Mexico by pointing out that conditions in the Gulf are very different from their region. For example, fishermen in the Georges Bank region state that conditions there closely resemble those of the North Sea, and suggest that experiences of fishermen there, rather than in the Gulf of Mexico, should serve as a prediction of what New England fishermen will encounter. They cite many differences between the Gulf of Mexico and the Georges Bank region which will result in different impacts of OCS development on fishing in the two regions. These differences have to do with both the geographical characteristics of the region and with the biological and social structures of the fishing industries.

The Gulf of Mexico is an essentially warm, calm body of water characterized by clear weather. Conversely, the waters in the vicinity of Georges Bank are often turbulent, and the frequent presence of fog results in greatly diminished visibility through much of the year. As a consequence, fishing vessels in the Gulf of Mexico can make do with much less navigational equipment than those fishing Georges Bank. When inclement weather occurs in the Gulf of Mexico, fishermen utilize OCS structures, either for refuge or for visual references for navigational purposes. Even in calm weather the structures are used as visual navigational aids. However, most Georges Bank fishermen do not envision similar uses for OCS structures in their area in that due to the nature of the environment their vessels are equipped for consistent navigation under conditions of poor visibility. Therefore, additional navigational benefits from OCS structures would be negligible. Some Georges Bank fishermen have indicated that OCS structures could serve a protective function during severe storms, whereby rather than having to make the full run to port, fishing vessels could find temporary refuge in the lee of some of the larger structures.

A. Direct effects of oil and gas development on the fishing industry

The major concerns of fishermen of the Georges Bank and New England region focus upon physical encounters between fishing vessels and gear and the vessels, structures, pipes and debris associated with OCS development. Much of the fishermen's information relating to such conflicts has been derived from the North Sea experience, although conflicts in the Gulf of Mexico have also contributed to their knowledge. Like the North Sea, and unlike the Gulf of Mexico, the sea floor off New England, and particularly on Georges Bank, is extensively fished. The North Atlantic sea floor is at best uneven and is often rugged and rocky. Sunken vessels add to the obstructions on the sea bottom. Strong currents flow along the sea floor resulting in constantly changing bottom configurations in sandy areas.

Fishermen who ply the waters of the North Atlantic are aware of the location of many of the obstructions on the sea floor, and are thus able to avoid them and the resultant cost and loss of time involved with snagging their trawling gear. They have also developed patterns of trawling an area which follow the bottom contours, allowing them to most efficiently fish that area.

It is feared that OCS development, particularly in the Georges Bank area, will result in the loss of extensive areas to the fishermen for the following reasons: [3]

1. The very existence of OCS structures will preclude fishing in that immediate area, and because of the disrupting effect of the structures on trawling patterns, even larger areas will be made unavailable to the fishermen.
2. Not all pipes will be buried. The exposed pipes will add to the bottom obstructions. Since the pipes will be of recent origin the fishermen will be unaware of where they are located, resulting in snagged gear. Even if pipes are buried in sandy areas, the scouring effects of the strong currents would uncover some sections of the pipes.
3. Debris strewn on the sea floor, either as a result of construction, or by being discarded by OCS support vessels, would contribute to the obstructions on the sea floor. Again, since the fishermen would not know the location of the debris, it is very probable that there would be instances where nets would come into contact with such debris. Even were the fisherman able to extricate his nets from the obstruction, valuable loss of fishing time would result. Debris in nets also presents a real physical danger to fisherman.[4]
4. Due to increased traffic caused by OCS support vessels it is likely that sea lanes will have to be established, thereby resulting in the loss of those areas to fishing. Even were sea lanes not established, since fishing boats are generally slow and clumsy and incapable of maneuvering safely, where there is extensive support vessel activitiy it is likely that fishermen will remain away from such zones.

New England fishermen cite problems encountered by North Sea fishermen as a factual basis for their fears. They refer to instances of vessel collisions, and antagonistic and impatient attitudes of OCS support vessel operators. Fishing vessels have also collided with unmarked obstructions below the surface, particularly at night. There have bave been several instances of debris being dragged up in nets. and some supply vessel operators and crews have openly stated that it's easier to discard material at sea rather than unload it at shore, thereby wasting valuable shore leave. Cargo on Gulf of Mexico vessels is unloaded by stevedores; thus, there is no incentive for operators and crews to discard such cargo at sea. However there have been several recorded incidents of fishing gear being snagged and lost on sub-surface uncapped wells in the Gulf of Mexico.

Fishermen, from New England as elsewhere, don't want to completely prohibit OCS oil and gas development, if only for the reason that to attempt to do so would be futile. However, they are con-

[3] Allen, Richard B., "N. England Fisherman Evaluates North Sea Offshore Oil Problems," National Fisherman, Oct. 1975, at 13-B.

[4] Report from the Fisheries and Offshore Oil Consultative Group, RE 41318 1500 TBLx, Scotland (1975).

cerned that such development should have as little negative, and as much positive, effect on the fishing industry as possible.

There are problems of allocating the cost of OCS development to the fishing industry. Some fishermen suggest that there should be outright reparations made to fishermen for the loss of fishing grounds, reduced productivity, and loss of fishing time as a result of OCS development. In the North Sea an arbitration board has been created, consisting of members of the fishing industries and the oil and gas industry. New England fishermen appear to feel that such a board would be very useful in determining what rights and obligations exist among the industries.

It will be necessary to have some mechanism available to determine liability for damage to the interests of the fishing and oil and gas industries, and of the public. It is not difficult to imagine the complex legal issues of liability raised if a fishing vessel were to tow its gear across an exposed pipe, thereby breaking the pipe and effectuating a massive oil spill. The fisheries spokesmen assert that oil companies are placing their structures in an environment where they would be exposed to a substantial risk of danger, i.e. unburied pipes where fishing trawlers commonly operate. They feel therefore that oil companies should be assessed full liability (i.e. strict liability) for whatever damage results from an oil mishap (e.g. an oil spill). The oil companies, understandably, feel that it would be unfair for them to assume total responsibility for the results of action that may be the result of negligence by fishermen. It's suggested that it would only be fair to have the question of liability determined in an objective forum, and that liability be assessed to the party at fault.

Not only must the question of liability be answered, but the forum in which liability will be decided must also be agreed upon. The interested parties must decide whether it would be to their benefit to have their conflicts settled in a court of law, or whether some other fair and impartial quasi-judicial or authoritative body would better suit their purposes. Court battles might result in long and costly litigation, and distribution of reparations may be delayed for several years. Small fishermen may be put out of business by virtue of the cloud of an impending lawsuit, which may dissuade lending institutions from loaning the fishermen funds until the cloud is cleared. Alternative forms of funds could be established which would permit prompt distribution of money and thereby lessen the hardship resulting from conflicts.

B. Indirect Effects of Oil and Gas Development on the Fishing Industry

It is unlikely that there will be very evident indirect effects of the fishing industry of the New England region resulting from the impact of OCS oil and gas development. In comparison with the Gulf of Mexico region, for example, the New England region is characterized by a coastal zone that is much more heavily industrialized and densely populated. The New England coastal zone was one of the first arc of the United States to be settled and has a pronounced socio-economic structure. In general there is an abundance of harbor space and related onshore service facilities. There are ample housing facilities, towns are numerous, and professional and service industries are well established. In addition, there exists a large labor pool of skilled and semiskilled workers. As the result of recent cut-backs in military programs (the military having been long entrenched in the New England economy) there are vacant harbor and housing facilities which would be easily converted to the needs of the oil and gas industry. New England has been greatly affected by the recent economic slowdown in the United States, and it is hoped that OCS oil and gas development could spur the lagging local economy.

Unlike the coastal zone of the Gulf of Mexico, which is extensive and which is characterized by highly developed, productive inshore fisheries, the coastal zone of the New England region is limited, and deep water lies close to the shoreline. Were onshore facilities to be located within the New England coastal zone, it is unlikely that there would be the impact on inshore fisheries that has resulted in the Gulf of Mexico.

It is possible, however, that certain indirect effects of OCS oil and gas development could eventually be detrimental to the fishing industry. It is possible that the oil and gas industry will draw some investment money away from the fishing industry. Some fishermen, both vessel owners (and their vessels) and crewmen will probably be lost to the higher-paying oil and gas industry. It is questionable what the net result of loss of some of those vessels presently in the fishing industry to the oil and gas industry would be, since at present the New England fishing industry appears to be overcapitalized.

OCS oil and gas development may result in increased competition for existent harbor and service facilities, thereby raising the cost for those facilities to fishermen. A decline in the quality and quantity of shoreside services to fishermen may also result. In the coastal areas of the North Sea, such as in Scotland, actual displacement of fishermen has occurred where there were not sufficient harbor facilities to accommodate both oil and gas and fishing needs. It is unlikely that such displacement will occur in New England.

An issue raised by the fishing industry is that OCS oil and gas development may not be the big boon to the New England region that its proponents suggest. They allege that the economic benefits will be few and short-lived. It is suggested that much of the skilled, high-paid oil and gas labor will be imported from the outside, and that many of the raws materials may be shipped to outside areas for refinement and processing. The cost to New Englanders of oil and gas may remain unaffected, even though such materials are derived off their coast. The oil and gas production phase may be relatively short-lived, perhaps lasting only forty years. Those opposed to offshore oil and gas development suggest that there may be no permanent benefits from such development to the New England region. However, since fisheries, if managed properly, would exist forever, it is questioned whether it is the best interest of New England to permit harm to occur to fisheries as a result of short-term oil and gas development. As an example, although the probability of a massive oil spill is slight, and even though there are no provable harmful effects on marine organisms as the result of oil spills in the natural environment, the chronic effects of oil on marine organisms are still highly questionable, and in fact may be very harmful. Recent studies have shown that certain life stages of marine organisms are highly susceptible to low levels of oil in sea water. Particularly susceptible are the planktonic larvae and juvenile stages of many commercial species. The commercial species of finfish and shellfish inhabiting Georges Bank and other new England waters have complex larval and juvenile stages characterized by extensive planktonic periods.

Sea life in the New England region may be already exhibiting the effects of chronic pollution of the marine environment. Diseased organisms have begun to show up in catches. Some fishermen suggest that oil and gas development should be delayed until fisheries scientists have had sufficient time to determine the effects of oil pollution on the marine environment.

3. MIDDLE AND SOUTH ATLANTIC COAST REGION

The effect of OCS oil and gas development on the fishing industry on the Middle and South Atlantic Coast of the United States is at best highly conjectural. The offshore picture is more analogous to that of the Gulf of Mexico than that of the New England region. The width of the Continental Shelf is extensive throughout the region with the exceptions of the offshore areas adjacent to the Outer Banks of North Carolina and Southeast Florida. The inshore areas of the Middle and South Atlantic Coastal region are characterized by extensive estuaries consisting of many large bays, tidal flats and salt water marshes.

Considerably more bottom trawling takes place in the Middle Atlantic Coastal region than in the Gulf of Mexico. The fisheries of the South Atlantic Coastal region and the Gulf of Mexico are similar.

A. Direct effects of oil and gas development on the fishing industry

The direct effects on the fishing industry of OCS oil and gas development in the Middle and South Atlantic Coastal region will probably lie somewhere between the effects experienced by Gulf of Mexico fishermen and those feared by New England fishermen. The waters of the Middle and South Atlantic coasts are considerably calmer than those of New England. Much of the sea bottom off the Middle and South Atlantic region is covered by sand, and it is likely that oil platforms would form the same type of "fish oases" that they do in the Gulf of Mexico. However, since there is considerably more bottom trawling that takes place in the Middle and South Atlantic region than in the Gulf of Mexico, it is likely that there would be many more gear conflicts occurring in the former region.

The problems of dispute settlement and the questions of liability, particularly in those situations where the public interest is affected (e.g. oil spills), are the same in the Middle and South Atlantic region as they are in the New England and Georges Bank region.

B. Indirect effects of offshore oil and gas development on the fishing industry

The coastal zone of the Middle and South Atlantic Coastal region is comprised of extensive areas of estuarine habitat. There are many miles of bays and intertidal waters rimmed by broad zones of coastal marsh. Shallow areas of sea bottom covered with vegetation (grass flats) provide habitats for many species of finfish and shellfish of great commercial value. This inshore region is a leading producer of crustaceans (e.g. shrimp and crabs), mollusks (e.g. clams, oysters and scallops) and fishes (e.g. pompano, channel bass, mullet, croakers, bluefish, weakfish, spanish mackerel and striped bass). Inshore fisheries, as in the Gulf of Mexico, are highly developed.

Although there are some excellent harbors which are well developed and are employed for multiple uses, i.e. Baltimore, Norfolk and Charleston, it is likely that the development of OCS oil and gas would result in extensive and heavy additional development in present harbors, or would result in the development of virgin coastal areas. The result of such development on inshore species, and subsequently the fisheries based on those species, could be exceedingly detrimental. Even were individual species not themselves harmed, the concentration of pollutants in such sedentary filter feeders as oysters and clams could make them unfit for human consumption, thereby rendering them useless to the commercial fishing industry.

As in the New England and Georges Bank region, where OCS oil and gas development has not yet begun, Middle and South Atlantic Coast fishermen want assurances that OCS development will not be detrimental to the fishing industry, and if it is determined that such development will be detrimental, they desire that mechanisms be set up which will compensate them for losses sustained by the fisheries.

It is not anticipated that OCS oil and gas development activities will result in noticeable economical, financial or social displacement of fishing industries in the Middle and South Atlantic Coastal region. Some coastal areas have a substantial number of unemployed skilled and semiskilled workers who could be employed in OCS-supportive industries. There may be some loss of fishing vessels and crews to the higher-paying oil and gas industry, but as in New England the fishing industry in some areas of the Middle and South Atlantic Coastal region is overcapitalized, and in general the fishing industry in those areas might benefit from some attrition.

4. THE SOUTHERN CALIFORNIA COASTAL REGION

The Outer Continental Shelf of the Southern California Coastal region was the first to be exploited for oil and gas development. The first wells were sunk in the Santa Barbara Channel in the late eighteen-hundreds. In addition, many natural oil seeps or leakages are endemic to the region. It is likely that through evolutionary adaptation to oil in their environment, many marine species in the areas of chronic oil leakage are tolerant to fairly high levels of oil concentration. In effect, they "have learned to live with oil."

The Continental Shelf of Southern California is narrow, and inshore commercial fisheries are not highly developed nor of major economic importance to the region. In addition, Southern California is the home port of the financially lucrative distant-water fishery for tuna and other highly migratory species of fishes.

As a consequence of the above factors, not much research has occurred in relating the effects of oil and oil development on marine species or the fishing industry of the Southern California Coastal region.

A. Direct effects of offshore oil and gas development on the fishing industry

Fishermen and fish in the Southern California Coastal region have been "living with oil" for a long time (the first offshore wells were drilled in the Santa Barbara Channel in the late 1800's). Additional OCS oil and gas development would not appear to substantially increase gear or vessel conflicts between the oil and gas and the fishing industries. The lack of a significant Continental Shelf and of significantly developed fisheries also minimizes the opportunity for conflicts between the industries. In addition, there is a significantly developed recreational hook and line fishery for pelagic species such as Pacific yellowtail and albacore as well as various bottom-dwellers such as the rockfishes. Such sought-after species commonly congregate around offshore oil structures.

B. Indirect effects of oil and gas development on the fishing industry

The Santa Barbara Channel was the sight of one of the world's most massive oil spills. As a result of the spill an oil-drilling moratorium was declared which resulted in the cessation of additional oil development for several years. Although the moratorium has been lifted little research has occurred relating the effects of oil (drastic or chronic) on commercial marine species and their associated fisheries.[5] As in other regions of the United States, fishermen suggest that extensive research be undertaken to determine the effects of oil (particularly the chronic effects) on marine species before extensive additional OCS oil and gas development proceeds.

5. THE PACIFIC COAST REGION

The Pacific Coast region is currently the most unlikely to undergo extensive OCS oil and gas development. As a consequence, fishermen in this region have generally paid little attention to potential conflicts between the oil and gas and the fishing industries. The Continental Shelf in this region is narrow, and there are not intensively-developed commercial trawl fisheries. Beyond three miles (the territorial sea) foreign fisheries for such species as hake, rockfishes and black cod are more highly developed than United States fisheries However, as a result of proposed extended United States fisheries jurisdiction to 200 miles offshore (such legislation is now pending before Congress), were such jurisdiction to take effect, the United States-foreign fishing picture offshore of the Central Pacific could change radically within a few years.

A. Direct effects of offshore oil and gas development on the fishing industry

Were gear and vessel conflicts to arise between the oil and gas and the fishing industries they would be of the type anticipated by fishermen in the New England and Georges Bank region, and in the Middle and South Atlantic Coastal region. As in the those regions it is hoped that some mechanism would be created to promptly resolve jurisdic-

[5] One rather good report was the California Department of Fish and Game Interim Report on the Santa Barbara Oil Leak of December 15, 1969.

tional issues and provide an objective arbitration medium that would result in fair and speedy judgments.

B. Indirect effects of offshore oil and gas development on the fishing industry

The Pacific Coastal region contains many miles of undeveloped coastline broken by large deep harbors, e.g. Portland and Seattle. There are no highly developed inshore commercial fisheries in which extensive harm is feared as a result of OCS oil and gas-related activities. It is unlikely that severe displacement of fishing industries would occur as a result of OCS oil and gas development in the Pacific Coastal region.

6. THE ALASKA REGION

Offshore oil and gas development is a relatively new experience to Alaska. The first offshore wells were drilled in Cook Inlet during the 1960's. Since then several additional wells have been drilled. Over a dozen working platforms to which the wells are connected have been constructed. Over one-hundred thousand acres of Alaskan sea bottom have either been leased to oil and gas companies or have been proposed to be offered for lease by the state of Alaska.

No portion of the Alaskan outer continental shelf has been leased by the Federal Government. Presently 1.8 million acres in the Northeast Gulf of Alaska are under consideration for leasing, and an enviromental impact statement for that area has been prepared. Presently up for consideration are: (1) the St. George Basin of the Bering Sea; (2) the Kodiac area of the Gulf of Alaska; and (3) Cook Inlet. Comments and nominations by parties interested in the Kodiac area of the Gulf of Alaska were to be received by December 29. Comments and nominations for the Cook Inlet area have already been received, and tentative tract selection for that area is currently taking place.

In the decade since the advent of oil, conflicts have arisen between the fishing industry, which ranks 3rd in Alaska in economic importance, and the oil industry, which is 2nd in economic importance.

A. Direct effects of offshore oil and gas development on the fishing industry

Portions of the coastal waters of Alaska are among the most productive marine environments in the world. National Marine fisheries studies conducted on shrimp populations in Kachemak Bay in lower Cook Inlet indicate that productivity there may be ten times that of the Gulf of Mexico.

As a consequence of the high productivity of Alaskan coastal waters and the lack of development of other industries in the Alaskan coastal zone, fishing pressure in that region is intense. It is therefore understandable that on several occasions conflicts have occurred between the oil and gas and the fishing industries. For example, conflicts have arisen when vessels conducting seismic surveys for the oil industry have towed cables through areas containing crab pots. The crab pots are marked by floats attached to the pots by lengths of rope. When the seismic cables, which are four inches thick and up to one and one-half miles long, and which are equipped with plastic wings which regulate the depth of the cables, are towed through an area containing crab pots, either the lines connecting the marker floats to the buoys are broken so that the fishermen can't locate the pots, or the pots themselves are towed up by the seismic cables. Many crab pot lines connecting the pots to the surface marker buoys have also been cut when run over by oil company workboat and tug operators. Without the buoys fishermen can't locate their pots and lose them. (The lost pots continue to trap and kill crabs.)

As in the New England and Georges Bank region, Alaskan fishermen fear that increased vessel activity related to OCS oil and gas development will necessitate the creation of traffic lanes, thereby depriving them of access to many acres of valuable fishing grounds below the lanes. In a region of such intense and profitable fishing as the Alaskan Coast such loss could be extremely significant.

B. Indirect effect of offshore oil and gas development on the fishing industry

The high rate of biological productivity of much of Alaskan coastal waters is due to an unusual circular current system that concentrates food and holds the planktonic larvae of shrimp, crabs and other commercially important species through the several molting stages into adulthood. One such circular current system (termed a gyre) is located in Kachemak Bay, situated near the mouth of Cook Inlet, in an area included in a December, 1973 sale of state oil and gas leases on 98,000 acres in the lower Cook Inlet Basin. Research by the National Marine Fisheries Service has indicated that Kachemak Bay serves as the breeding ground for Cook Inlet and at least part of the Gulf of Alaska. Fisheries biologists fear that if an oil spill were to occur in the lower Cook Inlet and Kachemak Bay region, the gyral effect of the currents would keep the oil in constant contact with susceptible eggs and early larval or juvenile stages of finfish and shellfish retained within the gyral. Recent studies indicate that the impact upon one of the world's richest fisheries could be disastrous. Laboratory studies are developing an increasing amount of information which indicates that low level concentrations of water-soluble oil fractions are lethal to many juvenile forms of finfish and shellfish. Because of rough water conditions common to lower Cook Inlet, it is expected that oil released to these waters could become readily emulsified, thereby facilitating the release of water-soluble oil fractions to the water.

Whether the entrance of oil into the Alaskan marine environment is by oil spills or by chronic oil releases the harmful effect on commercially important species could be significant. Recent studies have shown that low level concentrations of oil in the marine environment can modify behavior of certain species of finfish and shellfish, including salmon and king and tanner crabs. When tanner crabs were exposed to low level concentrations of Prudhoe Bay crude oil during molting, their legs separated from their bodies leaving them immobile and unable to seek food, avoid danger and survive. During certain seasons of the year, oil spills could critically affect salmon resources. Laboratory studies using pink salmon fry have demonstrated that such fry avoid low level concentrations of water-soluble oil. Salmon fry concentrate and migrate through shallow coastal waters to feed. Oil which impacts these areas could cause salmon fry to alter their behavior and avoid important feeding and nursery habitats.

Another potential impact could be the release of nutrients to the water from chronic oil releases. Red tide organisms are common to many waters in Alaska. Toxins produced by these organisms cause paralytic shellfish poisoning (PSP). The release of additional nutrients to the system could stimulate the growth and reproduction of red tide organisms, thereby affecting the harvestability of important razor clam and other shellfish populations.

Alaskan fisheries biologists also fear the effects of oil spills upon many miles of public and commercial clam beaches. Since these organisms are filter feeders, it is likely that they would ingest oil, thereby making them unfit for human consumption.

The herring fishing industry also may be adversely affected by oil in the marine environment. Lower Cook Inlet contains important spawning habitats for herring. The Cook Inlet herring population in turn supports a growing industry. Critical to herring spawning success are areas suitable for the deposition of their adhesive eggs. Eggs are deposited on gravel substrate, or on kelp and eelgrass along the shoreline. If these habitats are impacted by oil, herring may avoid using these areas, or if the areas are used the reproduction success may be reduced. A likely area in which herring spawning would be affected is Kachemak Bay.

In 1970 Prince William Sound became Alaska's main "herring eggs on kelp" area with an annual production of nearly a quarter million dollars worth of export product. The herring eggs which adhere to the kelp are harvested and processed. The Prince William Sound "herring eggs on kelp" fishery could possibly be destroyed were the marine environment to become impacted by oil.

Fishermen and fisheries biologists in Alaska, as well as in other coastal regions of the United States, suggest that OCS oil and gas development be delayed until sufficient time has been allowed for laboratory and field testing of the effects of oil on the marine environment, and for analyses to be made of results of such tests. Until the results and analyses of such tests are available it is suggested that marine sanctuaries be created, encompassing such areas as the 5,000-acre portion of Kachemak Bay already leased, where oil and gas development will not occur.

Other indirect effects of OCS oil and gas development on the fishing industry of Alaska are related to the impact of industrial development on coastal economies which are based almost exclusively on the fishing industry. Changes in a unique way of life, attrition to the higher-paying oil and gas industry, increased competition for harbor space and services, and actual displacement are fears presently confronting Alaskan fisherman.

It may be concluded that the effects of OCS oil and gas development will differ widely among the various coastal regions of the United States. Perhaps the New England and Georges Bank region and the Alaskan region will be most affected. Although little definitive information is available on the impact of offshore oil and gas development on the fishing industry, extensive research encompassed in several studies is being conducted. The greatest fears of members of the fishing industry concern matters which relate to possible conflicts between the user groups and methods of resolving those conflicts. Many fishermen and fisheries biologists allege that they are not opposed to

OCS oil and gas development, but desire more time to prepare for the consequences of such development.

CHAPTER VIII. COMPENSATION TO COASTAL STATES FOR OCS IMPACTS

INTRODUCTION

The United States Supreme Court, in *United States* v. *California*, 332 U.S. 19 (1947), held that the coastal States with certain exceptions for Florida and Texas, were not the owners of the three-mile territorial sea around their coastal margins, and that the Federal Government, not the States, had paramount rights with full power and dominion over the seabed resources.[1]

Two years before the *California* decision, President Truman had issued a proclamation in 1945 which unilaterally declared the resources of the subsoil and seabed of the Continental Shelf as Federal property.[2]

This extraordinary extension of sovereign jurisdiction was ostensibly made to clarify the United States position in international relations; however, the force of *United States* v. *California*, coupled with the Truman Proclamation clearly divested the coastal States of any legal jurisdiction over offshore mineral resources.

The controversy over the offshore areas had come to be known as the "Tidelands controversy" and figured prominently in the States' rights issues of the 1952 national elections. With the support of the Eisenhower Administration, the 83rd Congress enacted two bills which partitioned the marginal sea between the Federal and State governments, and in effect, reversed the decision in *United States* v. *California*.

The two complementary Acts passed in 1953 first gave jurisdiction over the three-mile limit back to the States through the Submerged Lands Act of 1953,[3] and then established Federal control and a framework for administering the offshore lands lying seaward of the three-mile extension through the passage of the Outer Continental Shelf Lands Act of 1953.[4] Under the Outer Continental Shelf Lands Act, the Department of the Interior collects all rents, royalties and bonus payments from leases granted in the OCS. These revenues are deposited in the United States Treasury and are credited to miscellaneous receipts. In budgetary parlance, OCS revenues are considered negative expenditures, and therefore may offset budget deficits. Amounts received from areas which are disputed under claims by the states, several of which remain unresolved even after the *California* and *Maine* decisions, are held in escrow until such time as their fate is determined by the courts or resolved through Federal-State agreements.

Revenues derived by the Federal Government from the OCS leasing activities since its implementation in 1953 total $18.2 billion. Annual revenues from OCS lands are shown in Table 9.

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[1] The Supreme Court reaffirmed its position with regard to 12 Atlantic Coast States in *United States* v. *Maine*, et al. U.S. (1975).

[2] Presidential Proc. 2667, Sept. 28, 1945, 3 C.F.R. 67 (comp. 1943–1949).

[3] Submerged Lands Act of 1953, 43 U.S.C. §§ 1301–1315 (1970).

[4] Outer Continental Shelf Lands Act of 1953, 43 U.S.C. §§ 1331–1348 (1970).

TABLE 9.—*Annual revenues from leases on OCS lands* [1]

Year:	*Total*	Year—Continued	*Total*
1953	$2,358,172	1965	146,445,876
1954	147,660,265	1966	354,465,657
1955	117,197,082	1967	675,859,202
1956	11,715,526	1968	1,558,052,293
1957	14,840,216	1969	362,029,240
1958	20,150,076	1970	1,238,960,760
1959	118,828,715	1971	465,012,307
1960	323,781,831	1972	2,624,957,875
1961	51,345,414	1973	3,949,981,440
1962	564,569,574	1974	5,598,758,447
1963	98,963,285		
1964	194,939,272	Total	18,176,872,025

[1] U.S. Department of the Interior, U.S. Geological Survey, Conservation Division, outer Continental Shelf Statistics, 1953 through 1974. Washington, U.S. Govt. Print. Off., 1975, p. 49.

Under the accelerated leasing program proposed by President Nixon in his energy message to the Congress in 1974,[5] wherein he proposed to lease 10 million acres by 1975—approximately the same acreage leased between 1954 and 1975—the revenue attained from OCS leases could have been significantly larger than the record nominal $6 billion received in 1974. Since that time the Administration has reduced the goal for leasing the OCS to three or four sales in 1976 and six sales per year thereafter with no fixed acreage specified. The Administration's FY 1976 budget originally estimates $8 billion in receipts from OCS activities.[6] These estimates were later reduced to $5 billion.[7] However, the House-Senate Concurrent Budget Resolution estimates offsetting receipts from OCS leases of $2 to $4 billion—one-quarter to one-half of the Administration's estimate.

Although all OCS revenues are credited to miscellaneous receipts, the Land and Water Conservation Fund Act of 1965 authorizes OCS revenues to be "covered over" into the Fund to the extent necessary to complement other funds appropriated by Congress to reach the authorized annual level of $300 million.[8] The Land and Water Conservation Fund authorizes 60 percent of the money to be spent for matching grants to any interior or coastal State for planning, acquisition or development of outdoor recreational lands and waters by the Federal Government. Of the States' share of the Fund, 40 percent is distributed equally among the 50 States, and the remainder is prorated among the States and territories according to an allocation formula based on population and population distribution.

[5] President Richard M. Nixon, The Energy Crisis. Message to the Congress outlining legislative proposals and executive actions to deal with the crisis, January 23, 1974. (H. Doc. 93–201).
[6] Hearings on the Second Budget Resolution, Fiscal Year 1976 Before House Comm. on the Budget, 94th Cong., 1st Sess., a t 35 (1975).
[7] H.R. Rep. No. 94–608, 94th Cong., 1st Session at 43 (1975).
[8] Land and Water Conservation Fund Act of 1965, 16 U.S.C. § 460 1–5(c).

Gravity Platform. The tugs and their 348,000 Dwt reach the narrows of Stavanger (Norway) fjord. The production platform reached its destination in the North Sea Brent field on August 12, 1975.
Courtesy Exxon Corporation.

Since the Fund was established, approximately $1.4 billion has been transferred to the Fund from receipts of OCS leases. This represents more than 62 percent of total contributed to the Fund from all sources over the life of the program; the balance came from sale of surplus property and motorboat fuel taxes. Over $247 million was transferred to the Land and Water Conservation Fund from OCS oil and gas lease sale receipts made in Fiscal Year 1975.[9] The FY 1974 and 1975 contributions comprised 81 and 75 percent of the Land and Water Conservation Fund respectively for those years. OCS revenues contributed significantly to the Federal-State efforts to expand recreational facilities under the Land and Water Conservation Fund Act of 1965.

STATES' SHARE OF MINERAL LEASE PROCEEDS

The Federal Government retains ownership of about 762 million acres or about one-third of the gross land area of the United States. Approximately 74 million acres of these public lands are leased to private operators for the development of mineral resources under the Mineral Leasing Act of 1920.[10] The Act provides for distribution of 37½ percent of the receipts from mineral leases on Federal lands to each State in which the leased land or mineral deposits are located. Expenditures of the money by State or local subdivisions is restricted to the use for construction and maintenance of public roads or for the

[9] U.S. Dept. of the Interior, Bureau of Land Management, News Release, Aug. 17, 1975, 2 pp.
[10] Mineral Leasing Act of 1920, 30 U.S.C. § 181 et seq.

support of public schools and other public educational institutions. Because of the special circumstances of Alaska, where the Federal Government controls 96.7 percent of the land area, the State is awarded 90 percent of the receipts from mineral leases on public lands within the State.

In 1974, $100.6 million was distributed to States under the provisions of the Mineral Leasing Act of 1920. Allocation among the States is shown in Table 10.

TABLE 10.—ALLOCATION OF MINERAL LEASING RECEIPTS AMONG STATES—1974 [1]

State	Mining leases and permits (acres)	Allocation (dollars)
Alabama	48,685	$7,723
Alaska	4,317,312	7,713,508
Arizona	542,349	95,387
Arkansas	275,555	41,234
California	661,454	3,771,468
Colorado	8,503,922	32,502,955
Florida	175,775	2,432
Idaho	1,848,821	510,198
Kansas	60,195	199,246
Louisiana	45,030	236,032
Michigan	88,332	12,612
Mississippi	22,126	11,508
Montana	8,631,798	4,063,105
Nebraska	163,173	28,036
Nevada	1,111,914	317,707
New Mexico	8,536,757	17,977,552
North Dakota	276,256	458,156
Oklahoma	203,109	287,488
Oregon	230,091	35,555
South Dakota	1,204,404	222,340
Utah	14,693,423	5,005,037
Washington	1,878	24,699
Wyoming	22,158,112	27,059,772
Total	73,800,471	100,583,750

[1] Compiled from tables 78 and 117, Bureau of Land Management, Public Land Statistics, 1974.

Revenue from oil and gas leases on the Outer Continental Shelf is not distributed under the Mineral Leasing Act of 1920 because OCS lands are not within the coastal states' boundaries as established by the Submerged Lands Act and the Outer Continetnal Shelf Lands Act. The only access that the coastal states have to OCS revenues is indirectly through the Land and Water Conservation Fund. According to the Bureau of Outdoor Recreation, $795 million has been disbursed from the Fund to the states between Fiscal Years 1969 and 1974, the period during which OCS revenues have been covered over to the Fund.

IMPACT FUNDS FOR COASTAL STATES

The adjacent coastal states note that they are ineligible for receiving distributed funds from revenues of the Outer Continental Shelf as do the interior states from similar Federal activities conducted on public lands within their boundaries; yet there is a consensus among energy and resource planners that OCS development will result in significant environmental, social and economic impacts onshore. In support of compensation to the coastal states, Henry Lee, Director, Massachusetts Energy Policy Office, stated that—

> There should be an equitable share in the Federal royalties and revenues set aside to compensate for all impacted coastal states. With the enactment of the 1920 Mineral Leasing Act, 37½ percent of the Federal revenues derived from resource development on Federal lands within a State's boundaries go directly

to that State, mainly to compensate for the additional public services brought on by that development. . . . Even though Federal OCS lands are not within any coastal State's boundaries, the necessary support service will still emanate from that State * * *. A compensation fund, therefore, should be established to adequately ameliorate these associated economic and environmental impacts * * *. Presently, the coastal States obtain directly none of the revenues derived from the OCS leasing program, yet they must bear substantial impact costs.[11]

Initiating offshore oil and gas development in the OCS adjacent to the frontier states presents a unique problem for coastal planning. Without the infrastructure and processing facilities in place, as they were in the Gulf Region and in Southern California where onshore oil development preceded offshore drilling, frontier states on the East Coast must accommodate oil-related facilities in coastal zones. In Alaska, development will occur on virgin coastlines in regions where societal impacts as well as environmental impacts may be severe. To minimize the adverse impacts from OCS development in these regions, planning and proper pacing of development is seen as critical. This need was amplified by Dr. William J. Hargis, Jr., Chairman, National Advisory Committee on Oceans and Atmosphere, and Director, Virginia Institute of Marine Sciences:

There is no doubt that coastal States which are expected to be involved in OCS activities will need "front-end" money to plan for anticipated onshore impacts of offshore development. Rather comprehensive planning efforts will be required to properly integrate the onshore activity induced by the OCS development into both the local, and in many cases, the regional economy. Such will be necessary to provide balanced service and industrial facilities in a way that minimizes pollution levels and "other-use" conflicts.[12]

The Coastal Zone Management Act of 1972 is considered to be the primary device for coastal states to institute the comprehensive planning necessary to minimize the impact of offshore development. The Chairman of the Council on Environmental Quality, Russell W. Peterson, noted that:

* * * there is no better preparation for the effects of OCS development activities than the kind of planning, institutional reform, and development of regulatory mechanisms already underway by the States under the Coastal Zone Management Act of 1972 * * *. Whatever the need for Federal money to help offset the effects of OCS development, a more fundamental need is to encourage continued progress toward strong coastal zone management laws and programs in every coastal State.[13]

While the Coastal Zone Management Act is almost three years into implementation and all of the potentially impacted coastal states are participating in the Sec. 305 program, Robert W. Knecht, Assistant Administrator, Office of Coastal Zone Management, NOAA, noted that:

* * * the energy crisis is national in scope, even international, and thus requires some kind of national response by Congress. However, this body evidenced its concern about the protection of the Nation's coastal areas when it passed the Coastal Zone Management Act of 1972: thus, one question with which the [Merchant Marine and Fisheries] committee is wrestling is whether the Coastal Zone Management Act needs modification in view of our needs for offshore energy.[14]

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[11] Hearings on H.R. 3981 and S. 586 et al. Before the Subcommittee on Oceanography of the House Committee on Merchant Marine and Fisheries, 94th Cong., 1st Sess., ser. 94-11, at 88-89 (1975).

[12] Id. at 102-103.

[13] Id. at 174.

[14] Id. at 43.

A number of legislative proposals introduced in the 94th Congress would provide additional money for accelerating the State's efforts under Sec. 305 in devising a State coastal zone management program. Other proposals would require the States to implement an energy facility planning process as part of the overall coastal zone management program. While the present Coastal Zone Management Act clearly includes energy facilities in the comprehensive management approach, some insist that more emphasis must be given to the energy component of the coastal zone programs and that additional resources should be provided to accelerate the development of the State coastal zone management programs.

It is acknowledged, however, that planning can not overcome all the impacts which may result from OCS oil and gas development. Where new public facilities and additional public services are required, front-end investment capital is needed at the local and state levels to underwrite the initial investment. Such public investment must come prior to the construction of facilities and will often precede by several years the assessment and enrollment of physical structures on the tax rolls. Thus fiscal remedies are needed by the states, according to proponents of state OCS compensation, to finance community services needed to advance the national interest in prompt development of the OCS.

While there appears to be little opposition to redistribution of some Federal revenues from OCS oil and gas leasing, there is broad disagreement on the amount to be transferred to State and local governments, the manner in which it is distributed and the purposes for which it may be used. Seventeen bills were introduced during the first session of the 94th Congress to provide for distribution of Federal OCS revenues to the States. The bills propose a variety of approaches for allocating and distributing OCS revenues to the coastal States, the elements of which are outlined in Table 11.

TABLE 11.—ELEMENTS AND PROCEDURES FOR DISTRIBUTING OCS REVENUES TO STATE AND LOCAL GOVERNMENTS

Allocation from Federal Treasury	Distribution to State and local governments	Uses by State and local governments
A. Appropriation	1. Percentage of revenues	a. All coastal energy facilities
B. Earmarking	2. Per barrel severance rate	b. OCS-related facilities only.
	3. Formula	c. Loans.
	4. Adverse impacts	d. Bond guarantees.
	5. Net adverse impacts	

APPROPRIATION OF FUNDS

The power to allocate revenues and expenditures from the Federal Treasury through appropriations is granted to the Congress by Article I, Section 9 of the United States Constitution. Congress may, if it so chooses, appropriate money on a continuing or permanent basis. Normally, however, funds are authorized and appropriated on an annual or short-term renewable basis.

It has been suggested by some that a portion of Federal OCS revenues be earmarked for distribution to the States at a continuing, predetermined rate. In effect, this would constitute a permanent or indefinite appropriation for the period of authorization. Opponents of permanent appropriations allege that such procedures result in uncertainty in determining the total funds voted for supporting governmental functions, and impairs the powers of Congress in directing and controlling spending. Program review, which normally accompanies the annual appropriation process, is foregone since permanent appropriations require no further action by the Congress. Historically, Congress has not favored permanent appropriations, and in 1934 abolished 367 such appropriations by the Permanent Appropriations Repeal Act.[15] The notable exceptions, however, are the national debt service charges and appropriations for State-aid for agricultural extension work, land grant colleges and agricultural vocational education, which are still handled through indefinite appropriations.

Those who favor earmarking funds for revenue sharing with the States cite the need for localities and coastal States to be assured of continued funding for long-term investments to ameliorate the impact of OCS development. Earmarking of funds in proportion to offshore production of oil and gas is seen as a mechanism to assure an equitable flow of impact money to the adjacent States without the necessity of coming to the Congress annually "with hat in hand."

DISTRIBUTION OF FUNDS AMONG STATES

A major criterion for any compensation scheme is equitable distribution among the impacted coastal States. Several approaches have been suggested: (1) percentage shares of revenues produced offshore; (2) per-barrel fixed or sliding rate for each barrel of oil or gas equivalent produced offshore; (3) formula distribution based on criteria such as number of wells drilled, barrels of oil produced and persons employed in the offshore industry, etc.; (4) compensation based on "net adverse impacts" suffered, i.e., costs minus benefits from OCS activities; and (5) compensation for impacts suffered ignoring any benefits which may accrue.

Revenue sharing based upon a percentage allocation of the OCS revenues removed offshore of the respective State is analagous to the approach of the Mineral Leasing Act of 1920. A system based upon a per-barrel severance rate would differ from a percentage revenue share only in the relationship of the rate set and method of computation. In all other ways, these two systems are identical.

Formula distribution has been used to allocate funds among the States for a number of Federal programs.[16] Proponents of formula distribution consider its strength to be in the certainty and objectivity of the calculus, assuming of course, that the formula bears a proportional relationship to the purpose of the grant. Simplicity of administration is also considered to be an attribute of the formula system. Opponents allege however, that formula allocation seldom accurately apportions the money because the factors chosen for quantification are usually facile and bear little relationship to the purpose of the grant. Frequently, population, area or number of determinable units are used in the formula and this, according to its detractors, permits

[15] Galloway, The Legislative Process in Congress 126 (1953).

[16] For a compilation of Federal programs of grant-in-aid to State and local governments and the method of allocation See: Senate Committee on Government Operations, Federal Programs of Grants-in-Aid to State and Local Governments, 91st Congress, 1st Sess. (1969).

the administrator to blindly distribute funds without further analysis or evaluation of equity. Supporters of the grant approach consider this to be a strength rather than a weakness and claim that formula distribution prevents capricious or arbitrary decisions by an administrator in apportioning finite funds among competing States.

Distribution for adverse impacts or "net" adverse impacts are based on a concept of demonstrated need. The two approaches differ to the extent that the latter considers the balance between the benefits which accrue to a region as a result of offshore oil and gas development and the negative impacts which may result. The rationale for the net adverse impact approach has been explained on the basis that—

> * * * impact grants will be made only when a State can demonstrate that an energy facility or energy resource development can be expected to produce a net balance of adverse impacts over the course of its operational lifetime. Demonstration of net adverse impacts is required in recognition of the fact that such a facility or development generally can be expected to produce positive benefits, such as increased tax revenues and assessed property vaules from land use changes and population increases, as well as negative effects, such as environmental damage or increased demands on public facilities and services. The purpose * * * is to offset any net amount by which the expected or actual costs exceed the expected or actual benefits.[17]

Opponents of the impact approach cite the difficulty inherent in a distribution system which involves subjective judgment and must rely on many "unquantifiable" variables to determine the size of grant to a qualifying State. Those who oppose adverse impact distribution are further concerned that the system will ultimately result in subjective determinations by the administrator and/or complex regulations which will consume energy, money and time which could better be spent for other projects on the State agenda. Supporters of the net adverse impact approach deny this and assert that methodologies can be developed on a timely basis for making "objective" determinations of the net impacts and that the cost of administration will be no more burdensome than by a formula approach. The closest analogy of the impact appoach which presently exists in Federal grant programs is the "project" concept of awarding grants. Project grants are normally awarded on the basis of need as demonstrated by a proposal or project description based on guidelines or regulations established by the administrator. In effect, adverse impact grants would operate similarly by requiring an assessment of net adverse impacts to be made by the States, and documented and submitted to the administrator for review and approval.

USES OF IMPACT GRANTS

Controversy has arisen from proposals that grants be provided to the coastal States for any impact which results from the siting of any "energy facility" in the coastal zone whether OCS-related or not. The rationale for compensating all energy facilities is based upon the uniqueness of the coastal region where cooling water, resources and load centers all merge at the coastal margin. Proponents of the comprehensive approach to coastal energy facility siting and impact compensation claim that energy facilities will inextricably be attracted to the coastal region, that national interest demands that the coastal

[17] S. Rept. No. 94-277, Senate Committee on Commerce, Coastal Zone Management Act Amendments of 1975 23, 94th Cong., 1st. Sess. (1975).

zone absorb more than its proportionate share of the impact burden and therefore the coastal States are entitled to compensation for impacts resulting from activities that primarily benefit persons beyond the coastal region. Opponents allege that compensation for non-OCS-related energy activities will serve as an incentive for coastal States to site facilities in the coastal zone and therefore will be counterproductive to the goals of the Coastal Zone Management Act which was intended to protect the coastal environment. This conclusion is based upon the assumption that many energy facilities such as central power generating stations, oil refineries and processing facilities can be sited outside the coastal zone, and that given this option States will choose to place them in the coastal zone to take advantage of compensation reimbursements. Supporters dismiss this argument as a false issue and claim that such alternative siting options seldom exist and allege that energy facility siting decisions are based on economics and physical proximity to the necessary resources and these attributes are found predominantly in the coastal zone.

Proposals have been made to provide impacted States with long-term Federal loans for front-end investments in coastal regions where initial adverse impacts may result from offshore oil and gas development, but where it is anticipated that positive benefits will outweigh negative impacts over the long-term. In such cases, it is suggested, that what is needed is investment capital to provide services and infrastructure immediately but that increased tax base and depreciation will ultimately recover and service the debt over time. However, in some States the legislature is prohibited by the State constitution from fiscally binding future legislatures to public debts through loans. To that extent the effectiveness of such a loan provision may be limited.

Bond guarantees have been suggested as another means for offsetting front-end investments at the local and State levels. Sale of municipal bonds has suffered somewhat with the near forfeiture of New York City on its bonded indebtedness, therefore bond guarantees may be welcome by State and local governments as an alternative means of financing initial public investments.

Expenditures of impact grants are generally restricted in the legislative proposals to use for ameliorating or avoiding environmental, social and economic impacts or for providing appropriate service and infrastructure required as a result of offshore activity. This is not the case in every instance however, and some proposals have no restrictions on location or type of use, and therefore may be considered no-strings revenue sharing in effect.

APPENDIX I. GLOSSARY OF GEOLOGICAL TERMS[1]

Anticline: A convex upward fold of rock strata, the core of which contains the older rocks.

Cenozoic Era: The era of geologic time between 65 million years ago and the present. The age of mammals. The Cenozoic is divided into the Tertiary period (including the Paleocene, Eocene, Oligocene, Miocene, and Pliocene epochs) and the Quaternary period (including the Pleistocene and Recent epochs).

Clastic: Sediments formed by the accumulation of fragments derived from preexisting rocks and transported to their place of deposition by mechanical agents such as water, wind, ice, gravity, etc. e.g. gravel, sand, mud, clay.

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[1] Source: Adapted from Gary, Margaret; McAfee, Robert; and Wolf, Carol L.: *Glossary of Geology*. American Geological Institute, Washington, D.C., 1972, 857 pages.

Continental Margin: The ocean floor that lies between the shoreline and the deep abyssal ocean floor, and includes the continental shelf, the continental slope, and the continental rise.

Continental Rise: That part of the continental margin between the continental slope and the abyssal plain. It has a gentle incline with slopes of 1:40 to 1:2000 and generally smooth topography although it may contain submarine canyons.

Continental Shelf: That part of the continental margin that is between the shoreline and the continental slope. It is characterized by a very gentle slope of around 0.1 degree.

Continental Slope: That part of the continental margin that lies between the continental shelf and the continental rise. It is characterized by its relatively steep slope of about three to six degrees.

Core (Earth): The central zone of the Earth's interior below a depth of 2,900 kilometers. Only compression seismic waves transverse the core and the earth's magnetic field originates within the core.

Crust (Earth): The outermost layer or shell of the Earth representing less than 0.1 of the Earth's volume.

Diabase: An intrusive crystalline igneous rock whose main minerals are labradorite and pyroxene.

Diapir: A dome or anticlinal fold, the convex overlying layers of which have been ruptured by the squeezing out of the plastic core material. Diapirs in sedimentary strata usually contain cores of salt or shale.

Evaporite: A sedimentary rock composed primarily of minerals formed from the evaporation of saline waters, e.g. a deposit of salt precipitated by the evaporation of an enclosed body of seawater or a salt lake.

Facies change: a lateral or vertical variation in sediment composition and type or kinds of contained fossils. It is caused by, or reflects, a change in depositional environment.

Fault: A rock fracture along which movement (displacement) has taken place

Gabbro: A dark colored, crystalline igneous rock composed principally of basic plagioclase and clinopyroxene minerals.

Geologic basin: A general term for a large, depressed, sediment filled area.

Geosyncline: A large, mobile downwarped area of the Earth's crust, either elongate or basinlike, which is subsiding as sedimentary rocks accumulate to thicknesses of thousands of meters.

Igneous Rock: A rock that solidified from molten or partly molten material (magma or lava).

Lithology: The description of rocks on the basis of such characteristics as color, structure, minerals, and grain size, e.g. the physical character of a rock.

Mafic Rock: An igneous rock composed chiefly of one or more of the ferromagnesian minerals.

Mantle (Earth): The zone of the Earth below the crust and above the core.

Mesozoic Era: The era of geologic time between 225 and 65 million years ago. The time of the age of reptiles. The Mesozoic is divided into the Triassic, Jurassic, and Cretaceous periods.

Paleozoic Era: The era of geologic time between 225 and 570 million years ago. The time of the rise of the invertebrates and the fishes. The Paleozoic is divided into the Cambrian, Ordovician, Silurian, Devonian, Mississippian, Pennsylvanian, and Permian periods.

Peridotite: A coarse-grained igneous rock composed chiefly of the mineral olivine.

Physiography: The study of the description and origin of landforms.

Precambrian: The era of geologic time between the formation of the Earth's crust about 4,600 million years ago and the beginning of the Paleozoic era 570 million years ago.

Sialic Rock: A rock rich in silica and alumnia.

Stratigraphic Trap: The sealing of a hydrocarbon reservoir bed as the result of a lithologic change (a change in the physical character of the rock) rather than through structural trapping.

Stratigraphy: The arrangement of strata, especially in regards to geographic position and chronologic order of sequence. It also involves the interpretation of the characters, properties, and attributes which the rock strata may possess.

Structural Trap: The containment of oil or gas within a reservoir bed as the result of a flexure or fracture of the rock strata.

Tectonics: The broad architecture of the rocks of the upper part of the Earth's crust. The study of the regional structural and deformational features of the crust and their relations, origin, and evolution.

Terrestrial Sediment: A sedimentary deposit laid down on land.

Unconformity: A substantial break or gap in the geologic record where a rock unit is overlain by another that is not next in stragigraphic succession. It results from a change that caused deposition to cease for a considerable span of time and normally implies uplift and erosion with loss of previously deposited strata.

Wedgeout: The edge or line of pinch-out of a lensing or truncated rock formation. Wedgeouts can form stratigraphic traps.

APPENDIX II

OIL AND GAS OPERATIONS, OUTER CONTINENTAL SHELF

LOUISIANA

Calendar year	Oil			Condensate		
	Quantity (barrels)	Production value	Royalty value	Quantity (barrels)	Production value	Royalty value
1953	940,634	$2,770,866	$584,088	210,063	$719,664	$135,453
1954	2,723,173	8,028,326	1,681,702	619,057	1,947,804	361,496
1955	5,869,897	17,312,409	3,538,967	833,631	2,624,334	483,418
1956	10,123,071	29,724,365	6,013,072	878,177	2,738,187	505,938
1957	15,367,279	51,146,960	9,790,301	697,116	2,397,306	432,270
1958	23,709,108	77,266,710	14,482,598	1,059,929	3,470,484	627,780
1959	34,177,272	108,196,671	20,331,582	1,519,992	4,871,845	889,736
1960	47,359,046	139,113,688	27,843,078	2,306,845	7,320,399	1,328,526
1961	61,265,770	192,144,960	35,462,210	3,064,308	9,527,903	1,788,043
1962	84,928,426	264,041,875	48,705,620	4,804,673	14,874,907	2,799,353
1963	98,278,494	313,637,681	55,591,619	6,247,942	19,168,310	3,618,838
1964	114,972,300	352,663,296	64,358,443	7,522,873	22,941,499	4,236,902
1965	136,232,315	417,131,468	75,417,796	8,732,553	26,664,321	4,988,612
1966	174,304,792	535,253,645	95,584,085	13,526,680	41,750,232	7,679,495
1967	204,698,134	630,364,403	112,166,314	14,297,694	42,884,947	7,743,531
1968	248,223,799	769,355,722	136,455,284	15,601,560	50,711,986	9,046,994
1969	283,974,318	925,153,657	162,162,256	16,184,974	56,381,108	9,863,476
1970	311,035,150	1,036,032,944	180,410,505	22,376,342	77,309,709	13,291,113
1971	358,366,080	1,277,637,359	218,947,766	27,394,271	99,350,[illegible]3	16,835,804
1972	355,029,953	1,257,524,468	214,844,499	32,560,709	119,704,749	20,060,994
1973	341,277,611	1,413,819,684	237,227,064	32,919,254	136,308,235	22,505,037
1974	315,124,798	2,116,320,829	348,152,189	27,310,698	194,647,283	31,596,951
Total	3,227,981,420	11,934,641,986	2,069,751,138	240,669,332	938,314,965	160,869,750

Source: U.S. Geological Survey, June 1975. Harris, Walter M., Piper Sharon K., McFarlane, Bruce E, "Outer Continental Shelf Statistics."

APPENDIX III

Louisiana

Calendar year	Oil and condensate			Gas		
	Quantity (barrels)	Production value	Royalty value	Quantity (million cubic feet)	Production value	Royalty value
1953	1,150,697	$3,490,530	$719,541	19,881,055	$1,546,331	$248,351
1954	3,342,230	9,976,130	2,043,198	56,325,083	4,393,698	705,779
1955	6,703,528	19,936,743	4,022,385	81,279,042	7,118,031	1,116,642
1956	11,001,248	32,462,552	6,519,010	82,892,538	6,995,060	1,103,693
1957	16,064,395	53,544,266	10,222,571	82,568,807	7,507,953	1,165,294
1958	24,769,037	80,737,194	15,110,378	127,692,848	15,733,942	2,313,500
1959	35,697,264	113,068,516	21,221,318	207,156,296	37,403,164	5,318,518
1960	49,665,891	146,434,087	29,171,604	273,034,451	52,751,614	7,636,074
1961	64,330,078	201,672,863	37,250,253	318,280,095	64,615,520	9,483,489
1962	89,733,099	278,916,782	51,504,973	451,952,659	2,209,196	13,748,400
1963	104,526,436	332,805,991	59,210,457	564,352,606	106,783,758	16,136,781
1964	122,495,173	375,604,795	68,645,345	621,731,438	118,377,080	17,887,512
1965	144,964,868	443,795,789	80,406,508	645,589,469	126,977,562	19,248,110
1966	187,831,472	577,006,877	103,263,580	965,387,849	182,465,908	27,989,727
1967	218,995,828	673,249,350	119,909,845	1,087,262,804	210,606,727	29,186,187
1968	263,825,359	820,067,708	145,502,268	1,413,467,606	272,969,079	45,405,714
1969	300,159,292	981,534,765	172,025,732	1,822,544,142	344,015,027	53,764,395
1970	333,411,492	1,113,342,153	193,701,618	2,273,147,040	414,018,458	65,425,568
1971	385,760,351	1,376,987,612	235,783,570	2,634,014,031	525,451,277	83,373,079
1972	387,590,662	1,377,229,217	234,905,493	2,881,364,733	636,164,978	102,311,962
1973	374,196,856	1,550,127,919	259,732,101	3,006,628,236	707,142,624	113,289,175
1974	342,435,496	2,310,968,112	379,749,140	3,349,170,864	844,519,248	136,123,741
Total	3,468,650,752	12,872,956,951	2,230,620,888	23,01[illegible]723,692	4,779,776,505	751,981,698

Source: U.S. Geological Survey, op. cit.

APPENDIX IV
Louisiana

Calendar year	Gasoline and LPG: Quantity (gallons)	Gasoline and LPG: Production value	Gasoline and LPG: Royalty value	Sulfur: Quantity (tons)	Sulfur: Production value	Sulfur: Royalty value
1960				98,025	$1,762,866	$285,784
1961				401,521	7,252,931	1,170,733
1962				285,975	5,507,050	835,816
1963				552,573	11,069,637	1,617,471
1964				634,875	12,748,602	1,858,535
1965				1,080,950	23,387,005	3,197,532
1966				1,400,848	32,621,551	4,128,691
1967				1,409,276	37,291,107	4,167,804
1968				1,553,621	53,277,667	4,628,512
1969	222,430,316	$9,777,811	$714,111	1,232,939	49,129,573	3,684,432
1970	1,027,998,797	49,247,030	3,582,647	1,099,584	24,636,736	3,235,874
1971	1,462,879,363	76,751,561	5,659,170	1,178,400	23,718,311	3,452,117
1972	1,654,668,547	85,637,383	6,258,847	1,176,833	22,286,906	3,438,515
1973	1,557,169,529	101,743,599	7,487,901	1,235,358	23,748,632	3,610,757
1974	1,959,936,667	249,229,701	19,359,315	1,303,750	34,820,443	3,852,700
Total	7,885,083,219	572,387,085	43,061,991	14,654,528	363,259,017	43,165,273

Source: U.S. Geological Survey.

APPENDIX V
Louisiana

Calendar year	Salt: Quantity (tons)	Salt: Production value	Salt: Royalty value	Oil lost: Quantity	Oil lost: Production value	Oil lost: Royalty value
1960	59,794	$10,764	$1,792			
1961	528,581	95,142	15,857			
1962	176,924	31,848	5,308			
1963	262,951	47,334	7,889			
1964	212,978	38,334	6,389			
1965	290,804	52,334	8,724			
1966	297,475	53,544	8,924			
1967	274,422	49,396	7,422			
1968	540,651	97,317	17,030			
1969	343,060	61,751	10,292			
1970	269,691	48,544	8,091			
1971	370,406	66,673	11,112			
1972	358,782	64,581	10,764			
1973	381,247	68,624	11,437			
1974	346,411	62,354	10,392	2,772	$15,717	$2,708
Total	4,714,177	848,540	141,423	2,772	15,717	2,708

Source: U.S. Geological Survey, op. cit.

APPENDIX VI
Louisiana

Calendar year	Gas lost: Quantity (million cubic feet)	Gas lost: Production value	Gas lost: Royalty value	Total all products: Production value	Total all products: Royalty value
1953				$5,036,861	$967,892
1954				14,370,098	2,748,977
1955				27,054,774	5,139,027
1956				39,457,612	7,622,708
1957				61,052,219	11,387,865
1958				96,471,136	17,423,878
1959				150,471,680	26,539,836
1960				200,969,331	37,095,254
1961				273,636,456	47,920,332
1962				376,654,876	66,094,497
1963				450,706,720	76,972,598
1964				506,768,811	88,367,781
1965				594,212,680	102,860,874
1966				792,144,889	135,390,922
1967				921,196,580	153,271,258
1968				1,146,411,771	195,553,524
1969				1,384,518,927	230,198,962
1970				1,601,292,921	265,953,798
1971				2,002,975,434	328,279,048
1972				2,121,383,065	345,925,581
1973				2,382,831,398	384,131,371
1974	14,523,498	$3,923,102	$601,125	3,443,538,577	539,609,121
Total	14,523,498	3,923,102	601,125	18,583,166,917	3,088,575,104

Source: U.S. Geological Survey, op. cit.

APPENDIX VII

TEXAS

Calendar year	Oil: Quantity (barrels)	Oil: Production value	Oil: Royalty value	Condensate: Quantity (barrels)	Condensate: Production value	Condensate: Royalty value
1955	1,956	$5,905	$979			
1956	13,284	40,259	6,675			
1957	5,792	19,889	3,296			
1958						
1959	257	847	141			
1960	98	284	47			
1961						
1962	3,483	11,024	1,837			
1963	52,804	159,764	26,627			
1964	4,953	14,699	2,449			
1965	3,747	10,042	1,666			
1966	882,598	2,664,147	444,017			
1967	1,162,401	3,625,423	604,236	1,703,385	$5,305,062	$884,177
1968	1,732,657	5,535,456	922,577	1,377,985	4,454,244	742,372
1969	1,514,315	5,191,533	865,045	1,245,536	4,361,621	726,926
1970	1,100,107	3,856,600	642,715	1,146,941	4,098,461	683,077
1971	710,453	2,610,888	431,713	974,584	3,674,607	612,435
1972	905,023	3,407,703	563,322	827,995	3,197,222	532,081
1973	605,850	2,717,407	449,665	921,970	4,411,721	729,876
1974	452,613	2,487,210	411,732	929,212	7,307,134	1,201,746
Total	9,242,410	32,359,060	5,378,739	9,127,608	36,810,072	6,112,000

Source: U.S. Geological Surevy, op. cit.

APPENDIX VIII

Texas

Calendar year	Oil and condensate: Quantity (barrels)	Oil and condensate: Production value	Oil and condensate: Royalty value	Gas: Quantity (million cubic feet)	Gas: Production value	Gas: Royalty value
1955	1,956	$5,905	$979			
1956	13,284	40,259	6,675			
1957	5,792	19,889	3,296	4,797	$480	$84
1958						
1959	257	847	141			
1960	98	284	47			
1961						
1962	3,483	11,024	1,837			
1963	52,804	159,764	26,627			
1964	4,953	14,699	2,449			
1965	3,747	10,042	1,666			
1966	882,598	2,664,147	444,017	42,059,306	6,915,584	1,152,598
1967	2,865,786	8,930,485	1,488,413	99,952,946	17,087,626	2,847,938
1968	3,110,642	9,989,700	1,664,949	109,910,787	18,073,163	3,012,028
1969	2,759,851	9,553,154	1,591,971	127,006,982	20,447,082	3,407,848
1970	2,247,048	7,955,061	1,325,792	133,300,404	20,816,080	3,469,347
1971	1,685,047	6,285,475	1,044,148	127,357,908	19,965,436	3,327,573
1972	1,733,018	6,604,925	1,085,403	147,156,459	24,773,734	4,128,957
1973	1,617,829	7,129,128	1,179,541	148,673,637	27,766,325	4,627,604
1974	1,381,825	9,794,344	1,613,478	159,979,401	31,695,920	5,282,655
Total	18,370,018	68,169,132	11,491,429	1,095,492,707	187,540,430	31,256,722

Source: U.S. Geological Survey, op. cit.

APPENDIX IX

Texas

Calendar year	Gasoline and LPG: Quantity (gallons)	Gasoline and LPG: Production value	Gasoline and LPG: Royalty value	Oil lost: Quantity (gallons)	Oil lost: Production value	Oil lost: Royalty value
1970	47,255,294	$1,925,020	$145,721			
1971	85,672,796	3,679,883	276,415			
1972	82,440,797	3,570,724	265,883			
1973	77,638,868	3,604,861	280,180			
1974	71,606,533	5,514,277	437,017	132	$680	$87
Total	364,613,288	18,383,965	1,405,216	132	680	87

Source: U.S. Geological Survey, op. cit.

APPENDIX X

TEXAS

Calendar year	Gas lost: Quantity (million cubic feet)	Gas lost: Production value	Gas lost: Royalty value	Total all products: Production value	Total all products: Royal value
1955				$5,905	$976
1956				40,259	6,675
1957				20,369	3,380
1958					
1959				847	141
1960				284	47
1961					
1962				11,024	1,837
1963				159,764	26,627
1964				14,699	2,449
1965				10,042	1,666
1966				9,579,731	1,596,615
1967				26,018,111	4,336,351
1968				28,061,863	4,676,977
1969				30,000,236	4,999,819
1970				30,696,161	4,940,860
1971				29,930,804	4,648,136
1972				34,949,383	5,490,243
1973				38,389,504	6,087,415
1974	45,270	$10,422	$1,590	47,015,652	7,334,827
Total	45,270	10,422	1,590	275,104,638	44,155,044

Source: U.S. Geological Survey.

APPENDIX XI

TOTAL OFFSHORE OIL AND GAS PRODUCTION

OIL AND CONDENSATE
TOTAL OFFSHORE "STATE" AND "FEDERAL OCS"

[In thousands of barrels]

	Louisiana			Texas		
		Percent			Percent	
	Barrels	State	OCS	Barrels	State	OCS
Prior	54,803	98	2			
1954	15,926	79	21	10	100	......
1955	25,731	74	26	156	99	1
1956	40,906	73	27	140	90	10
1957	52,835	70	30	256	98	2
1958	57,381	57	43	470	100	......
1959	72,793	51	49	499	100	......
1960	88,122	44	56	567	100	......
1961	103,197	38	62	292	100	......
1962	126,801	29	71	803	100	......
1963	148,087	30	70	660	92	8
1964	173,700	29	71	578	99	1
1965	198,283	27	73	557	99	1
1966	243,000	23	77	1,246	29	71
1967	284,033	23	77	3,400	16	84
1968	328,922	20	80	3,400	9	91
1969	365,601	18	82	3,100	11	89
1970	388,378	16	84	3,046	26	74
1971	444,363	13	87	2,885	42	58
1972	452,584	14	86	3,035	43	57
1973	428,466	13	82	2,285	29	71
1974	388,260	12	88	1,860	26	74
Total	4,487,360	23	77	29,272	37	63

GAS
TOTAL OFFSHORE "STATE" AND "FEDERAL OCS"

[In millions of cubic feet]

	Louisiana			Texas		
		Percent			Percent	
	MM cf	State	OCS	MM cf	State	OCS
Prior	91,675	78	22			
1954	81,325	31	69	3,440	100	......
1955	121,279	33	67	6,800	100	......
1956	136,527	39	61	6,800	100	......
1957	160,472	.49	51	13,765	100	......
1958	233,967	45	55	24,000	100	......
1959	329,200	37	63	24,000	100	......
1960	408,388	33	67	30,950	100	......
1961	458,481	31	69	13,760	100	......
1962	588,361	23	77	41,290	100	......
1963	706,545	20	80	30,940	100	......
1964	783,474	21	79	30,960	100	......
1965	871,124	26	74	27,520	100	......
1966	1,265,800	24	76	58,259	29	71
1967	1,655,223	34	66	127,473	22	78
1968	2,057,291	31	69	154,631	29	71
1969	2,478,745	26	74	240,212	47	53
1970	2,800,104	19	81	264,420	50	50
1971	3,219,200	18	82	387,245	67	33
1972	3,480,831	17	83	156,772	6	94
1973	3,614,882	15	85	250,338	41	59
1974	3,871,964	14	86	250,338	37	63
Total	29,415,047	22	78	2,148,253	49	51

Source: U.S. Geological Survey, op. cit.

APPENDIX XII

(See figure 11, page 99, for Appendix XII.)

APPENDIX XIII

REGULATIONS PERTAINING TO MINERAL LEASING ON THE OUTER CONTINENTAL SHELF AS CONTAINED IN TITLE 43 OF THE CODE OF FEDERAL REGULATIONS

GROUP 3300—OUTER CONTINENTAL SHELF LEASING

PART 3300—OUTER CONTINENTAL SHELF LEASING; GENERAL

SUBPART 3300—OUTER CONTINENTAL SHELF MINERAL DEPOSITS; GENERAL

Sec.
3300.0–3 Purpose and authority.
3300.0–4 Applicability of public lands laws.
3300.1 Persons qualified to hold leases.
3300.3 Helium.
3300.4 Payments of filing charges, bonuses, rentals and royalties.

SUBPART 3301—LEASING AREAS

3301.1 Leasing maps.
3301.2 Resources evaluation.
3301.3 Nominations of tracts.
3301.4 Selection of tracts.
3301.5 Notice of lease offer.
3301.6 Tracts subject to drainage.

SUBPART 3302—ISSUANCE OF LEASES

3302.1 General.
3302.2 Term.
3302.4 What must accompany any bids.
3302.5 Award of lease.
3302.6 Form.
3302.7 Dating of leases.

SUBPART 3303—RENTALS AND ROYALTIES

3303.1 Rentals.
3303.2 Royalties.
3303.3 Minimum royalty.
3303.5 Effect of suspensions on royalty and rental.

SUBPART 3304—BONDS

3304.1 Amount of bond required of lessee.
3304.2 Form of bond.

SUBPART 3305—ASSIGNMENTS OR TRANSFERS

3305.1 Assignment of leases or interests therein.
3305.2 Requirements for filing of transfers.
3305.3 Separate assignments required for transfer of record title to leases.
3305.4 Effect of assignment of particular tract.

SUBPART 3305A—EXTENSION OF LEASES

3305a.1 Extension of leases by drilling or well reworking operations.
3305a.2 Directional drilling.
3305a.3 Compensatory payments.
3305a.4 Effect of suspension on lease term.

SUBPART 3306—TERMINATION OF LEASES

3306.1 Relinquishment of leases or parts of leases.
3306.2 Cancellation of leases.

SUBPART 3307—MINERAL DEPOSITS AFFECTED BY SECTION 6 OF OUTER CONTINENTAL SHELF LANDS ACT

3307.1 Effect of regulations on provisions of lease.
3307.2 Leases of other minerals.
3307.3 Obligations of lessee.
3307.3–1 Bonds.
3307.3–2 Wells.
3307.3–3 Inspection.
3307.3–4 Diligence; compliance with regulations and orders.
3307.3–5 Freedom of purchase.
3307.3–6 Removal of property on termination of lease.
3307.4 Exploration and operations.
3307.4–1 Purchase of production.
3307.4–2 Suspension of operations during war or national emergency.
3307.4–3 Restriction of exploration and operations.
3307.4–4 Geological and geophysical exploration; rights-of-way.
3307.4–5 Leases of sulphur and other mineral.
3307.5 Remedies in case of default.
3307.6 Heirs and successors in interest.

SUBPART 3300—OUTER CONTINENTAL SHELF MINERAL DEPOSITS; GENERAL

§ 3300.0-3 Purpose and authority.

The Outer Continental Shelf Lands Act of August 7, 1953 (67 Stat. 462; 43 U.S.C. § 1331 et seq.), referred to in this part as "the act," among other things, authorizes the Secretary of the Interior to issue on a competitive basis leases for oil and gas, sulphur, and other minerals in submerged lands of the Outer Continental Shelf, as defined in section 2 of the act. Subject to the supervisory authority of the Secretary, the regulations in this part shall be administered by the Director, Bureau of Land Management, hereinafter referred to in this part as the Director.

§ 3300.0-4 Applicability of public land laws.

The laws and regulations pertaining to the public lands of the United States are not applicable to the submerged lands of the Outer Continental Shelf. Mineral deposits in the submerged lands of the Outer Continental Shelf are subject to disposition only in accordance with the provisions of the act and the regulations promulgated by the Secretary thereunder.

§ 3300.1 Persons qualified to hold leases.

Mineral leases issued pursuant to section 8 of the act may be held only by citizens of the United States over 21 years of age, associations of such citizens, States, political subdivisions of a State, or private, public, or municipal corporations organized under the laws of the United States or of any State or Territory thereof.

§ 3300.3 Helium.

Each lease issued or continued under the act shall be subject to a reservation by the United States of the ownership of and the right to extract helium from all gas produced from the leased area, subject to such rules and regulations as shall be prescribed by the Secretary of the Interior. In case the United States elects to take the helium, the lessee shall deliver all gas containing helium, or the portion of gas desired, to the United States at any point on the leased area in the manner required by the United States, for the extraction of helium in such plant or reduction works for that purpose as the United States may provide, whereupon the residue shall be returned to the lessee with no substantial delay in the delivery of gas produced from the well to the purchaser thereof. The lessee shall not suffer a diminution of value of the gas from which the helium has been extracted, or loss otherwise, for which he is not reasonably compensated, save for the value of the helium extracted. The United States shall have the right to erect, maintain, and operate on the leased area any and all reduction works and other equipment necessary for the extraction of helium.

§ 3300.4 Payments of filing charges, bonuses, rentals and royalties.

All payments to the United States required by the act or the regulations in this part shall be made to the oil and gas supervisor of the Geological Survey for the region in which the leased area is situated, except that payments of filing charges, bonuses and first year's rental shall be made to the manager of the appropriate field office, Bureau of Land Management, unless otherwise directed by the Secretary. All payments should be made by check, bank draft, or money order payable to the United States Geological Survey, if the payments are made to the Geological Survey, or to the Bureau of Land Management, if the payments are made to that Bureau.

Subpart 3301—Leasing Areas

§ 3301.1 Leasing maps.

(a) Any area of the Outer Continental Shelf which has been appropriately platted as provided in paragraph (b) of this section is subject to lease for any mineral not included in a subsisting lease issued under the act or meeting the requirements of subsection (a) of section 6 of the act, unless before any lease is offered or issued the unit is (1) withdrawn from disposition pursuant to section 12(a) of the act, or (2) designated as an area or part of an area restricted from operation under section 12(d) of the act.

(b) As the need arises, the Bureau of Land Management will prepare official leasing maps of areas of the Outer Continental Shelf, which will be made to conform so far as practicable to the method of tract designation established by the adjoining State. The area included in each mineral lease shall be described in accordance with the official leasing map.

§ 3301.2 Resources evaluation.

From time to time the Director may announce tentative schedules of lease sales of Outer Continental Shelf areas. At such time as an area is initially considered for mineral leasing, or as the need arises, the Director shall request the Geological Survey to prepare a summary report describing the general geology and potential mineral resources of the area and shall request other interested Federal agencies to prepare reports describing to the extent known any other valuable resources contained within the general area and the potential effect of mineral operations upon the resources or upon the total environment.

§ 3301.3 Nominations of tracts.

In selecting tracts for oil and gas, sulphur, or other mineral leasing, the Director will receive and consider nominations of tracts or requests describing areas and expressing an interest in leasing of minerals, or, from time to time, upon his own motion, upon approval of the Secretary, may issue calls for nominations of tracts for the leasing of minerals in specified areas. Nominations of tracts should be addressed to the Director, with copies to the appropriate Bureau of Land Management field office and the appropriate oil and gas supervisor of the Geological Survey. The Director, Geological Survey, shall submit recommendations to the Director on tract selections and lease terms and conditions.

§ 3301.4 Selection of tracts.

The Director, prior to the final selection of tracts for leasing, either selected on his own motion or nominated pursuant to § 3301.3 of this subpart, shall evaluate fully the potential effect of the leasing program on the total environment, aquatic resources, aesthetics, recreation, and other resources in the entire area during exploration, development and operational phases. To aid him in his evaluation and determinations he shall request and consider the views and recommendations of appropriate Federal agencies, may hold public hearings after appropriate notice, and may consult with State agencies, organizations, industries, and individuals. The Director shall develop special leasing stipulations and conditions when necessary to protect the environment and all other resources, and such special stipulations and conditions shall be contained in the proposed notice of lease offer. The proposed notice of lease offer, together with all views and recommendations received and the Director's findings or actions thereon, shall be submitted to the Secretary for final approval.

§ 3301.5 Notice of lease offer.

Upon approval of the Secretary, the Director shall publish the notice of lease offer at the expense of the United States in the *Federal Register*, as the official publication, and in other publications as may be desirable. The publication in the *Federal Register* shall be at least 30 days prior to the date of the sale. The notice shall state the place and time at which bids will be filed, and the place, date, and hour at which bids will be opened. The notice shall contain any special stipulations or conditions which will become a part of any lease issued pursuant to such notice, including stipulations or conditions for the protection of the environment, aquatic life and other resources.

§ 3301.6 Tracts subject to drainage.

Upon direction of the Secretary, the Director, after obtaining the recommendation of the Director, Geological Survey, is authorized to publish on his own motion notices of lease offer of tracts which have been determined by the Director, Geological Survey, to be subject to drainage of their oil and gas deposits from wells on other tracts. The Director may request and consider the views and recommendations of appropriate Federal and State agencies prior to publishing the notice of lease offer. The notice shall be published in accordance with section 3301.5 of this subpart.

Subpart 3302—Issuance of Leases

§ 3302.1 General.

Tracts will be offered for lease by competitive sealed bidding under conditions specified in the notice of lease offer. Each oil and gas lease issued pursuant to section 8 of the act shall cover a compact area not exceeding 5,760 acres.

§ 3302.2 Term.

(a) All oil and gas leases shall be issued for a term of 5 years and so long thereafter as oil or gas may be produced from the leasehold in paying quantities, or drilling or well reworking operations, as approved by the Secretary under § 3305a.1 of this part, are conducted thereon.

(b) All sulphur leases shall be issued for a term of 10 years and so long thereafter as sulphur may be produced from the leasehold in paying quantities or drilling, well reworking, plant construction, or other operations for the production of sulphur, as approved by the Secretary, are conducted thereon.

(c) Other mineral leases shall be issued for such terms as may be prescribed at the time of offering the leases in the notice of lease offer.

§ 3302.4 What must accompany bids.

(a) A separate bid must be submitted for each lease unit described in the notice of lease offer. A bid may not be submitted for less than an entire unit. Each bidder must submit with his bid a certified or cashier's check or bank draft on a solvent bank, or a money order or cash, for one-fifth of the amount of the cash bonus. If the bidder is an individual, he must submit with his bid a statement of his citizenship. If the bidder is an association (including a partnership), the bid shall be accompanied also by a certified copy of the articles of association or appropriate reference to the record of the Bureau of Land Management in which such a copy has already been filed, with a statement as to any subsequent amendments. If the bidder is a corporation, the following additional information shall be submitted with the bid.

(1) A certified copy of the articles of incorporation and a copy either of the minutes of the meeting of the board of directors or of the by-laws indicating that the person signing the bid has authority to do so, or, in lieu of such a copy, a certificate by the secretary or the assistant secretary of the corporation to that effect, over the corporate seal or appropriate reference to the record of the Bureau of Land Management in connection with which such articles and authority have been previously furnished.

(b) All bidders are warned against violation of the provisions of Title 18 U.S.C. section 1860, prohibiting unlawful combination or intimidation of bidders.

§ 3302.5 Award of lease.

Sealed bids received in response to the notice of lease offer shall be opened at the place, date and hour specified in the notice. The opening of bids is for the sole purpose of publicly announcing and recording the bids received and no bids will be accepted or rejected at that time. In accordance with section 8 of the act, leases will be awarded only to the highest responsible qualified bidder. The United States reserves the right and discretion to reject any and all bids received for any tract, regardless of the amount offered. Awards of leases will be made only by written notice from the authorized officer. Such notice shall transmit the lease forms for execution. In the event the highest bids are tie bids, tie bidders may file with the Director within 15 days after notification an agreement to accept the lease jointly, otherwise all bids will be rejected. If the authorized officer fails to accept the highest bid for a lease within 30 days after the date on which the bids are opened, all bids for such lease will be considered rejected. Notice of his action will be transmitted promptly to the several bidders. If the lease is awarded, three copies of the lease will be sent to the successful bidder and he will be required not later than the 15th day after his receipt thereof, or the 30th day after the date of the sale, whichever is later, to execute them, pay the first year's rental, the balance of the bonus bid, and file a bond as required in § 3304.1. Deposits on rejected bids will be returned. If the successful bidder fails to execute the lease or otherwise comply with the applicable regulations, his deposit will be forfeited and disposed of as other receipts under the act. If before the lease is executed on behalf of the United States the land is withdrawn or restricted from leasing, all payments made by the bidder will be refunded. If the awarded lease is executed by an agent acting in behalf of the bidder, the lease must be accompanied by evidence that the bidder authorized the agent to execute the lease. When the three copies of the lease are executed by the successful bidder and returned to the authorized officer, the lease will be executed on behalf of the United States, and one fully executed copy will be mailed to the successful bidder.

§ 3302.6 Form.

Oil and gas leases and leases for sulphur will be issued on forms approved by the Director. Other mineral leases will be issued on such forms as may be prescribed by the Secretary.

§ 3302.7 Dating of leases.

All leases issued under the regulations in this part will be dated and become effective as of the firsts day of the month following the date the leases are signed on behalf of the lessor, except that, when prior written request is made, a lease may be dated and become effective as of the first day of the month within which it is so signed.

Subpart 3303—Rentals and Royalties

§ 3303.1 Rentals.

An annual rental shall be due and payable in advance on the first day of each lease year prior to discovery at the rate specified in the lease. The owner of any lease created by the assignment of a portion of a producing lease and on which assigned portion there is no discovery shall be required to pay an annual rental for such assigned portion at the rate per acre specified in the lease payable each lease year following the year in which the assignment became effective and prior to a discovery on such segregated portion.

§ 3303.2 Royalties.

Royalties shall be at the rate specified in the lease but in no event shall the royalty on oil and gas be less than 12½ percent of the amount or value of the production saved, removed or sold from the lease, nor on sulphur less than 5 percent of the gross production of value of the sulphur at the wellhead.

§ 3303.3 Minimum royalty.

Each lessee shall pay the minimum royalty specified in the lease at the end of each lease year beginning with the first lease year following a discovery on the lease.

§ 3303.5 Effect of suspensions on royalty and rental.

(a) In the event that under the provisions of 30 CFR 250.12(c) or (d)(1) the regional oil and gas supervisor of the Geological Survey with respect to any lease directs the suspension of both operations and production, or with respect to a lease on which there is no producible well directs the suspension of operations, no payment of rental or minimum royalty will be required for or during the period of the suspension. In the event that under the provisions of 30 CFR 250.12(d)(1) the supervisor approves, at the request of a lessee, the suspension of operations or production, or both, or under the provisions of 30 CFR 250.12(d)(3) suspends any operation including production, the lessee will not be relieved of the obligation to pay rental, minimum royalty or royalty for or during the period of suspension.

(b) In the event the anniversary date of a lease falls within a period of suspension for which no rental or minimum royalty payments are required under paragraph (a), of this section, the prorated rentals or minimum royalties, if any are due and payable as of the date the suspension period terminates, shall be computed and notice thereof given the lessee. Payment of the amount due shall be made by the lessee within 30 days after receipt of such notice. The anniversary date of a lease will not change by reason of any period of lease suspension or rental or royalty relief resulting therefrom.

Subpart 3304—Bonds

§ 3304.1 Amount of bond required of lessee.

The successful bidder prior to the issuance of an oil and gas or sulphur lease must furnish a corporate surety bond in the sum of $50,000 conditioned on compliance with all of the terms of the lease, unless he already maintains or furnishes a bond in the sum of $300,000 conditioned on compliance with the terms of oil and gas and sulphur leases held by him on the Outer Continental Shelf in the (a) Gulf of Mexico, (b) along the Pacific Coast, or (c) along the Atlantic Coast, as may be appropriate. An operator's bond in the same amount may be substituted at any time for the lessee's bond. The United States reserves the right to require additional security in the form of a supplemental bond or bonds or to increase the coverage of an existing bond if, after operations or production have begun, such additional security is deemed necessary. The amount of bond coverage on leases for other minerals will be determined at the time of the offer to lease and will be stated in the notice of a lease offer. Where upon a default, the surety on an Outer Continental Shelf Mineral Lease Bond makes payment to the Government of any indebtedness under a lease secured thereby, the face amount of such bond and the surety's liability thereunder shall be reduced by the amount of such payment. Thereafter, upon penalty of cancellation of all of the leases covered by such bond, the principal shall post a new bond, on a form approved by the Director, in the amount of $300,000 within 6 months after notice, or within such shorter period as the authorized officer of the Bureau of Land Management may fix. However, in lieu thereof, the principal may within that time file separate bonds for each lease. The provisions hereof may be made applicable to any bond in force at the time of the approval of the amendment of this section by filing in the local office of the Bureau of Land Management, a written consent to that effect and an agreement to be bound by the provisions hereof executed by the principal and surety. Upon receipt thereof the bond will be deemed to be subject to the provisions of this section.

§ 3304.2 Form of bond.

Bonds furnished by lessee or operator for a single lease will be on forms approved by the Director. The $300,000 bond will be on a form approved by the Director.

Subpart 3305—Assignment or Transfers

§ 3305.1 Assignment of leases or interest therein.

Leases, or any undivided interest therein, may be assigned in whole or as to any officially designated subdivision subject to the approval of the authorized officer, to any one qualified under § 3380.1 to take and hold a lease. Any assignment made under this section shall, upon approval, be deemed to be effective on and after the first day of the lease month following its filing in the appropriate office of the Bureau of Land Management, unless at the request of the parties an earlier date is specified in the Director's approval. The assignor shall be liable for all obligations under the lease accruing prior to the approval of the assignment.

§ 3305.2 Requirements for filing of transfers.

(a) (1) All instruments of transfer of a lease or of an interest therein, including operating agreements, subleases, and assignments of record interests, must be filed in triplicate for approval within 90 days from the date of final execution with a statement over the transferee's own signature with respect to citizenship and qualifications similar to that required of a lessee and must contain all of the terms and conditions agreed upon by the parties thereto. Carried working interests, overriding royalty interests, or payments out of production, may be created or transferred without requirement for filing or approval.

(2) An application for approval of any instrument required to be filed must be accompanied by a fee of $10, and an application not accompanied by payment of such a fee will not be accepted for filing. Such fee will not be returned even though the application later be withdrawn or rejected in whole or in part.

(b) Where an attorney in fact, in behalf of the holder of a lease, operating agreement or sublease signs an assignment of the agreement, lease, or interest, or signs the application for approval, there must be furnished evidence of the authority of the attorney in fact to execute the assignment or application and the statement requested by § 3302.4.

(c) Where an assignment creates a segregated lease a bond must be furnished in the amount prescribed in § 3304.1. Where an assignment does not create separate leases the assignee, if the assignment so provides and the surety consents, may become a joint principal on the bond with the assignor.

(d) In order for the heirs or devises of a deceased holder of a lease, or any interest therein, to be recognized by the Department as the lawful successor to such lease or interest, evidence of their status as such heirs or devisees must be furnished in the form of a certified copy of an appropriate order or decree of the court having jurisdiction of the distribution of the estate or, if no court action is necessary, the statements of two disinterested parties having knowledge of the facts or a certified copy of the will, and, in all cases, the statements of the heirs or devisees that they are the persons named as successors to the estate with evidence of their qualifications as provided in § 3302.4. In the event such heirs or devisees are unable to qualify to hold the lease or interest they will nevertheless be recognized as the lawful successors of the deceased for a period of not to exceed 2 years from the date of death of their predecessor in interest.

§ 3305.3 Separate assignments required for transfer of record title to leases.

A separate instrument of assignment must be filed for each lease when transfers involve record titles. When transfers to the same person, association, or corporation, involving more than one lease are filed at the same time for approval, one request for approval and one showing as to the qualifications of the assignee will be sufficient.

§ 3305.4 Effect of assignment of particular tract.

(a) When an assignment is made of all of the record title to a portion of the acreage in a lease, the assigned and retained portions become segregated into separate and distinct leases. The assignee becomes a lessee of the Government as to the segregated tract and is bound by the terms of the lease as though he had obtained the lease from the United States in his own name, and the assignment after its approval will be the basis of a new record. Royalty, minimum royalty, and rental provisions of the original lease shall apply separately to each segregated portion.

(b) In the case of an assignment of a portion of an oil and gas lease the segregated leases shall continue in full force and effect for the primary term of the original lease and so long thereafter as oil or gas may be produced from the original leased area in paying quantities or drilling or well reworking operations as approved by the Secretary are conducted thereon.

Subpart 3305a—Extension of Leases

§ 3305a.1 Extension of leases by drilling or well reworking operations.

(a) The Secretary shall be deemed to have approved, within the meaning of section 8(b) (2) of the Outer Continental Shelf Lands Act, drilling or well reworking operations, conducted on the leased area in the following instances:

(1) If, any discovery of oil or gas in paying quantities has been made on the leasehold, and within 90 days prior to expiration of the 5-year term or any extension thereof, or thereafter, the production thereof shall cease at any time, or from time to time, from any cause and production is restored or drilling or well reworking operations are commenced within 90 days thereafter, and such drilling or well reworking operations (whether on the same or different wells) are prosecuted diligently until production is restored in paying quantities.

(2) If, within 90 days prior to expiration of the 5-year term or any extension thereof, or thereafter, at any time, or from time to time, lessee is engaged in drilling or well reworking operations on the leasehold and there is no well on the leasehold capable of producing in paying quantities and the lessee diligently prosecutes such operations (whether on the same or different wells) with no cessation of more than 90 days.

(b) The Secretary may approve such other operations for drilling or reworking upon application of lessee.

(c) Nothing in this section obviates the necessity of obtaining the Oil and Gas Supervisor's approval of a plan or notice of intention to drill or of complying with the provisions of 30 CFR Part 250.

§ 3305a.2 Directional drilling.

A lease may be maintained in force by directional wells drilled under the leased area from surface locations on adjacent or adjoining land not covered by the lease. In such circumstances, drilling shall be considered to have commenced on the leased area when drilling is commenced on the adjacent or adjoining land for the purpose of directionally drilling under the leased area through any directional well surfaced on adjacent or adjoining land, and production, drilling, or reworking of any such directional well shall be considered production or drilling or reworking operations (as the case may be) on the leased area for all purposes of the lease.

§ 3305a.3 Compensatory payments.

In the event that an oil and gas lessee makes compensatory payments as provided in 30 CFR 250.33 and in the event that the lease is not being maintained in force by other production of oil or gas in paying quantities or by other approved drilling or reworking operations, such payments shall be considered as the equivalent of production in paying quantities for all purposes of the lease.

§ 3305a.4 Effect of suspensions on lease term.

In the event that under the provisions of 30 CFR 250.12(c) or (d)(1), the regional Oil and Gas Supervisor of the Geological Survey directs the suspension of either operations or production, or both, with respect to any lease, the term of the lease will be extended by a period equivalent to the period of the suspension. In the event that under the provisions of 30 CFR 250.12(c) or (d)(1), the supervisor approves the suspension of either operations or production, or both, with respect to any lease, the term of the lease will not be deemed to expire so long as the suspension remains in effect.

Subpart 3306—Termination of Leases

§ 3306.1 Relinquishment of leases or parts of leases.

A lease or any officially designated subdivision thereof may be surrendered by the record title holder by filing a written relinquishment, in triplicate, with the appropriate office of the Bureau of Land Management. A relinquishment shall take effect on the date it is filed subject to the continued obligation of the lessee and his surety to make payment of all accrued rentals and royalties and to abandon all wells on the land to be relinquished to the satisfaction of the Oil and Gas Supervisor.

§ 3306.2 Cancellation of leases.

Any nonproducing lease issued under the act may be canceled by the authorized officer whenever the lessee fails to comply with any provision of the act or lease or applicable regulations in force and effect on the date of the issuance of the lease, if such failure to comply continues for 30 days after mailing of notice by registered letter to the lease owner at his record post office address. Any such cancellation is subject to judicial review as provided in section 8(j) of the act upon the complaint of any person. Producing leases issued under the act may be canceled for such failure only by judicial proceedings in the manner prescribed in section 5(b)(2) of the act. Any lease issued under the act, whether producing or not, will be canceled by the authorized officer upon proof that it was obtained by fraud or misrepresentation, and after notice and opportunity to be heard has been afforded to the lessee.

Subpart 3307—Mineral Deposits Affected by Section 6 of Outer Continental Shelf Lands Act

§ 3307.1 Effect of regulations on provisions of lease.

(a) As contemplated by section 6(b) of the act, the preceding regulations in this part so far as they are applicable and the following regulations will supersede the provisions of any lease which is determined to meet the requirements of section 6(a) of the act, to the extent that they cover the same subject matter, with the following exceptions: The provisions of a lease with respect to the area covered by the lease, the minerals covered by the lease, the rentals payable under the lease, the royalties payable under the lease (subject to the provisions of sections 6(a)(8) and 6(a)(9) of the act), and the term of the lease (subject to the provisions of section 6(a)(10) of the act and, as to sulphur, subject to the provisions of section 6(b)(2) of the act) shall continue in effect and, in the event of any conflict or inconsistency, shall take precedence over those regulations.

(b) A lease that meets the requirements of section 6(a) of the act shall also be subject to all operating and conservation regulations applicable to the Outer Continental Shelf, as well as the regulations relating to geophysical and geological exploratory operations and to pipeline right-of-way in the Outer Continental Shelf, to the extent that those regulations are not contrary to or inconsistent with the provisions of the lease relating to the area covered, the minerals covered, the rentals payable, the royalties payable, and the term of the lease. Nothing herein should be construed to waive compliance with any provision of any State lease the subject matter of which is not covered in the regulations in this part.

§ 3307.2 Leases of other minerals.

The existence of a lease that meets the requirements of section 6(a) of the act will not preclude the issuance of other leases of the same area for deposits of other minerals: *Provided*, That no lease of minerals other than those covered by the lease shall authorize or permit the lessee thereunder unreasonably to interfere with or endanger operations under the existing lease: *And provided further*, That no sulphur leases will be granted by the United States on any area while such area is included in a lease covering sulphur under section 6(b) of the act.

§ 3307.3 Obligations of lessee.

§ 3307.3-1 Bonds.

Within 30 days from the effective date of the regulations in this part or within such further period or periods as may be fixed from time to time by the authorized officer, the lessee under a lease meeting the requirements of section 6(a) of the act must furnish a bond as provided in § 3304.1.

§ 3307.3-2 Wells.

(a) After due notice in writing, the lessee shall drill and produce such wells as the Secretary may reasonably require in order that the leased area or any part thereof may be properly and timely developed and produced in accordance with good operating practice.

(b) At the election of the lessee, the lessee may drill and produce other wells in conformity with any system of well spacing or production allotments affecting the area, filed, or pool in which the leased area or any part thereof is situated, which is authorized or sanctioned by applicable law or by the Secretary.

(c) The lessee shall drill and produce such wells as are necessary to protect the lessor from loss by reason of production on other properites, or in lieu thereof, with the consent of the Oil and Gas Supervisor, to pay a sum determined by the supervisor as adequate to compensate the lessor for failure to drill and produce any such well. In the event that this lease is not being maintained in force by other production of oil or gas in paying quantities or by other approved drilling or reworking operations, such payments shall be considered as the equivalent of production in paying quantities for all purposes of this lease.

§ 3307.3-3 Inspection.

The lessee shall keep open at all reasonable times for the inspection of any duly authorized officer of the Department of the Interior, the leased area and all wells, improvements, machinery and fixtures thereon and all books, accounts, maps and records relative to operations and surveys or investigations on or with regard to the leased area or under the lease.

§ 3307.3-4 Diligence; compliance with regulations and orders.

The lessee shall exercise reasonable diligence in drilling and producing the wells herein provided for; shall carry on all operations in accordance with approved methods and practices including those provided in the operating and conservation regulations for the Outer Continental Shelf; shall remove all structures when no longer required for operations under the lease to sufficient depth beneath the surface of the waters to prevent them from being a hazard to navigation and the fishing industry; and shall carry out at expense of the lessee all lawful and reasonable orders of the lessor relative to the matters in this section. On failure of the lessee so to do the lessor shall have the right to enter on the property and to accomplish the purpose of such orders at the lessee's cost: *Provided*, That the lessee shall not be held responsible for delays or casualties occasioned by causes beyond the lessee's control.

§ 3307.3-5 Freedom of purchase.

The lessee shall accord all workmen and employees directly engaged in any of the operations under the lease complete freedom of purchase.

§ 3307.3-6 Removal of property on termination of lease.

Upon the expiration of any lease, or the earlier termination thereof as provided in the regulations in this part, the lessee shall within a period of one year thereafter remove from the premises all structures, machinery, equipment, tools, and materials other than improvements needed for producing wells or for drilling or producing other leases, and other property permitted by the lessor to be maintained.

§ 3307.4 Exploration and operations.

§ 3307.4-1 Purchase of production.

In time of war, or when the President of the United States shall so prescribe, the United States shall have the right of first refusal to purchase at the market price all or any portion of the oil or gas produced from the leased area, as provided in section 12(b) of the act.

§ 3307.4-2 Suspension of operations during war or national emergency.

Upon recommendation of the Secretary of Defense, during a state of war or national emergency declared by the Congress or the President of the United States after August 7, 1953, the Secretary is authorized to suspend any or all operations under a lease, as provided in section 12(c) of the act: *Provided*, That just compensation shall be paid by the United States to the lessee whose operations are thus suspended.

§ 3307.4-3 Restriction of exploration and operations.

The United States shall have the right, as provided in section 12(d) of the act, to restrict from exploration and operations the leased area or any part thereof which may be designated by and through the Secretary of Defense, with the approval of the President of the United States, as, or as part of, an area of the Outer Continental Shelf needed for national defense. So long as such designation remains in effect no exploration or operations may be conducted on the surface of the leased area or the part thereof included within the designation except with the concurrence of the Secretary of Defense. If operations or production under any lease within any such restricted area shall be suspended, any payments of rentals, minimum royalty, and royalty prescribed by such lease likewise shall be suspended during such period of suspension of operations and production, and the term of such lease shall be extended by adding thereto any such suspension period, and the United States shall be liable to the lessee for such compensation as is required to be paid under the Constitution of the United States.

§ 3307.4-4 Geological and geophysical exploration; rights-of-way.

The United States reserves the right to authorize the conduct of geological and geophysical exploration in the leased area which does not interfere with or endanger actual operations under the lease and the right to grant such easements or rights-of-way, upon, through, or in the leased area as may be necessary or appropriate to the working of other lands containing the deposits described in the act, and to the treatment and shipment of products thereof by or under authority of the Government, its lessees or permittees, and for other public purposes, subject to the provisions of section 5(c) of the act where they are applicable and to all lawful and reasonable regulations and conditions prescribed by the Secretary thereunder.

§ 3307.4-5 Leases of sulphur and other mineral.

The United States reserves the right to grant sulphur leases and leases of any mineral other than oil, gas, and sulphur within the leased area or any part thereof, subject to the provisions of sections 8(c), 8(d), and 8(e) of the act and all lawful and reasonable regulations prescribed by the Secretary thereunder: *Provided*, That no such sulphur lease or lease of other mineral shall authorize or permit the lessee thereunder unreasonably to interfere with or endanger operations under the lease which is continued under section 6 of the act.

§ 3307.5 Remedies in case of default.

(a) Whenever the lessee fails to comply with any of the provisions of the act or of the lease or of the lawful and reasonable regulations issued within 90 days after the authorized officer has determined that the lease meets the requirements of section 6(a) of the act, the lease shall be subject to cancellation as follows:

(1) If, at the time of such default, no well is producing, or is capable of producing, oil or gas in paying quantities from the leased area, whether such well be drilled from a surface location within the leased area or be directionally drilled from a surface location on adjacent or adjoining lands the lease may be canceled by the Secretary (subject to the right of judicial review as provided in section 8(j) of the act) if such default continues for the period of 30 days after mailing of notice by registered letter to the lessee at the lessee's record post office address.

(2) If, at the time of such default, any well is producing, or is capable of producing, oil or gas in paying quantities from the leased area, whether such well be drilled from a surface location within the leased area or be directionally drilled from a surface location on adjacent or adjoining lands, the lease may be canceled by an appropriate proceeding in any United States district court having jurisdiction under the provisions of section 4(b) of the act if such default continues for the period of 30 days after mailing of notice by registered letter to the lessee at the lessee's record post office address.

(b) If any such default continues for the period of 30 days after mailing of notice by registered letter to the lessee at the lessee's record post office address, the lessor may then exercise any legal or equitable remedy which the lessor may have; however, the remedy of cancellation of the lease may be exercised only under the conditions and subject to the limitations set out in paragraph (a) of this section, or pursuant to section 8(i) of the act.

(c) A waiver of any particular default shall not prevent the cancellation of the lease or the exercise of any other remedy the lessor may have by reason of any other cause or for the same cause occurring at any other time.

§ 3307.6 Heirs and successors in interest.

Each obligation under any lease and under the regulations in this part shall extend to and be binding upon, and every benefit thereunder shall inure to, the heirs, executors, administrators, successors, or assigns of the lessee.

[From Federal Register, Vol. 40, No. 191, Wednesday, Oct. 1, 1975]

APPENDIX XIV. AMENDED TITLE 43 FEDERAL REGULATIONS PERTAINING TO OUTER CONTINENTAL SHELF LEASING QUALIFIED JOINT BIDDERS

TITLE 43—PUBLIC LANDS: INTERIOR

CHAPTER II—BUREAU OF LAND MANAGEMENT

PART 3300—OUTER CONTINENTAL SHELF LEASING; GENERAL

Qualified joint bidders

Pursuant to the authority vested in the Secretary of the Interior with respect to the promulgation and amendment of regulations necessary to carry out the provisions of the Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1331–1343 (1970), the existing regulations in 43 CFR Subparts 3300, 3302, and 3305 are hereby amended with the objective of improving competitive bidding for oil and gas leases granted on submerged lands of the Outer Continental Shelf.

In keeping with the Department of Interior's announced policy of affording the public an opportunity to participate in the rulemaking process, proposed regulations for this purpose were published in the *Federal Register* on April 24, 1974 (39 FR 14511), and a public hearing was held on June 25, 1974. Revised proposed regulations were published in the *Federal Register* on February 21, 1975 (40 FR 7673), and written comments were requested from all interested persons. The extensive comments received have been reviewed by the Department, and the proposed regulations published on February 21, 1975, have been revised again.

As now revised, the regulations will not require the submission of a detailed Report of Production in order to qualify for joint bidding at an OCS oil and gas lease sale, but instead will merely require a Statement of Production to be filed, indicating whether or not the prospective joint bidder is chargeable with an average daily worldwide production in excess of 1.6 million barrels of crude oil, natural gas, and liquefied petroleum products. The Director of the Bureau of Land Management will, however, retain his right to require the filing of a detailed Report of Production when needed to substantiate any statement made in the Statement of Production.

It has been determined that the promulgation of the following regulations is not a major federal action significantly affecting the quality of the human environment and thus no environmental impact statement is required, nor is an inflationary impact statement required.

The following regulations are issued as final rule making, effective immediately.

1. Section 3300.1 is amended to read as follows:

§ 3300.1 Persons qualified to hold leases.

Mineral leases issued pursuant to section 8 of the Act may be held only by citizens and nationals of the United States, aliens lawfully admitted for permanent residence in the United States as defined in 8 U.S.C. § 1101(a)(20) private, public, or municipal corporations organized under the laws of the United States or of any State or Territory thereof, or associations of such citizens, nationals, resident aliens, or private, public, or municipal corporations, States, or political subdivisions of States.

2. Section 3302.1 is amended to read as follows:

§ 3302.1 General.

Tracts will be offered for lease by competitive sealed bidding under conditions specified in the Notice of Lease Offer and in accordance with the provisions of §§ 3300.1, 3302.2, 3302.3 and 3302.4 of this Part. Each oil and gas lease issued pursuant to section 8 of the Act shall cover a compact area not exceeding 5,760 acres.

3. The following new sections are added to Subpart 3302 which reads as follows:

§ 3302.3 Qualified bidders.

§ 3302.3–1 Definitions.

The following definitions shall be applicable to § 3302.3:

(a) "*Single bid*" means a bid submitted by one person for an oil and gas lease under section 8(a) of the Act.

(b) "*Joint bid*" means a bid submitted by two or more persons for an oil and gas lease under section 8(a) of the Act.

(c) "*Average Daily Production*" is the total of all production in an applicable production period which is chargeable under section 3302.3–3 divided by the exact number of calendar days in the applicable production period.

(d) "*Barrel*" means 42 United States gallons.

(e) "*Crude Oil*" means a mixture of liquid hydrocarbons including condensate that exists in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities, but does not include liquid hydrocarbons produced from tar sands, gilsonite, oil shale, or coal.

(f) "*An Economic Interest*" means any right to, or any right dependent upon, production of crude oil, natural gas, or liquefied petroleum products and shall include, but not be limited to, a royalty interest, or overriding royalty interest, whether payable in cash or in kind, a working interest, a net profits interest, a production payment, or a carried interest.

(g) "*Liquefied Petroleum Products*" means natural gas liquid products including the following: ethane, propane, butane, pentane, natural gasoline, and other natural gas products recovered by a process of absorption, adsorption, compression, or refrigeration cycling, or a combination of such processes.

(h) "*Natural Gas*" means a mixture of hydrocarbons and varying quantities of nonhydrocarbons that exist in the gaseous phase.

(i) "*Oil and Gas Lease*" means an oil and gas lease either offered or issued pursuant to the provisions of the Act.

(j) "*Owned*" means:

(1) *With respect to crude oil*—having either an economic interest in or a power of disposition over the production of crude oil;

(2) *With respect to natural gas*—having either an economic interest in or a power of disposition over the production of natural gas; and

(3) *With respect to liquefied petroleum products*—having either an economic interest in or a power of disposition over any liquefied petroleum product at the time of completion of the liquefaction process.

(k) "*Prior Production Period*" means the continuous six month period of January 1 through June 30 preceding November 1 through April 30 for joint bids submitted during the six month bidding period from November 1 through April 30, and means the continuous six month period of July 1 through December 31 preceding May 1 through October 31 for joint bids submitted during the six month bidding period from May 1 through October 31.

(l) "*Production*"—(1) *of crude oil* means the volume of crude oil produced worldwide from reservoirs during the prior production period. The amount of such crude oil production shall be established by measurement of volumes delivered at the point of custody transfer (e.g., from storage tanks to pipelines, trucks, tankers, or other media for transport to refineries or terminals) with adjustments for

(i) Net differences between opening and closing inventories, and

(ii) Basic sediment and water;

(2) *Of natural gas* means the volume of natural gas produced worldwide from natural oil and gas reservoirs during the prior production period, with adjustments, where applicable, to reflect

(i) The volume of gas returned to natural reservoirs; and

(ii) The reduction of volume resulting from the removal of natural gas liquids and nonhydrocarbon gases.

(3) *Of liquefied petroleum products* means the volume of natural gas liquids produced from reservoir gas and liquefied at surface separators, field facilities, or gas processing plants worldwide during the prior production period; these liquefied petroleum products include the following:

(i) *Condensate*—natural gas liquids recovered from gas well gas (associated and non-associated) in separators or field facilities;

(ii) *Gas Plant Products*—natural gas liquids recovered from natural gas in gas processing plants and from field facilities. Gas plant products shall include the following as classified according to the standards of the Naural Gas Processors Association (NGPA) or the American Society for Testing and Materials (ASTM):

(A) Ethane—C_2H_6;

(B) Propane—C_3H_8;

(C) Butane—C_4H_{10} including all products covered by NGPA specifications for commercial butane.

(1) Isobutane,

(2) Normal butane,

(3) Other butanes—all butanes not included as isobutane or normal butane;

(D) Butane-Propane Mixtures—All products covered by NGPA specifications for butane-propane mixtures;

(E) Natural Gasoline—A mixture of hydrocarbons extracted from natural gas, which meet vapor pressure, end point, and other specifications for natural gasoline set by NGPA;

(F) Plant Condensate—A natural gas plant product recovered and separated as a liquid at gas inlet separators or scrubbers in processing plants or field facilities; and

(G) Other Natural Gas Plant Products meeting refined product standards (i.e., gasoline, kerosene, distillate, etc.).

(m) "*Six Month Bidding Period*" means the six month period of time

(1) From May 1 through October 31; or

(2) From November 1 through April 30, respectively.

§ 3302.3–2 Joint bidding requirements.

(a) Any person who submits a joint bid for any oil and gas lease during a six month bidding period must have filed under oath with the Director a Statement of Production of crude oil, natural gas, and liquefied petroleum products, hereinafter referred to as a Statement of Production, no later than 45 days prior to the commencement of the applicable six month bidding period, except that for the initial bidding period commencing November 1, 1975, all Statements of Production must be filed no later than October 20, 1975. Statements of Production should be filed with the Director, Bureau of Land Management (attention 722), Washington, D.C. 20240. A Statement of Production shall state whether or not the person filing the Statement of Production was chargeable in accordance with § 3302.3–3 with an average daily production in excess of 1.6 million barrels of crude oil, natural gas, and liquefied petroleum products for the prior production period. The Director will, no less than semi-annually, publish in the Federal Register a "List of Restricted Joint Bidders," to be effective immediately upon publication and to continue in force and effect until a subsequent list is published. The List of Restricted Joint Bidders shall be made up of those persons who in the judgment of the Director, based on information available to him, including but not limited to, sworn Statements of Production, are chargeable under § 3302.3–3 with an average daily production in excess of 1.6 million barrels of crude oil, natural gas, and liquefied petroleum products for the prior production period.

(b) When a person is placed on the List of Restricted Joint Bidders the Director shall serve that person either personally or by certified mail, return receipt requested, with a copy of the Director's Order placing that person on the List of Restricted Joint Bidders. Any appeal from that Order or from an adverse effect of that Order shall be made in accordance with the provisions of 43 CFR Part 4.

(c) The submission of a Statement of Production or of a detail Report of Production under § 3302.4(d) which misrepresents the chargeable production of the reporting person shall constitute failure to comply with these regulations and any lease awarded in reliance on that Statement or Report of Production may be canceled, pursuant to section 8(i) of the Act and regulations issued thereunder as having been obtained by fraud or misrepresentation.

§ 3302.3–3 Chargeability for production.

(a) As used in this section the following definitions shall control:

(1) "*Person*" means a natural person or company.

(2) "*Company*" means a corporation, a partnership, an association, a joint-stock company, a trust, a fund, or any group of persons whether incorporated or not; it also means any receiver, trustee in bankruptcy, or similar official acting for such a company.

(3) "*Subsidiary*" means a company 50 percent or more of whose stock or other interest having power to vote for the election of directors, trustees, or other similar controlling body of the company is directly or indirectly owned, controlled, or held with the power to vote by another company; a subsidiary shall be deemed a subsidiary of the other company owning, controlling, or holding 50 percent or more of the stock or other voting interest.

(4) "*Security or securities*" means any note, stock, treasury stock, bond, debenture, evidence of indebtedness, certificate of interest or participation in any profit-sharing agreement, collateraltrust certificate, pre-organization certificate or subscription, transferable share, investment contract, voting-trust certificate, certificate of deposit for a security, fractional undivided interest in oil, gas, or other mineral rights, or, in general, any interest or instrument commonly known as a "security" or any certificate of interest or participation in, temporary or interim certificate for, receipt for, guarantee of, or warrant or right to subscribe to or purchase any of the foregoing.

(b) A person filing a Statement of Production under § 3302.3–2 shall be charged with the following production during the applicable prior production period:

(1) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products which it owned worldwide;

(2) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by every subsidiary of the reporting person;

(3) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by any person or persons of which the reporting person is a subsidiary; and

(4) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by any subsidiary, other than the reporting person, of any person or persons of which the reporting person is a subsidiary.

(c) A person filing a Statement of Production shall be charged with, in addition to the production chargeable under paragraph (b) of this section, but not in duplication thereof, its proportionate share of the average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by every person: (1) Which has an interest in the reporting person, and (2) in which the reporting person has an interest, whether the interest referred to in paragraphs (c) (1) and (2) of this section is by virtue of ownership of securities or other evidence of ownership, or by participation in any contract, agreement, or understanding respecting the control of any person or of any person's production of crude oil, natural gas, or liquefied petroleum products, equal to said interest. As used in paragraph (c) of this section "interest" means an interest of at least 5 percent of the ownership or control of a person.

(d) All measurements of crude oil and liquefied petroleum products under this section shall be at 60° F.

(e) (1) For purposes of computing production of natural gas under § 3302.3–2, chargeability under this section, and reporting under § 3302.4(d), 5.626 cubic feet of natural gas at 14.73 pounds per square inch (msl) shall equal one barrel.

(2) For purposes of computing production of liquefied petroleum products under § 3302.3–2, chargeability under this section, and reporting under § 3302.4(d), 1.454 barrels of natural gas liquids at 60° F shall equal one barrel of crude oil.

§ 3302.3–4 Bids disqualified.

The following bids for any oil and gas lease will be disqualified and rejected in their entirety;

(a) A joint bid submitted by two or more persons who are on the effective List of Restricted Joint Bidders; or

(b) A joint bid submitted by two or more persons when one or more of those persons has not filed the required Statement of Production pursuant to § 3302.3-2 for the applicable six month bidding period, or when one or more of those persons has failed or refused to file a detailed Report of Production when required to do so under § 3302.4(d); or

(c) A single or joint bid submitted pursuant to an agreement (whether written or oral, formal or informal, entered into or arranged prior to or simultaneously with the submission of such single or joint bid, or prior to or simultaneously with the award of the bid upon the tract) which provides (1) for the assignment, transfer, sale, or other conveyance or less than a 100 percent interest in the entire tract on which the bid is submitted, by a person or persons on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to another person or persons on the same List of Restricted Joint Bidders; or (2) for the assignment, sale, transfer or other conveyance of less than a 100 percent interest in any fractional interest in the entire tract (which fractional interest was originally acquired by the person making the assignment, sale, transfer or other conveyance, under the provisions of the Act) by a person or persons on the List of Restricted Joint Bidders, effective on the date of submision of the bid, to another person or persons on the same List of Restricted Joint Bidders; or (3) for the assignment, sale, transfer, or other conveyance of any interest in a tract by a person or persons not on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to two or more persons on the same List of Restricted Joint Bidders; or (4) for any of the types of conveyance described above in Paragraph (c) (1), (2), or (3) where any party to the conveyance has not filed a Statement of Production pursuant to § 3302.3-2 for the applicable six month bidding period. Assignments expressly required by law, regulation, lease, or stipulation to lease shall not disqualify an otherwise qualified bid; or

(d) A bid submitted by or in conjunction with a person who has filed a false, fraudulent or otherwise intentionally false or misleading Statement of Production or detalied Report of Production.

4. Section 3302.4 is amended by adding paragraphs (c) and (d) as follows:

§ 3302.4 What must accompany bids.

(c) In addition to the above, every joint bid submitted for any oil and gas lease shall be accompanied by a sworn statement by each joint bidder stating that the bid is not disqualified under § 3302.3-4(c).

(d) To verify the accuracy of any statement submitted pursuant to §§ 3302.3-2 and paragraph (c) of this section the Director may require the person submitting such information to (1) submit no later than 30 days after receipt of request by the Director a detailed Report of Production which shall list in barrels the average daily production of crude oil, natural gas, and liquefied petroleum products chargeable to the reporting person in accordance with § 3302.3-3 for the prior production period, and (2) permit the inspection and copying by an official of the Department of the Interior of such documents, records of production of crude oil, natural gas, and liquefied petroleum products, analyses and other material as are necessary to demonstrate the accuracy of any statement or information upon which any information in any Statement of Production or Report of Production was based or from which it was derived.

5. Section 3302.5 is amended to read as follows:

§ 3302.5 Award of leases.

Sealed bids received in response to the Notice of Lease Offer shall be opened at the place, date and hour specified in the notice. The opening of bids is for the sole purpose of publicly announcing and recording the bids received and no bids will be accepted or rejected at that time. In accordance with section 8 of the Act, leases will be awarded only to the highest qualified responsible bidder. The United States reserves the right and discretion to reject any and all bids received for any tract, regardless of the amount offered. Awards of leases will be made only by written notice from the authorized officer. Such notices shall transmit the lease forms for execution. In the event the highest bids are tie bids, the bidders, unless they would be disqualified under § 3300.1, or disqualified under § 3302.3-4 if their bids had been a joint bid, may file with the Director, within 15 days after notification, an agreement to accept the lease jointly; otherwise all bids will be rejected. If the authorized officer fails to accept the highest bid for a lease within

30 days after the date on which the bids are opened all bids for that lease will be considered rejected. Notice of his action will be transmitted promptly to the several bidders. If the lease is awarded, three copies of the lease will be sent to the successful bidder and he will be required not later than the 15th day after his receipt thereof, or the 30th day after the date of the sale, whichever is later, to execute them, pay the first year's rental and the balance of the bonus bid, and file a bond as required in § 3304.1. Deposits on rejected bids will be returned. If the successful bidder fails to execute the lease within the prescribed time or otherwise comply with the applicable regulations his deposit will be forfeited and disposed of as other receipts under the Act. If before the lease is executed on behalf of the United States the land which would be subject to the lease is withdrawn or restricted from leasing, the bidder will lose all right to the lease and all payments made by the bidder will be refunded to him. If the awarded lease is executed by an agent acting in behalf of the bidder, the lease must be accompanied by evidence that the bidder authorized the agent to execute the lease. When the three copies of the lease are executed by the successful bidder and returned to the authorized officer, the lease will be executed on behalf of the United States, and one fully executed copy will be mailed to the successful bidder.

Subpart 3305—Assignments or Transfers

6. Section 3305.1 is amended to read as follows:

§ 3305.1 Assignment of leases or interests therein.

Leases, or any undivided interest therein, may be assigned in whole, or as to any officially designated subdivision, subject to the approval of the authorized officer, to any one qualified under § 3300.1 to take and hold a lease. An assignment pursuant to any pre-lease agreement described in § 3302.3–4(c) as causing a bid to be disqualified will be void. Any assignment made under this section shall, upon approval, be deemed to be effective on and after the first day of the lease month following its filing in the appropriate office of the Bureau of Land Management, unless at the request of the parties an earlier date is specified in the Director's approval. The assignor shall be liable for all obligations under the lease accruing prior to the approval of the assignment.

7. Section 3305.2 is amended by the addition of a new paragraph (e) as follows:

§ 3305.2 Requirements for filing of transfers.

* * * * * * *

(e) Where the proposed assignment or transfer is by a person who, at the time of acquisition of his interest in the lease, was on the List of Restricted Joint Bidders, and that assignment or transfer is of less than the entire interest of the assignor or transferor, to a person or persons on the same List or Restricted Joint Bidders, the assignor or transferor must file a copy, prior to approval of the assignment, of all agreements applicable to the acquisition of that lease or a fractional interest therein.

Dated: September 26, 1975.

ROYSTON C. HUGHES,
Assistant Secretary of the Interior.

[FR Doc.75-26212 Filed 9-30-75; 8:45 am]

[From Part 250, Title 30, of the Code of Federal Regulations]

APPENDIX XV. REGULATIONS PERTAINING TO OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

PART 250—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

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MINERAL LEASES AFFECTED BY SECTION 6 OF OUTER CONTINENTAL SHELF LANDS ACT

250.100 Effect of regulations on provisions of lease.

AUTHORITY: The provisions of this Part 250 issued under secs. 5, 6, 67 Stat. 464, 465; 43 U.S.C. 1334, 1335.

CROSS REFERENCE: For further regulations pertaining to the issuance and recognition of mineral leases covering submerged lands in the outer Continental Shelf, see 43 CFR Part 3300.

GENERAL PROVISIONS

§ 250.1 Purpose and authority.

The Outer Continental Shelf Lands Act enacted on August 7, 1953 (67 Stat. 462), referred to in this part as "the act," authorizes the Secretary of the Interior at any time to prescribe and amend such rules and regulations, to be applicable to all operations conducted under a lease issued or maintained under the provisions of the act, as he determines to be necessary and proper to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf, and the protection of correlative rights therein. Subject to the supervisory authority of the Secretary of the Interior, the regulations in this part shall be administered by the Director of the Geological Survey through the Chief, Conservation Division.

[34 F.R. 13544, Aug. 22, 1969]

§ 250.2 Definitions.

The following terms as used in the regulations in this part shall have the meanings here given:

(a) *Secretary.* The Secretary of the Interior.

(b) *Director.*—The Director of the Geological Survey, Washington, D.C., having direction of the enforcement of the regulations in this part.

(c) *Supervisor.*—The Area Oil and Gas Supervisor, Conservation Division of the Geological Survey; a representative of the Secretary, subject to the direction and supervisory authority of the Director, the Chief, Conservation Division, Geological Survey, and the appropriate Conservation Manager, Conservation Division, Geological Survey, authorized and empowered to regulate operations and to perform other duties prescribed in the regulations in this part or any subordinate of such representative acting under his direction.

(d) *Outer Continental Shelf.* All submerged lands (1) which lie seaward and outside of the area of lands beneath navigable waters as defined in the Submerged Lands Act (67 Stat. 29) and (2) of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(e) *Lease.* The contract or agreement under which the leasehold rights are held by the lessee, or the land covered by the contract or agreement, whichever is required by the context.

(f) *Lessee.* The party authorized by a lease, or an approved assignment thereof, to develop and produce the leased deposits in accordance with the regulations in this part, including all parties holding such authority by or through him.

(g) *Operator.* The individual, partnership, firm, or corporation having control or management of operations on the leased land or a portion thereof. The operator may be a lessee, designated agent of the lessee, or holder of rights under an approved operating agreement.

(h) *Waste of oil and gas.* Waste means and includes (1) physical waste as that term is generally understood in the oil and gas industry; (2) the inefficient, excessive, or improper use of, or the unnecessary dissipation of reservoir energy; (3) the locating, spacing, drilling, equipping, operating, or producing of any oil or gas well or wells in a manner which causes or tends to cause reduction in the quantity of oil or gas ultimately recoverable from a pool under prudent and proper operations or which causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas; (4) the inefficient storage of oil; and (5) the production of oil or gas in excess of transportation or marketing facilities or in excess of reasonable market demand.

(i) *Directional drilling.* The deviation of a bore hole from the vertical or from its normal course in an intended predetermined direction or course with respect to the points of the compass. Directional drilling shall not include deviations made for the purpose of straightening a hole that has become crooked in a normal course of drilling or deviating a hole at random without regard to compass direction in an attempt to sidetrack a portion of the hole on account of mechanical difficulty in drilling.

(j) *OCS Order.* A formal numbered order issued by the supervisor and available in his office, with the prior approval of the Chief, Conservation Division, Geological Survey, that implements the regulations in this part and applies to operations in a region or a major portion thereof.

(k) *Pollution Contingency Plan.* The National Multi-Agency Oil and Hazardous Materials Pollution Contingency Plan cosigned by the Department of the Interior, Department of Transportation, Department of Defense, Department of Health, Education, and Welfare, and the Office of Emergency Preparedness and administered by the Secretary of the Interior, or any successor plan thereto.

[19 F.R. 2656, May 8, 1954, as amended at 34 FR 13544, Aug. 22, 1969; 38 FR 10001, Apr. 23, 1973]

JURISDICTION AND FUNCTIONS OF SUPERVISOR

§ 250.10 Jurisdiction.

Subject to the supervisory authority of the Secretary and the Director, drilling and production operations, handling, and measurement of production, determination and collection of rental and royalty, and in general, all operations conducted on a lease by or on behalf of a lessee are subject to the regulations in this part, and are under the jurisdiction of the Supervisor for any area as delineated by the Director. In the exercise of this jurisdiction, the Supervisor shall be subject to the direction and supervisory authority of the Chief, Conservation Division and the appropriate Conservation Manager, Conservation Division, Geological Survey, each of whom may exercise the jurisdiction of the Supervisor.

[38 FR 10001, Apr. 23, 1973]

§ 250.11 General functions.

The supervisor is authorized and directed to act upon the requests, applications, and notices submitted under the regulations in this part and to require compliance with applicable laws, the lease terms, applicable regulations, and OCS Orders to the end that all operations which shall be conducted in a manner which will protect the natural resources of the Outer Continental Shelf and result in the maximum economic recovery of the mineral resources in a manner compatible with sound conservation practices. Subject to the approval of the Chief, Conservation Division, Geological Survey, the supervisor may issue OCS Orders implementing the requirements of the regulations of this part when such implementations apply to an entire region or a major portion thereof. The supervisor may issue written or oral orders to govern lease operations. Oral orders shall be confirmed in writing by the supervisor as promptly as possible. The supervisor may issue other orders, and rules to govern the development and method of production of a pool, field, or area. Prior to the issuance of OCS Orders and other orders and rules, the supervisor may consult with, and receive comments from, lessees, operators, and other interested parties. Before permitting operations on the leased land, the supervisor may require evidence that a lease is in good standing, that the lessee is authorized to conduct operations, and that an acceptable bond has been filed.

[34 F.R. 13544, Aug. 22, 1969]

§ 250.12 Regulation of operations.

(a) *Duties of supervisor.* The supervisor in accordance with the regulations in this part shall inspect and regulate all operations and is authorized to issue OCS Orders and other orders and rules necessary for him to effectively supervise operations and to prevent damage to, or waste or, any natural resource, or injury to life or property. The supervisor shall receive, and shall, when in his judgment it is necessary, consult with or solicit advice from lessees, field officials of interested Departments and agencies, including the Fish and Wildlife Service, Federal Water Pollution Control Administration, Bureau of Land Management, Coast Guard, Department of Defense, Corps of Engineers, and representatives of State and local governments.

(b) *Departures from orders.* (1) The supervisor may prescribe or approve in writing, orally with written confirmation, minor departures from the requirements of OCS Orders and other orders and rules issued pursuant to (a) of this section, when such departures are necessary for the proper control of a well, conservation of natural resources, protection of aquatic life, protection of human health and safety, property, or the environment.

(2) All requests or recommendations for major departures from the requirements of OCS Orders, whether on an individual well or field basis, shall be approved by the Chief, Conservation Division.

(c) *Emergency suspensions.* The supervisor is authorized, either in writing or orally with written confirmation, to suspend any operation, including production, which in his judgment threatens immediate, serious, or irreparable harm or damage to life, including aquatic life, to property, to the leased deposits, to other valuable mineral deposits or to the environment. Such emergency suspension shall continue until in his judgment the threat or danger has terminated.

(d) *Other suspensions.* (1) In addition to the provisions of section 12 (c) and (d) of the act providing for suspension of operations and production, in the interest of conservation the supervisor may direct or, at the request of a lessee, may approve the suspension of operations or production, or both, including the approval of suspension of production for (i) leases on which a well has been drilled and determined by the supervisor to be capable of being produced in paying quantities and thereafter temporarily abandoned or permanently plugged and abandoned to facilitate proper development of the lease, and (ii) leases on which a well has been drilled and determined by the supervisor to be capable of being produced in paying quantities, but which cannot be produced because of the lack of transportation facilities. Suspensions of operations or production, or both, may be approved for an initial period, not exceeding 2 years, and for succeeding periods, not exceeding 1 year each.

(2) As to any leases maintained under section 6 of the act covering minerals in addition to oil and gas, the supervisor may suspend operations separately as to oil and gas or as to any other mineral designated in the suspension, order, or grant.

(3) The supervisor is authorized by written notice to the lessee to suspend any operation, including production, for failure to comply with applicable law, the lease terms, the regulations in this part, OCS orders, or any other written order or rule including orders for filing of reports and well records or logs within the time specified.

(e) *Reduction of rental and royalty.* In order to increase the ultimate recovery of minerals and in the interest of conservation, the Director of the Geological Survey, whenever he determines it necessary to promote development or finds that a lease cannot be successfully operated under the terms provided therein, may reduce the rental, minimum royalty, or royalty on the entire leasehold, or on any deposit, tract, or portion thereof segregated for royalty purposes. An application for any of the above relief shall be filed in triplicate with the Director of the Geological Survey. It must contain the serial number of the lease; the name of the record title holder; a description of the area included in the lease; the number, location, and status of each well that has been drilled; a tabulated statement for each month, covering a period of not less than 6 months prior to the date of filing the application, of the aggregate amount of minerals subject to royalty computed in accordance with the lease and applicable regulations. Every application must also contain a detailed statement of expenses and costs of operating the entire lease and of the income from the sale of any leased products, and all facts tending to show whether the wells or workings can be successfully operated upon the rental or royalty fixed in the lease. Where the application is for a reduction of royalty, full information shall be furnished as to whether royalties or payments out of production are paid to others than the United States, the amounts so paid, and efforts made to reduce them. The applicant must also file agreements of the holders of the lease and of royalty holders to a permanent reduction of all other royalties from the leasehold to an aggregate not in excess of one-half the Government royalties.

[34 F.R. 13544, Aug. 22, 1969]

§ 250.13 Temporary approvals.

Whenever the regulations in this part require a lessee to obtain appproval of the supervisor, the lessee may make an oral or telegraphic request for such approval, and the supervisor may give such oral or telegraphic approval as may be warranted: *Provided,* That the transaction shall forthwith be confirmed in the manner otherwise required by the regulations in this part.

[19 F.R. 2656, May 8, 1954]

§ 250.14 Samples, tests, and surveys.

(a) When deemed necessary or advisable, the supervisor is authorized to require that adequate tests or surveys be made in an acceptable manner without cost to the lessor to determine the reservoir energy; the presence, quantity, and quality of oil, gas, sulphur, other mineral deposits, or water; the amount and direction of deviation of any well from the vertical; or the formation, casing, tubing, or other pressures.

(b) The supervisor may, at the time of approval of any notice to drill or redrill any well, stipulate reasonable requirements for the taking of formation samples or cores to determine the identity and character of any information.

[19 F.R. 2657, May 8, 1954]

§ 250.15 Drilling and abandonment of wells.

The supervisor shall demand drilling in accordance with the terms of the lease and of the regulations in this part; and shall require plugging and abandonment, in accordance with such plan as may be approved or prescribed by him, of any well no longer used or useful, and upon failure to secure compliance with such requirement, perform the work at the expense of the lessee, expending available public funds, and submit such report as may be needed to furnish a basis for appropriate action to obtain reimbursement.

[19 F.R. 2657, May 8, 1954]

§ 250.16 Well potentials and permissible flow.

The supervisor is authorized to specify the time and method for determining the potential capacity of any well and to fix, after appropriate notice, the permissible production of any such well that may be produced when such action is necessary to prevent waste or to conform with such proration rules, schedules, or procedures as may be established by the Secretary.

[19 F.R. 2657, May 8, 1954]

§ 250.17 Well locations and spacing.

The supervisor is authorized to approve well locations and well spacing programs necessary for proper development giving consideration to such factors as the location of drilling platforms, the geological and reservoir characteristics of the field, the number of wells that can be economically drilled, the protection of correlative rights, and minimizing unreasonable interference with other uses of the Outer Continental Shelf area.

[34 F.R. 13545, Aug. 22, 1969]

§ 250.18 Rights of use and easement.

(a) In addition to the rights and privileges granted to a lessee under any lease issued or maintained under the act, the supervisor may grant such lessee, subject to such reasonable conditions as said supervisor may prescribe, the right of use or an easement to construct and maintain platforms, fixed structures, and artificial islands, and to use the same for carrying on operations, including drilling, directional drilling, producing, treating, handling, and storing production, and housing personnel engaged in operations, not only in connection with the lease on which the platform, structure, or island, is situated, but for the conduct of operations on any other lease, State or Federal.

(b) The supervisor may grant to a holder of a Federal or State lease the right of use or an easement to construct and maintain platforms, fixed structures, and artificial islands on areas of the outer Continental Shelf, near or adjacent to the leased area, and to use same for drilling directional well or wells to be bottomed under the leased area, and for producing and reworking such well or wells, and for handling, treating, and storing the production therefrom. Such rights of use or easement if on an area subject to any mineral lease issued or maintained under the act shall be granted only after the lessee under such lease has been notified and afforded an opportunity to voice objections thereto, and any such right shall be exercised only in such manner so as not to interfere unreasonably with operations of the lessee under such lease.

(c) In addition to the rights and privileges granted to a Federal lessee under any lease issued or maintained under the act, the supervisor upon proper application may grant to a holder of a Federal lease or State lease issued by a State which extends the same rights to holders of Federal leases, subject to such reasonable conditions as the supervisor may prescribe, the right of use or an easement to construct and maintain pipelines on areas of the Outer Continental Shelf which are constructed, owned, and maintained by the lessee and used for purposes such as (1) moving production to a central point for gathering, treating, storing, or measuring; (2) delivery of production to a point of sale; (3) delivery of production to a pipeline operated by a transportation company; or (4) moving fluids in connection with lease operations, such as for injection purposes. The supervisor is authorized to approve any reasonable offshore or onshore location as the central or delivery point. Rights of use or easement across areas covered by a mineral lease issued or maintained under the act shall be granted only after the lessee under such lease has been notified by the applicant and afforded a reasonable opportunity to express its views with respect thereto, and any such rights shall be exercised only in a manner so as not to interfere unreasonably with operations of the lessee under such lease. The foregoing right of use and easement shall not apply to pipelines used for transporting oil, gas, or other production after custody has been transferred to a purchaser or carrier as provided for in section 5(c) of the Outer Continental Shelf Lands Act and regulations in 43 CFR 2234.5–3.

(d) Once a right of use or easement has been exercised by the erection of platforms, fixed structures, artificial islands, or pipelines, the right shall continue only so long as they are maintained and are useful for the purpose specified therein, as determined by the supervisor, even beyond the termination of any lease on which they may be situated, and the rights of all subsequent lessees shall be subject to such rights of use and easement by prior lessees. Upon termination by the supervisor of the right of use and easement, the lessee shall remove or otherwise dispose of all platforms, fixed structures, artificial islands, pipelines, and other facilities and restore the premises to the satisfaction of the supervisor; provided, however, that pipelines may be abandoned in place so long as they do not constitute a navigational or other hazard as determined by the supervisor.

[19 FR 2657, May 8, 1954, as amended at 34 FR 13545, Aug. 22, 1969]

§ 250.19 Platforms and pipelines.

(a) The supervisor is authorized to approve the design, other features, and plan of installation of all platforms, fixed structures, and artificial islands as a condition of the granting of a right of use or easement under paragraphs (a) and (b) of § 250.18 or authorized under any lease issued or maintained under the act. The Supervisor is authorized to require that lessees maintaining existing platforms, fixed structures and artificial islands equipped with helicopter landing sites and refueling facilities provide the use of such facilities for helicopters employed by the Department of the Interior in inspection operations on the Outer Continental Shelf. The Supervisor is further authorized, in approving the design of any new platform, fixed structure, or artificial island which includes a helicopter landing site and refueling facilities to require that the lessee provide the use of such facilities for helicopters employed by the Department of the Interior in inspection operations on the Outer Continental Shelf. As determined by the Supervisor, the lessee shall be reimbursed for reasonable costs incurred in connection with the use of such facilities by helicopters employed by the Department.

(b) The supervisor is authorized to approve the design, other features, and plan of installation of all pipelines for which a right of use or easement has been granted under paragraph (c) of § 250.18 or authorized under any lease issued or maintained under the act, including those portions of such lines which extend onto or traverse areas other than the Outer Continental Shelf.

[34 F.R. 13545, Aug. 22, 1969, as amended at 29 FR 45015, Dec. 30, 1974]

§ 250.20 Rentals, royalties, and other payments.

The supervisor shall determine pursuant to the lease and regulations the rental and the amount or value of production accruing to the lessor as royalty, the loss through waste or failure to drill and produce protection wells on the lease, and the compensation due to the lessor as reimbursement for such loss.

[19 F.R. 2657, May 8, 1954. Redesignated at 34 F.R. 13545, Aug. 22, 1969]

REQUIREMENTS FOR LESSEES

§250.30 Lease terms, regulations, waste, damage and safety.

The lessee shall comply with the terms of applicable laws and regulations, the lease terms, OCS Orders and other written orders and rules of the supervisor, and with oral orders of the supervisor. All such oral orders shall be effective when issued, and are to be confirmed in writing as provided in § 250.11. The lessee shall take all necessary precautions to prevent damage to or waste of any natural resource or injury to life, or property, or the aquatic life of the seas.

[34 F.R. 13545, Aug. 22, 1969]

§ 250.31 Designation of operator.

In all cases where operations are not conducted by the record owner but are to be conducted under authority of an unapproved operating agreement, assignment, or other arrangement, a "designation of operator" shall be submitted to the supervisor, in a manner and form approved by him, prior to commencement of operations. Such designation will be accepted as authority of operator or his local representative to fulfill the obligations of the lessee and to sign any papers or reports required under the regulations in this part. All changes of address and any termination of the authority of the operator shall be immediately reported, in writing, to the supervisor or his representative. In case of such termination or of controversy between the lessee and the designated operator, the operator, if an possession of the lease, will be required to protect the interests of the lessor.

[19 F.R. 2657, May 8, 1954]

§ 250.32 Local agent.

When required by the supervisor, the lessee shall designate a representative empowered to receive notice and comply with orders of the supervisor issued pursuant to the regulations in this part.

§ 250.33 Drilling and producing obligations.

(a) The lessee shall diligently drill and produce such wells as are necessary to protect the lessor from loss by reason of production on other properties, or in lieu thereof, with the consent of the supervisor, shall pay a sum determined by the supervisor as adequate to compensate the lessor for failure to drill and produce any such well. In the event that the lease is not being maintained in force by other production of oil or gas in paying quantities or by other approved drilling or reworking operations, such payments shall be considered as the equivalent of production in paying quantities for all purposes of the lease.

(b) The lessee shall promptly drill and produce such other wells as the supervisor may reasonably require in order that the lease may be properly and timely developed and produced in accordance with good operating practices.

[19 F.R. 2657, May 8, 1954]

§ 250.34 Drilling and development programs.

(a) *Exploratory drilling plan.* Prior to commencing each exploratory drilling program on a lease, including the construction of platforms, the lessee shall submit a plan to the supervisor for approval. Each plan for the leased area shall include (1) a description of drilling vessels, platforms, or other structures showing the location, the design, and the major features thereof, including features pertaining to pollution prevention and control; (2) the general location of each well including surface and projected bottom hole location for directionally drilled wells; (3) structural interpretations based on available geological and geophysical data; and (4) such other pertinent data as the supervisor may prescribe.

(b) *Development plan.* Prior to commencing each development program on a lease, the lessee shall submit a plan to the supervisor for approval. The plan shall include all information specified in paragraph (a) of this section in detail.

(d) *Modifications.* The lessee shall submit: (1) All requests for modifications an exploratory or development plan, the lessee shall submit an Application for Permit to Drill (Form 9-331C) to the supervisor for approval. The application shall include the integrated blowout prevention, mud, casing, and cementing program for the well, and shall meet the requirements specified in § 250.41(a), and contain the information specified in § 250.91(a), and shall conform with the approved exploratory or development plan.

(d) *Modifications.* The lessee shall submit: (1) All requests for modifications of an approved exploratory or development plan in writing to the supervisor for approval; and (2) all notices of changes to plans set forth in the approved Application for Permit to Drill on Sundry Notices and Reports on Wells (Form 9-331), except that these requirements shall not relieve the lessee from taking appropriate action to prevent or abate damage, waste, or pollution of any natural resource or injury to life or property.

[34 F.R. 13546, Aug. 22, 1969]

§ 250.35 Extension of leases by drilling or well reworking.

(a) The Secretary shall be deemed to have approved, within the meaning of section 8(b)(2) of the Outer Continental Shelf Lands Act, drilling or well reworking operations, conducted on the leased area in the following instances:

(1) If, after discovery of oil or gas in paying quantities has been made on the leasehold, and within 90 days prior to expiration of the five-year term or any extension thereof, or thereafter, the production thereof shall cease at any time, or from time to time, from any cause and production is restored or drilling or well reworking operations are commenced within 90 days thereafter, and such drilling or well reworking operations (whether on the same or different wells) are prosecuted diligently until production is restored in paying quantities.

(2) If, within 90 days prior to expiration of the five-year term or any extension thereof, or thereafter, at any time, or from time to time, lessee is engaged in drilling or well working operations on the leasehold and there is no well on the leasehold capable of producing in paying quantities and the lessee diligently prosecutes such operations (whether on the same or different wells) with no cessation of more than 90 days.

(b) The Secretary may approve such other operations for drilling or reworking upon application of lessee.

(c) Nothing in this section obviates the necessity of obtaining the Supervisor's approval of a plan or notice of intention to drill or of complying with the other provisions of this part.

[24 F.R. 9527, Nov. 28, 1959. Redesignated at 34 F.R. 13546, Aug. 22, 1969]

§ 250.36 Subsequent well operations.

Prior to commencing operations not previously approved, such as deepening, plugging-back, repairing (other than work incidental to ordinary well operations), acidizing or stimulating production by other methods, perforating, sidetracking, squeezing with mud or cement, abandoning, and any similar operation which will alter the condition of a well, the lessee shall submit an application or notice as specified in § 250.91 and 250.92 to the supervisor for approval. This requirement shall not relieve the lessee from taking appropriate action to prevent or abate damage or waste of any natural resource, or injury to life or property.

[34 F.R. 13546, Aug. 22, 1969]

§ 250.37 Well designations.

The lessee shall mark promptly each drilling platform or structure in a conspicuous place, showing his name or the names of the operator, the serial number of the lease, the identification of the wells, and shall take all necessary means and precautions to preserve these markings.

[19 F.R. 2658, May 8, 1954. Redesignated at 34 F.R. 13546, Aug. 22, 1969]

§ 250.38 Well records.

(a) The lessee shall keep for each well at his field headquarters or at other locations conveniently available to the supervisor, accurate and complete records of all well operations including production. drilling, logging, directional well surveys, casing, perforating, safety devices, redrilling deepening, repairing, cementing, alterations to casing, plugging, and abandoning. The records shall contain a description of any unusual malfunction, condition or problem; all the formations penetrated; the content and character of oil, gas, and other mineral deposits, and water in each formation; the kind, weight, size, grade, and setting depth of casing; and any other pertinent information.

(b) Upon request of the supervisor, the lessee shall immediately transmit copies of records of any of the well operations specified in paragraph (a) of this section; however, in any event the lessee shall, within 30 days after completion of any well, transmit to the supervisor copies of the records of all operations (except logging) in duplicate on or attached to Form 9-330, except that when operations are suspended the lessee shall transmit copies of the records of all operations conducted thereon to the supervisor within 30 days after the suspension; and within 30 days after the suspension or completion of any further operations, including those described in § 250.92, the lessee shall transmit to the supervisor copies of the records of such operations in duplicate on or attached to Form 9-330 or Form 9-331, as appropriate.

(c) Upon request by the supervisor, the lessee shall submit paleontological reports identifying microscopic fossils by depth (not the resulting interpretations based upon such identifications) unless washed well samples normally maintained by the lessee for paleontological determinations are made available to the supervisor for inspection.

(d) Upon request of the supervisor, the lessee shall immediately transmit copies (field or final prints of individual runs) of logs or charts of electrical, radioactive, sonic, and other well logging operations and directional well surveys. Composite logs of multiple runs and directional well surveys shall be transmitted to the supervisor in duplicate as soon as available, but not later than 30 days after completion of such operations for each well.

(e) Upon request of and in the manner and form prescribed by the supervisor, the lessee shall furnish copies of the daily drilling report and a plat showing the location, designation, and status of all wells on the leased lands.

(f) Upon request of the supervisor, the lessee shall furnish legible, exact copies of service company reports on cementing, perforating, acidizing, analyses of cores, or other similar services.

(g) The lessee shall submit any other reports and records of operations when required and in the manner and form prescribed by the supervisor.

[34 F.R. 13546, Aug. 22, 1969]

§ 250.39 Samples, tests, and surveys.

(a) The lessee, when required by the supervisor, shall make adequate tests or surveys in an acceptable manner, without cost to the lessor, to determine the reservoir energy; the presence, quantity, and quality of oil, gas, sulphur, other mineral deposits, or water; the amount and direction of deviation of any well from the vertical; or the formation, casing, tubing, or other pressures.

(b) The lessee shall take such formation samples or cores to determine the identity and character of any formation in accordance with reasonable requirements of the supervisor prescribed at the time of approval of the notice to drill or redrill any well.

[19 F.R. 2658, May 8, 1954. Redesignated at 34 F.R. 13546, Aug. 22, 1969]

§ 250.40 Directional survey.

(a) An angular deviation and directional survey shall be made of the finished hole of each well directionally drilled.

(b) The supervisor, at the request of an offset lessee made prior to completion of a well, may require a lessee of an adjoining lease to make or furnish a directional survey of any hole, at the risk and expense of the offset lessee making such request. A copy of such directional survey shall be furnished to the supervisor and the offset lessee. If it is determined that such well is closer to the line of the offset lease than one-half (½) the required distance from such line fixed by an approved spacing program or by special field rules, the risk and expense of making such directional survey shall be borne by the offending lessee; and, unless and until the hole is promptly straightened to correct the offense, the supervisor may reduce the allowable production from the well to prevent its draining unduly the offset leased area. Neither the imposition of any penalty or of the costs of such survey upon the offending lessee nor the reduction of the allowable production from the well is intended to prejudice any other remedy which the affected parties may have.

[19 F.R. 2658, May 8, 1954. Redesignated at 34 F.R. 13546, Aug. 22, 1969]

§ 250.41 Control of wells.

(a) *Drilling wells.* The lessee shall take all necessary precautions to keep all wells under control at all times, shall utilize only personnel trained and competent to drill and operate such wells, and shall utilize and maintain materials and high-pressure fittings and equipment necessary to insure the safety of operating conditions and procedures. The design of the integrated casing, cementing, drilling mud, and blowout prevention program shall be based upon sound engineering principles, and must take into account the depths at which various fluid or mineral-bearing formations are expected to be penetrated, and the formation fracture gradients and pressures expected to be encountered, and other pertinent geologic and engineering data and information about the area.

(1) *Well casing and cementing.* The lessee shall case and cement all wells with a sufficient number of strings of casing in a manner necessary to: (i) Prevent release of fluids from any stratum through the well bore (directly or indirectly) into the sea; (ii) prevent communication between separate hydrocarbon-bearing strata (except such strata approved for commingling) and between hydrocarbon and water-bearing strata; (iii) prevent contamination of fresh water strata, gas, or water; (iv) support unconsolidated sediments; and (v) othewise provide a means of control of the formation pressures and fluids. The lessee shall install casing necessary to withstand collapse, bursting, tensile, and other stresses and the casing shall be cemented in a manner which will anchor and support the casing. Safety factors in casing program design shall be of sufficient magnitude to provide optimum well control while drilling and to assure safe operations for the life of the well. When directed by the supervisor, the lessee shall install structural or drive casing to provide hole stability for the initial drilling operation. A conductor string of casing (the first string run other than any structural or drive casing) must be cemented with a volume of cement sufficient to circulate back to the sea floor; however, if authorized by OCS Order or the supervisor, cement may be washed out or displaced to a specified depth below the sea floor to facilitate casing removal upon well abandonment. All subsequent strings must be securely cemented.

(2) *Drilling mud.* The lessee shall maintain readily accessible for use quantities of mud sufficient to insure well control. The testing procedures, characteristics, and use of drilling mud and the conduct of related drilling procedures

shall be such as are necessary to prevent blowouts. Mud testing equipment and mud volume measuring devices shall be maintained at all times, and mud tests shall be performed frequently and recorded on the driller's log as prescribed by the supervisor.

(3) *Blowout prevention equipment.* The lessee shall install, use, and test blowout preventers and related well-control equipment in a manner necessary to prevent blowouts. Such installation, use and testing must meet the standards or requirements prescribed by the supervisor; provided, however, in no event shall the lessee conduct drilling below the conductor string of casing until the installation of at least one remotely controlled blowout preventer and equipment for circulating drilling fluids to the drilling structure or vessel. Blowout preventers and related well-control equipment shall be pressure tested when installed, after each string of casing is cemented, and at such other times as prescribed by the supervisor. Blowout preventers shall be activated frequently to test for proper functioning as prescribed by the supervisor. All blowout-preventer tests shall be recorded on the drillers log.

(b) *Completed wells.* In the conduct of all its operations, the lessee shall take all steps necessary to prevent blowouts, and the lessee shall immediately take whatever action is required to bring under control any well over which control has been lost. The lessee shall: (1) In wells capable of flowing oil or gas, when required by the supervisor, install and maintain in operating condition storm chokes or similar subsurface safety devices; (2) for producing wells not capable of flowing oil or gas, install and maintain surface safety valves with automatic shutdown controls; and (3) periodically test or inspect such devices or equipment as prescribed by the supervisor.

[34 F.R. 13546, Aug. 22, 1969]

§ 250.42 Emulsion and dehydration.

(a) The lessee shall complete and maintain all oil wells in such mechanical condition and operate them in such manner as to prevent, so far as possible, the formation of emulsion and basic sediment.

(b) The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment.

[19 F.R. 2658, May 8, 1954. Redesignated at 34 F.R. 13546, Aug. 22, 1969]

§ 250.43 Pollution and waste disposal.

(a) The lessee shall not pollute land or water or damage the aquatic life of the sea or allow extraneous matter to enter and damage any mineral- or water-bearing formation. The lessee shall dispose of all liquid and nonliquid waste materials as prescribed by the supervisor. All spills or leakage of oil or waste materials shall be recorded by the lessee and, upon request of the supervisor, shall be reported to him. All spills or leakage of a substantial size or quantity, as defined by the supervisor, and those of any size or quantity which cannot be immediately controlled also shall be reported by the lessee without delay to the supervisor and to the Coast Guard and the Regional Director of the Federal Water Pollution Control Administration. All spills or leakage of oil or waste materials of a size or quantity specified by the designee under the pollution contingency plan shall also be reported by the lessee without delay to such designee.

(b) If the waters of the sea are polluted by the drilling or production operations conducted by or on behalf of the lessee, and such pollution damages or threatens to damage aquatic life, wildlife, or public or private property, the control and total removal of the pollutant, wheresoever found, proximately resulting therefrom shall be at the expense of the lessee. Upon failure of the lessee to control and remove the pollutant the supervisor, in cooperation with other appropriate agencies of the Federal, State and local governments, or in cooperation with the lessee, or both, shall have the right to accomplish the control and removal of the pollutant in accordance with any established contingency plan for combating oil spills or by other means at the cost of the lessee. Such action shall not relieve the lessee of any responsibility as provided herein.

(c) The lessee's liability to third parties, other than for cleaning up the pollutant in accordance with paragraph (b) of this section shall be governed by applicable law.

[34 F.R. 13547, Aug. 22, 1969]

§ 250.44 Well abandonment.

The lessee shall promptly plug and abandon any well on the leased land that is not used or useful, but no productive well shall be abandoned until its lack of capacity for further profitable production of oil, gas, or sulphur has been demonstrated to the satisfaction of the supervisor. Before abandoning a producible well, the lessee shall submit to the supervisor a statement of reasons for abandonment and his detailed plans for carrying on the necessary work. A producible well may be abandoned only after receipt of written approval by the supervisor. No well shall be plugged and abandoned until the manner and method of plugging shall be approved or prescribed by the supervisor. Equipment shall be removed, and premises at the well-site shall be properly conditioned immediately after plugging operations are completed on any well when directed by the supervisor. Drilling equipment shall not be removed from any suspended drilling well without taking adequate measures to protect the natural resources.

[19 F.R. 2658, May 8, 1954. Redesignated at 34 F.R. 13546, Aug. 22, 1969]

§ 250.45 Accidents, fires, and malfunctions.

In the conduct of all its operations, the lessee shall take all steps necessary to prevent accidents and fires, and the lessee shall immediately notify the supervisor of all serious accidents and all fires on the lease, and shall submit in writing a full report thereon within 10 days. The lessee shall notify the supervisor within 24 hours of any other unusual condition, problem, or malfunction.

[34 F.R. 13547, Aug. 22, 1969]

§ 250.46 Workmanlike operations.

The lessee shall perform all operations in a safe and workmanlike manner and shall maintain equipment for the protection of the lease and its improvements, for the health and safety of all persons, and for the preservation and conservation of the property and the environment. The lessee shall take all necessary precautions to prevent and shall immediately remove any hazardous oil and gas accumulations or other health, safety or fire hazards.

[34 F.R. 13547, Aug. 22, 1969]

§ 250.47 Sales contracts.

The lessee shall file with the supervisor within 30 days after the effective date thereof copies of all contracts for the disposal of lease products. Nothing in any such contract shall be construed or accepted as modifying any of the provisions of the lease, including provisions relating to gas waste, taking royalty in kind, and the method of computing royalties due as based on a minimum valuation and in accordance with the regulations applicable to the lands covered by the contract.

[34 F.R. 13547, Aug. 22, 1969]

§ 250.48 Division orders.

The lessee shall file with the supervisor within 30 days after the effective date thereof copies of division orders or other instruments granting to transportation agencies or purchasers authority to receive products from leased lands. The supervisor may, upon request, approve such orders or other instruments subject to such conditions as he shall prescribe.

[19 F.R. 2659, May 8, 1954, as amended at 34 F.R. 13547, Aug. 22, 1969]

§ 250.49 Royalty and rental payments.

The lessee shall pay all rentals when due and all pay in value or deliver in production all royalties in the amounts determined by the supervisor as due under the terms of the lease. Payments of rentals and royalties in value shall be by check or draft on a solvent bank, or by money order, drawn to the order of the United States Geological Survey.

[21 F.R. 4668, June 27, 1956. Redesignated at 34 F.R. 13546, Aug. 22, 1969]

§ 250.50 Unit plans, pooling, and drilling agreements.

Section 5(a)(1) of the act authorizes the Secretary in the interest of conservation to provide for unitization, pooling and drilling agreements. Such agreements may be initiated by lessees or where in the interest of conservation they are deemed necessary they may be required by the Director.

[29 F.R. 4563, Mar. 31, 1964, as amended at 34 F.R. 13547, Aug. 22, 1969]

§ 250.51 Application for approval of unit plan.

The procedure for obtaining the approval of a unit plan of development is contained in 30 CFR Part 226. "Unit or Cooperative Agreements". All applications to unitize and all documents incident thereto shall be filed in the office of the oil and gas supervisor, Geological Survey, for the geographic area in which the unit areas is situated.

[29 F.R. 4563, Mar. 31, 1964. Redesignated at 34 F.R. 13547, Aug. 22, 1969, as amended at 38 F.R. 10001, Apr. 23, 1973]

§ 250.52 Pooling or drilling agreements.

(a) With the approval of the supervisor, pooling or drilling agreements may be made between lessees for the purposes of (1) utilizing a common drilling platform to develop adjacent or adjoining leases; (2) permitting operators or pipeline companies to enter into contracts involving a number of leases sufficient to justify operations on a large scale for the discovery, development, production or transportation of oil and gas, sulphur, or other minerals, and to finance the same; or (3) for other purposes in the interest of conservation.

(b) A contract submitted for approval under these provisions should be filed with the oil and gas supervisor, together with enough copies to permit retention of 5 copies by the Department after approval. Complete details must be furnished in order that the supervisor may have facts upon which to make a definite determination and prescribe the conditions on which the contract is approved.

[29 F.R. 4563, Mar. 31, 1964, as amended at 34 F.R. 13547, Aug. 22, 1969]

§ 250.53 Subsurface storage of oil or gas.

(a) In order to avoid waste or to promote conservation of natural resources, and when it can be shown that no undue interference with operations under existing leases will result, the Director, upon application by the interested parties, may authorize the subsurface storage of oil or gas in the lands of the outer Continental Shelf, whether or not produced from the outer Continental Shelf. Such authorization will provide for the payment of such storage fee or rental on the stored oil or gas as may be determined adequate in each case, or, in lieu thereof, for a royalty other than that prescribed in any lease of the area involved when such stored oil or gas is produced in conjunction with oil or gas not previously produced. Any lease of an area used for the storage of oil or gas shall not be deemed to expire during the period of such storage and so long thereafter as oil or gas not previously produced is produced in paying quantities, or drilling or well reworking operations as approved by the Secretary are conducted thereon.

(b) Applications for subsurface storage shall be filed in triplicate with the oil and gas supervisor and shall disclose the ownership of the lands or interests in the lands involved, the parties in interest, including lessees of other mineral interests, the storage fee, rental, or royalty offered to be paid for such storage and all essential information showing the necessity for such storage. Enough copies of the final agreement signed by the parties in interest shall be submitted for the approval of the Director to permit retention of 5 copies by the Department after approval.

[29 F.R. 4563, Mar. 31, 1964, as amended at 34 F.R. 13547, Aug. 22, 1969]

MEASUREMENT OF PRODUCTION AND COMPUTATION OF ROYALTIES

§ 250.60 Measurement of oil.

The lessee shall gage and measure all production in accordance with methods approved by the supervisor. The lessee shall provide tanks suitable for measuring accurately the crude oil produced from the lease (exact copies of 100 percent capacity tank tables to be furnished to the supervisor) or may arrange with the supervisor for other acceptable methods of measuring, storing, and recording production. The quantity and quality of all production shall be determined in accordance with the standard practices, procedures, and specifications generally used by the industry.

[19 F.R. 2659, May 8, 1954 as amended at 34 F.R. 13547, Aug. 22, 1969]

§ 250.61 Measurement of gas.

The lessee shall measure all gas production in accordance with methods approved by the supervisor, and the measured volumes shall be adjusted to the standard pressure base of 10 ounces above the atmospheric pressure of 14.4

pounds per square inch, a standard temperature of 60° Fahrenheit, and for deviation from Boyle's law. If gas is being disposed of at a different pressure base, the supervisor may require that gas volumes be adjusted to conform to such base.

§ 250.62 Determination of content of gas.

The content of gas delivered to an extraction plant treating gas from the lease shall be determined periodically by field tests, as required by the supervisor, to be made at the place and by the methods approved by him and under his supervision.

[19 F.R. 2659, May 8, 1954]

§ 250.63 Quantity basis for substances extracted from gas.

(a) The primary quantity basis for computing monthly royalties on casinghead or natural gasoline, butane, propane, or other substances (hereinafter called substances in this section) extracted from gas is the monthly net output of the plant at which the substances are manufactured, "net output" being defined as the quantity of each substance that the plant produces for sale.

(b) If the net output of a plant is derived from the gas obtained from only one lease, the quantity of substances on which computations of royalty for the lease is based is the net output of the plant.

(c) If the net plant output of a substance is derived from gas obtained from several leases producing gas of uniform content of such substance, the proportion of net output of the substance allocable to each lease as a basis for computing royalty will be determined by dividing the amount of gas delivered to the plant from each lease by the total amount of gas delivered from all leases.

(d) If the net plant output of a substance is derived from gas obtained from several leases producing gas of diverse content of such substance, the proportion of net output of the substance allocable to each lease as a basis for computing royalty will be determined by multiplying the amount of gas delivered to the plant from the lease by the substance content of the gas and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant.

[19 F.R. 2659, May 8, 1954]

§ 250.64 Value basis for computing royalties.

The value of production, for the purpose of computing royalty, shall be the estimated reasonable value of the product as determined by the supervisor, due consideration being given to the highest price paid for a part or for a majority of production of like quality in the same field or area, to the price received by the lessee, to posted prices, and to other relevant matters. Under no circumstances shall the value of production of any of said substances for the purposes of computing royalty be deemed to be less than the gross proceeds accruing to the lessee from the sale thereof or less than the value computed on such reasonable unit value as shall have been determined by the Secretary. In the absence of good reason to the contrary, value computed on the basis of the highest price paid or offered at the time of production in a fair and open market for the major portion of like-quality products produced and sold from the field or area where the leased lands are situated will be considered to be a reasonable value.

[19 F.R. 2659, May 8, 1954]

§ 250.65 Royalty on oil.

(a) The royalty on crude oil, including condensates separated from gas without the necessity of a manufacturing process, shall be the percentage of the value or amount of the crude oil produced from the leased lands established by law, regulation, or the provisions of the lease. No deduction shall be made for actual or theoretical transportation losses.

(b) Royalty shall be based on production removed from the lease except that, when conditions so warrant, the supervisor may require such royalty to be based on actual monthly production. Evidence of all shipments shall be filed with the supervisor within five days (or such longer period as the supervisor may approve) after the oil has been run by pipeline or by other means of transportation. Such evidence shall be signed by representatives of the lessee and of the purchaser or the transporter who have witnessed the measurements reported, and the determinations of gravity, temperature, and the percentage of impurities contained in the oil shall be shown.

[19 F.R. 2659, May 8, 1954, as amended at 34 F.R. 13547, Aug. 22, 1969]

§ 250.66 Royalty on unprocessed gas.

If gas, either gas-well gas or casing-head gas, is sold without processing for the recovery of constituent products, the royalty thereon shall be the percentage established by the terms of the lease of the value or amount of the gas produced.

[19 F.R. 2659, May 8, 1954]

§ 250.67 Royalty on processed gas and constituent products.

(a) If gas is processed for the recovery of constituent products, a royalty as provided in the lease will accrue on the value of amount of:

(1) All residue gas remaining after processing; and

(2) All natural gasoline, butane, propane, or other products extracted therefrom, subject to deduction of such portion thereof as the supervisor determines to be a reasonable allowance for the cost of processing based upon regional plant practices and costs and other pertinent factors; provided, however, that such reasonable allowance shall not exceed two-thirds of the products extracted unless the Director determines that a greater allowance is in the interest of conservation.

(b) Under no circumstances shall the amount of royalty on the residue gas and extracted products be less than the amount which the supervisor determines would be payable if the gas had been sold without processing.

(c) In determining the value of natural gasoline, the volume of such gasoline shall be adjusted to a standard by a method approved by the supervisor when necessary to adjust volumetric differences between natural gasolines of various specifications.

(d) No allowance shall be made for boosting residue gas or other expenses incidental to marketing.

(e) The lessee, with the approval of the supervisor, may establish a gross value per unit of 1,000 cubic feet of gas on the lease or at the wellhead for the purpose of computing royalty on gas processed for the recovery of constituent products, provided that the royalty shall not be less than that which would accrue by computing royalties in accordance with the provisions of paragraphs (a) through (d) of this section.

[34 F.R. 13547, Aug. 22, 1969]

§ 250.63 Commingling production.

Subject to such conditions as he may prescribe for measurement and allocation of production, the supervisor may authorize the lessee to move production from the lease to a central point for purposes of treating, measuring, and storing, and in moving such production, the lessee may commingle the production from different wells, leases, pools and fields, and with production of other operators. The central point may be on shore or at any other convenient place selected by lessee.

[19 F.R. 2660, May 8, 1954]

§ 250.69 Measurement of sulphur.

The measurement of sulphur for the purpose of computing royalty shall be on such basis and shall conform to such standards as the supervisor may approve.

[19 F.R. 2660, May 8, 1954]

PROCEDURE IN CASE OF DEFAULT BY LESSEE

§ 250.80 Default.

Whenever the owner of a lease fails to comply with the provisions of the regulations in this part, the supervisor is authorized to give 30-day notice of such default by registered letter to the lessee at his record post office address as provided in section 5(b) (1) of the act and to recommend to the Secretary through the Director, lease cancellation pursuant to section 5(b) (1) and (2) of the act, appropriate action under the penalty provisions of section 5(a) (2) of the act, or the exercise of such other legal or equitable remedy as the lessor may have.

[19 F.R. 2660, May 8, 1954]

§ 250.81 Appeals.

Orders or decisions issued under the regulations in this part may be appealed as provided in part 290 of this chapter. Compliance with any such order or decision shall not be suspended by reason of any appeal having been taken unless such suspension is authorized in writing by the Director or the Board of Land

Appeals (depending upon the official before whom the appeal is pending) and then only upon a determination that such suspension will not be detrimental to the lessor or upon the submission and acceptance of a bond deemed adequate to indemnify the lessor from loss or damage.

[38 F.R. 10001, Apr. 23, 1973]

§ 250.82 Judicial review.

Nothing contained in this part shall be construed to prevent any interested party from seeking judicial review as authorized by law.

[19 F.R. 2660, May 8, 1954]

REPORTS TO BE MADE BY ALL LESSEES (INCLUDING OPERATORS)

§ 250.90 General requirements.

Information required to be submitted in accordance with the regulations in this part shall be furnished in the manner and form prescribed in the regulations in this part or as directed by the supervisor. Copies of forms can be obtained only from the supervisor and must be filled out completely and filed punctually with that official.

[19 F.R. 2660, May 8, 1954]

§ 250.91 Application for permit to drill, deepen, or plug back.

Applications for permits to drill, deepen, or plug back must be filed in triplicate on Form 9–331C. Prior to commencing such operations approval in writing must be received from the supervisor.

(a) *Application for permit to drill.* (1) The application must give the surface location and projected bottom-hole location in feet from the lease boundaries; elevation of the derrick floor; water depth; depth to which the well is proposed to be drilled; estimated depths to the top of significant markers; depths at which water, oil, gas, and mineral deposits are expected; the proposed blowout prevention and casing program, including the size, weight, grade, and setting depth of casing, and the quantity of cement to be used, together with all other information specified on Form 9–331C. Information also shall be furnished relative to the proposed plan for drilling other wells from the same platform, for coring at specified depths, and for electrical and other logging, together with any other information required by the supervisor.

(2) At least two copies of the application shall be accompanied by: (i) A certified plat drawn to a scale of 2,000 feet to the inch, showing surface and subsurface location of the well to be drilled and all wells theretofore drilled in the vicinity for which information is available, and (ii) information specified in § 250.34 to the extent not included in the application or previously furnished (reference must be made thereto).

(b) *Application for permit to deepen or plug back.* The application must describe fully: (1) The present status of the well including the production string or last string of casing, well depth, present productive zones and productive capability, and other pertinent matters; and (2) the details of the proposed work and the necessity therefor.

[34 F.R. 13548, Aug. 22, 1969]

§ 250.92 Sundry notices and reports on wells.

All notices of intention to fracture treat, acidize, repair, multiple complete, abandon, change plans, and for other similar purposes, and all subsequent reports pertaining to such operations shall be submitted on Form 9–331 in triplicate in accordance with § 250.33(b). Prior to commencing such operations approval must be received from the supervisor in writing.

(a) *Notice of intention to change the condition of a well.* Form 9–331 shall contain a detailed statement of the proposed work for repairing (other than work incidental to ordinary well operation), acidizing or stimulating production by other methods, perforating, side-tracking, squeezing with mud or cement, or commencing any operations that will materially change the approved program for drilling a well or alter the condition of a completed well other than those operations covered by § 250.91.

(b) *Subsequent report of changing the condition of a well.* Form 9–331 shall contain a detailed report of all work done and the results obtained. The report shall set forth the amount and rate of production of oil, gas, and water before and after the work was completed and shall include a complete statement of the dates on which the work was accomplished and the methods employed.

(c) *Notice of intention to abandon well.* Form 9-331 shall contain a detailed statement of the proposed work for abandonment of any well, including a drilling well, a depleted producing well, an injection well, or a dry hole. The statement as to a producible well shall set forth the reasons for abandonment and the amount and date of last production and, as to all wells, shall describe the proposed work, including kind, location, and length of plus (by depths), and plans for mudding, cementing, shooting, testing, removing casing, and other pertinent information.

(d) *Subsequet report of abandonment.* Form 9-331 shall contain a detailed report of the manner in which the abandonment or plugging work was accomplished, including the nature and quantities of materials used in plugging and the location and extent (by depths) of casing left in the well; and the volume of mud fluid used. If an attempt was made to part any casing, a description of the methods used and results obtained must be included.

[34 F.R. 13548, Aug. 22, 1969]

§ 250.93 Monthly report of operations.

A separate report of operations for each lease must be made on Form 9-152 for each calendar month, beginning with the month in which drilling operations are initiated, and must be filed in duplicate with the supervisor on or before the 20th day of the succeeding month, unless an extension of time for the filing of such report is granted by the supervisor. The report on this form shall disclose accurately all operations conducted on each well during each month, the status of operations on the last day of the month, and a general summary of the status of operations on the leased lands, and the report must be submitted each month until the lease is terminated or until omission of the report is authorized by the supervisor. It is particularly necessary that the report shall show for each calendar month:

(a) Each well listed separately by number and its location shown if possible.

(b) The number of days each well produced, whether oil or gas, and the number of days each input well was in operation.

(c) The quantity of oil, gas, and water produced; the total amount of gasoline and other lease products recovered: and other required information. When oil and gas, or oil, gas, and gasoline, or other hydrocarbons are concurrently produced from the same lease, separate reports on this form should be submitted for oil and gas and gasoline, unless otherwise authorized or directed by the supervisor.

(d) The depth of each active or suspended well; the name, character, and depth of each formation drilled during the month; the date each such depth was reached: the date and reason for every shutdown; the names and depths of important formation changes and contents of formations; the amount and size of any casing run since last report; the dates and results of any tests such as production, water shutoff, or gasoline content; and any other noteworthy information on operations not specifically provided for in the form.

(e) If no runs or sales were made during the calendar month, the report must so state.

[19 F.R. 2661, May 8, 1954]

§ 250.94 Statement of oil and gas runs and royalties.

When directed by the supervisor, a monthly report shall be made by the lessee on Form 9-153, showing each run of oil; all sales of gas, gasoline, and other lease products; and the royalty accruing therefrom to the lessor.

[19 F.R. 2661, May 8, 1954, as amended at 34 F.R. 13548, Aug. 22, 1969]

§ 250.95 Well completion or recompletion report and log.

All reports and logs of well completions or recompletions shall be submitted on or attached to Form 9-330 in duplicate in accordance with § 250.38(b). The form shall contain a complete and accurate log and report of all operations conducted on the well as specified on the form. Duplicate copies of logs that may have been compiled for geologic information from cores or formation samples shall be filed in addition to the regular log. Geologic markers and all important zones of porosity and contents thereof; cored intervals; and all drill-stem tests, including depth interval tested, cushion used, time tool open, flowing and shut-in pressures, and recoveries shall be shown as provided therefor on Form 9-330 or on attachments thereto. If not previously furnished, duplicate copies of composites of multiple runs of all well bore surveys, including electric, radioactive, sonic and other logs, temperature surveys, and directional surveys shall be attached. (Such copies are in addition to field prints filed pursuant to § 250.38(d).)

[34 F.R. 13548, Aug. 22, 1969]

§ 250.96 Special forms or reports.

When special forms or reports other than those referred to in the regulations in this part may be necessary, instructions for the filing of such forms or reports will be given by the supervisor.

[19 F.R. 2661, May 8, 1954. Redesignated at 34 F.R. 13548, Aug. 22, 1969]

§ 250.97 Public inspection of records.

Geological and geophysical interpretations, maps, and data required to be submitted under this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect or until such time as the supervisor determines that release of such information is required and necessary for the proper development of the field or area.

[34 F.R. 13548, Aug. 22, 1969]

MINERAL LEASES AFFECTED BY SECTION 6 OF OUTER CONTINENTAL SHELF LANDS ACT

§ 250.100 Effect of regulations on provisions of lease.

(a) As contemplated by section 6(b) of the act, the regulations in this part will supersede the provisions of any lease which is determined to meet the requirements of section 6(a) of the act, to the extent that they cover the same subject matter, with the following exceptions: The provisions of a lease with respect to the area covered by the lease, the minerals covered by the lease, the rentals payable under the lease, the royalties payable under the lease (subject to the provisions of section 6 (a) (8) and 6 (a) (9) of the act), and the term of the lease (subject to the provisions of section 6 (a) (10) of the act and, as to sulphur, subject to the provisions of section 6(b)(2) of the act) shall continue in effect and, in the event of any conflict or inconsistency, shall take precedence over the regulations in this part.

(b) A lease that meets the requirements of section 6 (a) of the act shall also be subject to the mineral leasing regulations applicable to the outer Continental Shelf, as well as the regulations relating to geophysical and geological exploratory operations and to pipeline rights-of-way in the outer Continental Shelf, to the extent that those regulations are not contrary to or inconsistent with the provisions of the lease relating to the area covered, the minerals covered, the rentals payable, the royalties payable, and the terms of the lease.

[19 F.R. 2661, May 8, 1954]

NOTE: The record keeping or reporting requirements of this part have been approved by the Bureau of the Budget in accordance with the Federal Reports Act of 1942.

[From the Federal Register, vol. 40, No. 78, Apr. 22, 1975]

APPENDIX XVI. PROPOSED RULES PERTAINING TO GEOLOGICAL AND GEOPHYSICAL EXPLORATION OF THE OUTER CONTINENTAL SHELF

(Part 250. Title 30 of the Code of Federal Regulations)

GEOLOGICAL SURVEY

[30 CFR Parts 250, 251]

OUTER CONTINENTAL SHELF

OIL, GAS AND SULPHUR OPERATIONS; GEOLOGICAL AND GEOPHYSICAL EXPLORATIONS

Notice is hereby given that, pursuant to the authority vested in the Secretary of the Interior by the Outer Continental Shelf Lands Act of August 7, 1953 (67 Stat. 462; 43 U.S.C. 1331–1343), it is proposed to amend 30 CFR 250.97 and to add Part 251 to Title 30, Code of Federal Regulations.

The purpose of the amendment of 30 CFR 250.97 is to specify a definite time when geological and geophysical interpretations, maps and data pertaining to leased lands will be made available for public inspection. The purpose of Part

251 is to prescribe policies, procedures, and requirements for conducting geological and geophysical explorations of the Outer Continental Shelf.

It is also proposed that when Part 251 is adopted, all existing authorizations to conduct geological and geophysical explorations of the Outer Continental Shelf be revoked as follows:

(1) Notice dated September 17, 1953, Outer Continental Shelf, Geological and Geophysical Explorations (Texas) (18 FR 5667 and footnote 1).

(2) Notice dated March 23, 1954, Outer Continental Shelf, Geological and Geophysical Explorations (Louisiana) (19 FR 1730).

(3) Notice dated March 31, 1955, Outer Continental Shelf, Geological and Geophysical Explorations (California) (20 FR 2023).

(4) Notice dated March 27, 1956, Outer Continental Shelf, Geological and Geophysical Exploration (Florida) (21 FR 2129).

(5) Notice dated August 25, 1958, Outer Continental Shelf, Geological and Geophysical Explorations (Alabama) (23 FR 6760).

(6) Notice dated August 5, 1960, Outer Continental Shelf, Geological and Geophysical Explorations (Georgia) (25 FR 7811).

(7) Notice dated September 6, 1960, Outer Continental Shelf, Geological and Geophysical Explorations (Atlantic Coast Area) (25 FR 8759).

(8) Notice dated July 28, 1961, Outer Continental Shelf, Geological and Geophysical Explorations (Pacific Coast Area off Oregon and Washington) (26 FR 6874).

(9) Notice dated March 7, 1964, Outer Continental Shelf, Geological and Geophysical Exploration (Alaska) (29 FR 3369).

(10) Memorandum dated May 14, 1965, from the Director, Geological Survey to the Secretary of the Interior, approved by the Secretary of the Interior on May 20, 1965, authorizing the Area Oil and Gas Supervisor, Gulf of Mexico Area, to approve core drilling on the Continental Slope of the Gulf of Mexico.

(11) Memorandum dated February 16, 1967, from the Director, Geological Survey, to the Secretary of the Interior, approved by the Secretary of the Interior on March 1, 1967, authorizing the Area Oil and Gas Supervisor, Eastern Area, to approve core drilling on the Continental Slope of the Atlantic Ocean.

(12) Notice dated December 11, 1974, Outer Continental Shelf Geological and Geophysical Exploration (39 FR 43562).

These proposed regulations also incorporate the subject matter of draft amendments of 30 CFR 250.38(g), 250.70, 250.71, 250.72, 250.73, and 250.74 appearing in a notice published in the FEDERAL REGISTER on May 16, 1974 (39 FR 17446–17447) pertaining to geological and geophysical data submission and disclosure. On the basis of public hearings held on July 15 and 16, 1974, and comments received, certain changes are incorporated in these proposed regulations.

It is the policy of the Department of the Interior, whenever practicable, to afford the public an opportunity to participate in the rule making process. Accordingly, interested parties may submit written comments, suggestions, or objections with respect to the proposed regulations to the Director, U.S. Geological Survey, National Center, Reston, Virginia 22092, on or before June 16, 1965.

Pursuant to section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)), the Department has prepared a draft Environmental Impact Statement on the proposed 30 CFR Part 251. The availability of the statement is being officially announced simultaneously with the publication of this notice. Comments thereon are being invited and will be considered in the preparation of a final Environmental Impact Statement to be published prior to any final decision on the issuance of the proposed regulations.

Dated: April 16, 1975.

ROYSTON C. HUGHES,
Assistant Secretary of the Interior.

PART 250—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

Part 250 of Title 30 of the Code of Federal Regulations is amended as set forth below:

Section 250.97 is amended to read as follows:

§ 250.97 Public inspection of records.

(a) Geophysical interpretations, maps and data and geological interpretations and maps which are submitted pursuant to the requirements of this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect, or for a period of 10 years following issuance of the lease, whichever is less, unless the Supervisor determines that earlier release of such information is necessary for the proper development of the field or area.

(b) Geological data which are submitted pursuant to the requirements of this part shall be made available for public inspection within a period of 6 months after the date of submission pursuant to the requirements of this part except that the Supervisor may extend the time for release up to a total of one year after the date of submission.

Part 251 is added to Chapter II of Title 30 of the Code of Federal Regulations to read as follows:

PART 251—GEOLOGICAL AND GEOPHYSICAL EXPLORATION OF THE OUTER CONTINENTAL SHELF

GENERAL PROVISIONS

Sec.
251.1 Purpose.
251.2 Authority and scope.
251.3 Definitions.
251.4 Requirements for conducting geological and geophysical explorations of the Outer Continental Shelf.
251.5 Responsibilities.

CONDITIONS FOR ISSUANCE OF PERMITS

251.10 Applications.
251.11 General conditions of permits.
251.12 General obligations of permittee.
251.13 Core or test drilling.
251.14 Reports.
251.15 Public availability of records.

CANCELLATION, PENALTIES AND APPEALS

251.20 Revocation and cancellation.
251.21 Penalties.
251.22 Appeals.

AUTHORITY: Sec. 11, Outer Continental Shelf Lands Act of August 7, 1953 (67 Stat. 462, 469; 43 U.S.C. 1331, 1340)

GENERAL PROVISIONS

§ 251.1 Purpose.

The purpose of the regulations in this part is to prescribe policies, procedures, and requirements for geological and geophysical exploration for mineral resources and scientific research of the Outer Continental Shelf.

§ 251.2 Authority and scope.

(a) The regulations in this part are issued pursuant to Section 11 of the Outer Continental Shelf Lands Act of August 7, 1953 (67 Stat. 462, 469, 43 U.S.C. 1331, 1340).

(b) It is the policy of the Department to encourage geological and geophysical explorations of the Outer Continental Shelf.

(c) Authorization by the Department to engage in such activities conveys no right to a lease and constitutes no commitment by the Government to offer the area covered by the authorization for leasing.

(d) The regulations in this part shall not apply to geological and geophysical explorations conducted on a lease in the Outer Continental Shelf of the United States by or on behalf of the lessee. Those explorations shall be governed by the regulations in Part 250 of this chapter.

(e) The regulations of this part are applicable to permits issued prior to publication of this part, but if there is direct conflict between the express terms of such a permit and these regulations the terms of the permit shall control.

§ 251.3 Definitions.

When used in this part, the following definitions shall apply:

(a) *Director.* The Director of the Geological Survey, United States Department of the Interior.

(b) *Supervisor.* A representative of the Secretary, or any subordinate of such representative acting under his direction, subject to the direction and supervisory authority of the Director, the Chief, Conservation Division, Geological Survey, and the appropriate Conservation Manager, Conservation Division, Geological Survey, authorized and empowered to regulate operations and to perform other duties prescribed in the regulations in this part.

(c) *Person.* A natural person, an association, a State, a political subdivision of a State, or a private, public or municipal corporation.

(d) *Geological explorations for mineral resources.* Operations which utilize geologic and geochemical techniques, including core and test drilling and various bottom sampling methods, to produce information concerning the Outer Continental Shelf. The term does not include explorations for scientific research.

(e) *Geophysical explorations for mineral resources.* Operations which utilize geophysical techniques, including gravity, magnetic and various seismic methods, to produce information concerning the Outer Continental Shelf. The term does not include explorations for scientific research.

(f) *Geological and geophysical explorations for scientific research.* Any investigation conducted for scientific research purposes involving the gathering and analysis of geological or geophysical data of the Outer Continental Shelf, the results of which will be made available to the public.

(g) *Deep stratigraphic test.* Drilling of more than 50 feet (15.2 meters) of consolidated rock or a total of 300 feet (91.4 meters).

(h) *Permit.* The contract or agreement, approved for a specified period of time, under which the permittee acquires the right to conduct (1) geological or geophysical explorations for mineral resources of the Outer Continental Shelf; or (2) scientific research of the Outer Continental Shelf which involves the use of solid or liquid explosives or the penetration of more than 50 feet (15.2 meters) or consolidated rock or a total of 300 feet (91.4 meters) under the conditions at the locations specified in the permit.

(i) *Outer Continental Shelf.* All submerged lands which lie seaward and outside the area of lands beneath navigable waters as defined in the Submerged Lands Act (67 Stat. 29; 43. U.S.C. §§ 1301–1315) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(j) *OCS Order.* A formal numbered order issued by the Supervisor with the prior approval of the Chief, Conservation Division, Geological Survey, that implements the regulations contained in this part of 30 CFR Part 250 of this Chapter and applies to operations in an area or a major portion thereof.

§ 251.4 Requirements for conducting geological and geophysical explorations of the Outer Continental Shelf.

(a) Any person wishing to conduct geological or geophysical explorations for mineral resources of the Outer Continental Shelf must obtain a permit for such exploration from the Supervisor.

(b) Any person desiring to conduct explorations for scientific research on the Outer Continental Shelf is not required to obtain a permit from the Supervisor unless such explorations involve the use of solid or liquid explosives or the penetration of more than 50 feet (15.2 meters) of consolidated rock or a total of 300 feet (91.4 meters).

(c) Agencies of the United States using Federal employees and federally-owned facilities are not required to obtain a permit to conduct geological or geophysical explorations of the Outer Continental Shelf.

(d) Persons conducting scientific research not requiring a permit and agencies of the United States shall, prior to commencing such explorations, file with the Supervisor a notice to the Director which includes:

(1) Identification of the person or agency which will conduct the proposed exploration;

(2) Type of exploration and manner in which it will be conducted;

(3) Location on the Outer Continental Shelf where the exploration will be conducted;

(4) Dates on which the exploration is to be commenced and completed;

(5) The proposed timing and manner in which the results of the exploration will be released to the public or made available through publication; and

(6) A statement that the data and the processed information derived therefrom will not be sold or withheld for exclusive use.

(e) The Director shall be notified immediately, through the Supervisor, of any adverse effects of the exploration on the environment, aquatic life, or other uses of the area in which the exploration was conducted.

§ 251.5 Responsibilities.

Subject to the authority of the Secretary of the Interior, the regulations in this part shall be administered by the Director, through the Chief, Conservation Division of the Geological Survey and the Supervisor.

(a) The Supervisor shall receive and act on applications to conduct geological or geophysical exploration of the Outer Continental Shelf. Permits for exploration involving the use of solid or liquid explosives or for penetration of more than 50 feet (15.2 meters) of consolidated rock or a total of 300 feet (91.4 meters) shall be approved only under conditions established by the Director.

(b) The Supervisor shall not issue any permit until he has found that such exploration will not interfere with or endanger operations under any lease maintained or granted pursuant to the Outer Continental Shelf Lands Act and that such exploration will not be unduly harmful to aquatic life in the area, result in pollution, create hazardous or unsafe conditions, unreasonably interfere with other uses of the area, or disturb any site, structure, or object of historical or archaeological significance.

(c) The Supervisor shall not approve an application if the applicant has demonstrated an unwillingness to conduct exploration activities in accordance with the terms and conditions of the permit and applicable OCS orders, regulations, and laws.

(d) The Supervisor may, subject to the approval of the Chief, Conservation Division, Geological Survey, issue OCS orders implementing the requirements of the regulations of this part when such implementations apply to an entire area or a major portion thereof.

(e) The Supervisor may issue written or oral orders to govern operations under a specific permit. The Supervisor shall confirm oral orders in writing as promptly as possible.

(f) When any person intending to conduct scientific research for which a permit is not required or any agency of the United States has notified the Supervisor of its desire to conduct explorations of the Outer Continental Shelf, the Supervisor shall inform the person or agency of precautions which the Director considers necessary to assure that the exploration will not interfere with or endanger operations under a lease, cause undue harm to aquatic life, cause pollution, create hazardous or unsafe conditions, unreasonably interfere with other uses of the area, or disturb any site, structure, or object of historical or archaeological significance.

(g) The Supervisor may consult with any Federal or State agency possessing expertise which he deems useful in formulating permit stipulations and conditions.

(h) The Supervisor is authorized to cooperate with State authorities and to utilize state inspection services for the protection of aquatic life and other values when such services are available.

(i) The Supervisor shall advise the appropriate officials of other bureaus and offices of the Department and other Federal and State agencies of the nature and location of exploratory activities conducted pursuant to this part which may affect their respective programs and interests.

(j) The Supervisor or his representative may order, either in writing or orally with written confirmation, the suspension of any operation conducted pursuant to a permit issued in accordance with the regulations of this part when in his judgment such operation threatens immediate, serious, and irreparable harm or damage to life, including aquatic life, property, cultural resources, any valuable mineral deposits, or the environment. Such suspension of operations under the permit shall continue until the permittee is notified in writing by the Supervisor that operations may resume.

CONDITIONS FOR ISSUANCE OF PERMITS

§ 251.10 Applications.

(a) Applications for permits to conduct geological or geophysical exploration of the Outer Continental Shelf shall be on a form approved by the Director, Geological Survey. All applications shall include:

(1) Identification of persons or agencies participating in the proposed exploration;

(2) Type of exploration and manner in which it will be conducted;

(3) Location where the exploration will be conducted;

(4) Purpose of conducting such exploration;

(5) Dates on which the exploration will be commenced and completed; and

(6) Such other information as the Supervisor may request of the applicant.

(b) Applications to conduct geological or geophysical explorations of the Outer Continental Shelf must be filed in duplicate with the Supervisor as follows:

(1) For geophysical explorations which do not involve the use of explosives, at least 10 working days before the work for which the permit is sought is scheduled to begin;

(2) For geological explorations (excluding deep stratigraphic tests) or geophysical explorations involving the use of explosives, at least 30 working days before the work for which the permit sought is scheduled to begin; and

(3) For deep stratigraphic tests, at least 90 working days before the work for which the permit is sought is scheduled to begin.

(c) Application filing locations:

(1) Applications to conduct geological and geophysical explorations for oil, gas, and surphur shall be filed in the following Geological Survey offices:

(i) For areas off the Atlantic Coast—the Area Oil and Gas Supervisor, Eastern Area, Washington, D.C.

(ii) For areas in the Gulf of Mexico—the Area Oil and Gas Supervisor, Gulf of Mexico Area, Metairie, Louisiana.

(iii) For areas off the coast of the States of California, Oregon, and Washington—the Area Oil and Gas Supervisor, Pacific Area, Los Angeles, California.

(iv) For areas off the State of Alaska—the Area Oil and Gas Supervisor, Alaska Area, Anchorage, Alaska.

(2) Applications to conduct geological or geophysical exploration for minerals other than oil, gas, and sulphur shall be filed in the following Geological Survey offices:

(i) For areas off the Atlantic Coast and in the Gulf of Mexico—the Area Mining Supervisor, Eastern Area, Washington, D.C.

(ii) For areas off the States of Alaska, California, Oregon, and Washington—the Area Mining Supervisor, Alaska—Pacific Area, Menlo Park, California.

(3) Applications to conduct scientific research on the Outer Continental Shelf which requires a permit shall be filed with the Area Oil and Gas Supervisor as indicated in paragraph (c) (1) of this section.

§ 251.11 General conditions of permits.

(a) Separate permits for geological and for geophysical explorations will be issued.

(b) Each permit shall authorize the exploration as described in the application, except to the extent that the description is modified by the terms of the permit; and will notify the permittee that it must comply with the terms and conditions of the permit, OCS orders, other orders of the Supervisor, the regulations in this part, and other applicable laws and regulations. Geological and geophysical exportation permits shall be subject to such terms and conditions as the Supervisor deems necessary including, but not limited to, terms and conditions to assure that operations will not:

(1) Interfere with or endanger operations under any lease maintained or granted pursuant to the Outer Continental Shelf Lands Act;

(2) Cause undue harm to aquatic life;

(3) Cause pollution;

(4) Create hazardous or unsafe conditions;

(5) Unreasonably interfere with or harm other uses of the area; or

(6) Disturb any site, structure, or object of historical or archaeological significance.

(c) The permit shall provide for the means by which data will be submitted to Geological Survey.

(d) The permittee shall notify appropriate agencies including the Coast Guard, the Corps of Engineers and other Federal and State agencies designated by the Supervisor prior to commencing explorations.

§ 251.12 General obligations of permittee.

(a) A permittee shall conduct explorations only in compliance with the terms and conditions of the permit, the orders of the Supervisor, the regulations in this part, and all other applicable laws and regulations, and in a manner which will not interfere with or endanger operations under any lease, or unduly harm aquatic life, result in pollution, create hazardous or unsafe conditions, unreasonably interfere with other uses of the area, or disturb any site, structure, or object of historical or archaeological significance.

(b) Upon the direction of the Supervisor, a permittee authorized to conduct geological or geophysical explorations shall utilize the services of an advisor or consultant qualified to observe and advise and who will observe operations conducted pursuant to the permit and advise the permittee and the Supervisor of any adverse effects of the operations upon the environment, aquatic life, and other uses of the area. The cost of obtaining any non-Federal advisor or consultant shall be paid by the permittee. The permittee shall, on request of the Supervisor, furnish quarters and transportation at no cost, for a Federal representative to inspect operations.

§ 251.13 Core or test drilling.

(a) Permits authorizing geological exploration by means of shallow coring or drilling may be issued by the Supervisor.

(1) Prior to issuing a permit, the Supervisor may require that high resolution seismic data including bathymetric, side-scan sonar and magnetometer data be gathered across any proposed drilling location so as to determine shallow structural detail in the vicinity of the proposed test.

(2) In order to minimize duplicative geological exploration involving penetration of the seabed of the Outer Continental Shelf, the Supervisor may require an applicant to afford all interested persons an opportunity to participate in the program on a cost-sharing basis. The penalty for late participation in such a program shall not be more than 50 percent of the cost to each of original participants. If required to provide for group participation, the applicant shall:

(i) Publish a summary statement of the proposed program in a manner approved by the Supervisor;

(ii) Allow reasonable time, but not less than 30 days from the date of publication, for other persons to consider participation in the program;

(iii) Forward a copy of the published notice(s) to the Supervisor;

(iv) Compute the direct costs to a participant in a geological exploration program by dividing the total costs of the program by the number of participants. Such figure shall be revised when additional (including late) participants join the group; and

(v) Furnish the Supervisor with a complete list of all participants under the permit prior to commencing operations and, on a timely basis, a list of all late participants.

(3) The permittee shall conduct such exploration in a manner which prevents blowouts, prevents release of fluids from stratum into the sea, and prevents communication between separate fluid-bearing strata of oil, gas, or water. The permittee shall utilize appropriate protective measures and devices specified by the Supervisor.

(b) Permits authorizing geological exploration by means of deep stratigraphic drilling on the Outer Continental Shelf may be issued by the Supervisor only after the Director has approved the drilling plan.

(1) An application to conduct deep stratigraphic drilling shall be accompanied by a drilling plan which shall include:

(i) A description of the drilling rig proposed for use showing the design and major features thereof, including features intended to prevent or control pollution;

(ii) The location of each deep stratigraphic test to be drilled including surface and projected bottom hole location for directionally drilled tests:

(iii) An oil spill contingency plan and a description of all equipment and materials available to the permittee for use in containment and recovery of an oil spill, with a description of the capabilities of such equipment under different sea and weather conditions:

(iv) High resolution seismic data including bathymetric, side-scan sonar and magnetometer data collected across any proposed drilling location so as to permit determination of shallow structural detail in the vicinity of the proposed well. and for stratigraphic wells proposed to depths greater than 1,000 feet (304.8 metres) below the mudline, common depth point seismic data from the area of the proposed test location and interpretations therefrom; and

(v) Such other pertinent information and data as the Director or Supervisor may request.

(2) Before any modification may be made in an approved drilling plan, the proposed modification must be approved by the Director. Any relocation of drillsite exceeding 300 feet (91.4 metres) or redrill of the hole shall have prior approval of the Supervisor.

(3) In order to minimize duplicative geological exploration involving penetration of the seabed of the Outer Continental Shelf, the Supervisor shall require an applicant for a permit to perform deep stratigraphic drilling to afford all interested persons an opportunity to participate in the program on a cost-sharing

basis with a penalty for late participation of not more than 100 percent of the cost to each original participant. To provide for group participation the applicant shall:

(i) Publish a summary statement of the proposed program in a manner approved by the Supervisor;

(ii) Allow reasonable time, but not less than 30 days from the date of publication, for other persons to consider participation in the program;

(iii) Forward a copy of the published notice(s) to the Supervisor;

(iv) Compute the direct cost to a participant in a geological exploration program by dividing the total cost of the program by the number of participants. Such figure shall be revised when additional (including late) participants join the group; and

(v) Furnish the Supervisor with a complete list of all participants under the permit prior to commencing operations and submit, on a timely basis, a list of all late participants.

(c)(1) Prior to any coring or drilling activity, the permittee will conduct studies sufficient to determine the possible existence of any sites, structures, or objects of historical or archaeological significance that may be affected by such an operation, and shall report the findings of the studies to the Supervisor. If any study indicates the possible presence of a cultural resource, a full explanation will be included in the report and the Supervisor shall take appropriate action.

(2) The permittee shall take no action that may result in its disturbance without the prior approval of the Supervisor, but if any cultural resource is accidentally discovered, the permittee shall immediately report the finding to the Supervisor and make every reasonable effort to preserve and protect the cultural resource from damage until the Supervisor has given directions as to its disposition.

(d) All Outer Continental Shelf Regulations relating to drilling operations in Part 250 of this chapter and all OCS Orders relating to the drilling and abandonment of wells apply as appropriate to permits to drill, issued pursuant to this part. Departures from the requirements of OCS Orders shall be permitted as provided for in § 250.12(b) of this chapter.

(e) Bonds. Before a permit authorizing coring or drilling will be issued, the applicant shall furnish to the Bureau of Land Management a corporate security bond of not less than $100,000 conditioned on compliance with the terms of the permit, unless he already maintains with or furnishes to the Bureau of Land Management a bond in the sum of $300,000 conditioned on compliance with the terms of exploration permits issued to him on the Outer Continental Shelf in (1) Gulf of Mexico, (2) along the Pacific Coast, (3) along the Atlantic Coast, or (4) other area of operations, as may be appropriate. The bond furnished or maintained by the applicant will be on a form approved by the Supervisor.

§ 251.14 Reports.

(a) The Director shall be notified immediately, through the Supervisor, of any adverse effects of the exploration on the environment, aquatic life or other uses of the Area in which the exploration was conducted or on any site, structure, or object of historical or archaeological significance.

(b) The permittee shall send interim reports which include a daily log of operations to the Supervisor on a weekly basis.

(c) The permittee shall submit a final report to the Supervisor within 30 days after the completion of any exploration activity. The final report shall contain the following:

(1) A description of the work performed;

(2) Charts, maps, or plats depicting the areas in which the exploration was conducted and specifically identifying the lines over which geophysical traverses were run or the specific locations at which geological explorations were conducted, including a reference sufficient to identify the data produced during each such operation;

(3) The dates on which the exploration was performed;

(4) A report of any adverse effects of the exploration on the environment, aquatic life, any lease operations in the area, or other uses of the area in which the exploration was conducted, or on any site structure or object of historical or archaeological significance.

(5) The data required to be submitted in paragraphs (d) and (e) of this section; and

(6) Such other information as may be specified by the Supervisor.

(d) In addition to the reports required in paragraphs (a), (b), (c) of this section, upon request by the Supervisor, the following geological data and processed information acquired under geological exploration permit shall be submitted to the Supervisor within 30 days after request. The time for submitting processed data may be extended by the Supervisor if the permittee shows that additional time is necessary to complete data processing.

(1) Accurate and complete records of all geological and geochemical data resulting from each drilling operation;

(2) Paleontological reports identifying microscopic fossils by depth (not resulting age interpretations based upon such identification) unless washed samples are maintained by the permittee for paleontological determination and are made available for inspection by the Geological Survey;

(3) Copies of logs or charts of electrical, radioactive, sonic, and other well logging operations;

(4) Analyses of core or bottom samples of a representative cut or split of the core or bottom sample;

(5) Detailed descriptions of any hydrocarbon shows or hazardous conditions encountered during operations, including near losses of well control, abnormal geopressures, and losses of circulation; and

(6) Such other geological and geochemical data and processed information obtained under the permit as may be specified by the Supervisor.

(e) In addition to the reports required in paragraphs (a), (b), and (c) of this section, upon request by the Supervisor, the following geophysical data and processed information acquired under a geophysical exploration permit shall be submitted to the Supervisor within 30 days after request. The time for submitting processed data may be extended by the Supervisor if the permittee shows that additional time is necessary to complete data processing.

(1) Accurate and complete records of each geophysical survey conducted under the exploration permit, including final location maps of all survey stations; and

(2) All common depth point and high resolution seismic data developed under an exploration permit including the processed information derived therefrom with extraneous signals and interference removed, in a format and quality suitable for interpretative evaluation, reflecting state-of-the-art processing techniques; and other data including, but not limited to, shallow and deep subbottom profiles, bathymetry, side-scan sonar magnetometer, and bottom profiles; gravity and magnetic; and data from special studies such as from refraction surveys, velocity surveys and domal configuration studies.

§ 251.15 Public availability of records.

Geological and geophysical data, including processed information relating to submerged lands on the Outer Continental Shelf collected pursuant to a permit issued after the publication of these regulations and required to be submitted to the Supervisor under this part, shall be made available for public inspection by the Supervisor as follows:

(a) Geophysical data including processed information—ten years after issuance of a permit to conduct exploration.

(b) Geological data and processed information:

(1) Immediate release through public notice of the discovery during drilling operations of oil shows and environmental hazards on unleased lands when these shows or hazards are judged to be significant by the Director.

(2) Ten years after issuance of the permit to conduct exploration except for deep stratigraphic drilling.

(3) Five years after the date of completion of a test well or 60 calendar days after the issuance of the first Federal lease within 50 geographic miles of the drill site, whichever is earliest, for deep stratigraphic drilling.

CANCELLATION, PENALTIES AND APPEALS

§ 251.20 Revocation and cancellation.

The Supervisor is authorized to suspend or revoke a permit under which the operation is being conducted, or is proposed to be conducted, which in his judgment threatens immediate, serious, or irreparable harm or damage to life, including aquatic life, to property, to cultural resources, to valuable mineral deposits, or to the environment, or for noncompliance with applicable laws, regulations, the terms and conditions of the permit, OCS Orders, or any other written order or rule, including orders for submitting reports, well records or logs, and analyses in a timely manner.

§ 251.21 Penalties.

Any person who conducts geological and geophysical exploration of the Outer Continental Shelf without a permit issued under this part or who, having obtained a permit, fails to comply with the terms of the permit will be subject to any civil or criminal remedies which the Secretary chooses to pursue.

§ 251.22 Appeals.

Orders or decisions issued under the regulations in this part may be appealed as provided in Part 290 of this chapter.

[FR Doc. 75-10490 Filed 4-21-75; 8:45 am]

APPENDIX XVII. NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL, GAS, AND SULPHUR LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

(OSC Order Nos. 1 through 12—Gulf of Mexico)

[OCS Order No. 1, Aug. 28, 1969]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA—MARKING OF WELLS, PLATFORMS, AND FIXED STRUCTURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.37. Section 250.37 provides as follows:

"*Well designations.*—The lessee shall mark promptly each drilling platform or structure in a conspicuous place, showing his name or the name of the operator, the serial number of the lease, the identification of the wells, and shall take all necessary means and precautions to preserve these markings."

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Identification of Platforms, Fixed Structures

Platforms and structures, other than individual wellhead structures and small structures, shall be identified at two diagonal corners of the platform or structure by a sign with letters and figures not less than 12 inches in height with the following information: The name of lease operator, the name of the area, the block number of the area in which the platform or structure is located, and the platform or structure designation. The information shall be abbreviated as in the following example: "The Blank Oil Company operates 'C' platform in Block 37 of South Timbalier Area."

The identifying sign on the platform would show: "BOC—S.T.—37—C."

2. Identification of Single Well Structures and Small Structures

Single well and small structures may be identified with one sign only, with letters and figures not less than 3 inches in height. The information shall be abbreviated as in the following example: "The Blank Oil Company operates well No. 1 which is equipped with a protective structure, in Block 68 in the East Cameron Area."

The identifying sign on the protective structure would show: "BOC—E.C.—68—No. 1"

3. Identification of Wells

The OCS lease and well number shall be painted on, or a sign affixed to, each singly completed well. In multiple completed wells each completion shall be individually identified at the well head. All identifying signs shall be maintained in a legible condition.

ROBERT F. EVANS, *Supervisor.*

Approved: August 28, 1969

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 2, Aug. 28, 1969]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA—DRILLING PROCEDURES OFF LOUISIANA AND TEXAS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.34, 250.41 and 250.91. All exploratory wells drilled for oil and gas shall be drilled in accordance with the provisions of this Order. Initial development wells drilled for oil and gas shall be drilled in accordance with the provisions of this Order which shall continue in effect until field rules are issued. After field rules have been established by the supervisor, development wells shall be drilled in accordance with such rules; except that in Application to Drill (Form 9-331C) for exploratory wells and development wells commenced prior to October 1, 1969, may be excluded from provisions of this Order, as approved by the supervisor, to permit time for the establishment of field rules.

Where sufficient geologic and engineering information is obtained through exploratory drilling, operators may make application to the supervisor for the establishment of field rules, but the operator(s) shall make such application before more than five development wells have been drilled in the field. Operators may also make application for the establishment of field rules for existing fields containing more than five development wells on the date of this Order. Each Application to Drill (Form 9-331C) for exploratory wells and development wells not covered by field rules shall include all information required under 30 CFR 250.91 and the integrated casing, cementing, mud, and blowout prevention program for the well, and shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Well Casing and Cementing

All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). The Application to Drill (Form 9-331C) shall contain a statement that all zones which contain oil, gas, or fresh water shall be fully protected by casing and cement. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural casing, conductor casing, surface casing, intermediate casing, and production casing. All depths refer to true vertical depth (TVD).

A. *Drive or Structural Casing.*—This casing shall be set by drilling, driving, or jetting to a minimum depth of 100 feet below the Gulf floor or to such greater depth required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the Gulf, and a quantity of cement sufficient to fill the annular space back to the Gulf floor must be used.

B. *Conductor and Surface Casing—General Principles.*—Determination of proper casing setting depths shall be based upon all geologic factors including the presence or absence of hydrocarbons and water depths on a well-for-well basis. The setting depths of all casing strings shall be determined by taking into account formation fracture gradients and hydrostatic pressure to be contained within the well bore. The conductor and surface casing shall be new pipe or reconditioned pipe that has been tested and inspected to verify a new condition.

(1) *Conductor Casing.*—This casing shall be set in accordance with the table below. A quantity of cement sufficient to fill the annular space back to the Gulf floor must be used. The cement may be washed out or displaced to a depth of 40 feet below the Gulf floor to facilitate casing removal upon well abandonment.

(2) *Surface Casing.*—This casing shall be set at a depth in accordance with the table below and cemented in a manner necessary to protect all fresh water sands and provide well control until the next string of casing is set. This casing shall be cemented with a quantity sufficient to fill the calculated annular space to (a) at least 1,500 feet above the casing shoe, or (b) within 200 feet below the conductor casing. When-

ever there are any indications of improper cementing, such as lost returns, cement channeling, or mechanical failure of equipment, a temperature or cement bond survey shall be run, either before or after remedial cementing, to aid in determining whether the casing is properly cemented. If the annular space is not adequately cemented by the primary operation, the operator shall either recement or squeeze cement the shoe after drilling out.

(3) *Conductor and Surface Casing Setting Depths.*—These strings of casing shall be set at the depths specified in the following table subject to minor variation to permit the casing to be set in a competent bed: provided, however, that the conductor casing shall be set before drilling into shallow formations known to contain oil or gas or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. For those wells which may encounter abnormal pressure conditions, the district engineer may prescribe the exact setting depth within the ranges specified below.

REQUIRED SETTING DEPTH BELOW GULF FLOOR (TVD IN FEET)

	Surface casing		Conductor casing	
	Minimum	Maximum	Minimum	Maximum
Proposed total depth of well or depth of 1st full string of intermediate casing (TVD in feet from rotary table):				
0 to 7,000	1,500	2,500	300	800
7,000 to 9,000	1,750	3,000	400	800
9,000 to 11,000	2,250	3,500	500	900
11,000 to 13,000	3,000	4,000	600	900
13,000 or below	3,500	4,500	700	1,000

C. *Intermediate Casing.*—This string of casing shall be set when required by anticipated abnormal pressure, mud weights, sediment and other well conditions. The intermediate casing shall be new pipe or reconditioned pipe that has been tested and inspected to verify a new condition. A quantity of cement sufficient to cover and isolate all hydrocarbon zones and to isolate abnormal pressure intervals from normal pressure intervals shall be used. If a liner is used as an intermediate string, the cement shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and next larger string has been achieved. The test shall be recorded on the driller's log. When such liner is used as production casing, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

D. *Production Casing.*—This string of casing shall be set before completing the well for production. The production casing shall be new pipe or reconditioned pipe that has been tested and inspected to verify a new condition. It shall be cemented in a manner necessary to cover or isolate all zones which contain hydrocarbons, but in any case, a calculated volume sufficient to fill the annular space at least 500 feet above the uppermost productible hydrocarbon zone must be used. When a liner is used as production casing, the testing of the seal between the liner top and next larger string shall be conducted as in the case of intermediate liners.

E. *Pressure Testing.*—Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure tested as shown in the table below. This test shall not exceed the working pressure of the casing. The surface casing shall be tested with water in the top 100 feet of the casing. If the pressure declines more than 10% in 30 minutes, or if there is other indication of a leak, the casing shall be recemented, repaired, or an additional casing string run, and the casing shall be tested again in the same manner.

Casing string and minimum pressure test (psi)

Conductor: 200.
Surface: 1,000.
Intermediate: 1,500 or 0.2 psi/ft., whichever is greater.

Liner: 1,500 or 0.2 psi/ft., whichever is greater.
Production: 1,500 or 0.2 psi/ft., whichever is greater.
After cementing any of the above strings, drilling shall not be commenced until a time lapse of:

(1) 24 hours, or

(2) 8 hours under pressure for conductor casing string. 12 hours under pressure for all other strings (Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure is used.)

All casing pressure tests shall be recorded on the driller's log.

2. *Blowout Prevention Equipment*

Blowout preventers and related well control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the conductor casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed, as follows:

A. *Conductor Casing.*—Before drilling below this string, at least one remotely controlled bag-type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. To avoid formation fracturing from complete shut-in of the well, a large diameter pipe with control valves shall be installed on the conductor casing below the blowout preventer so as to permit the diversion of hydrocarbons and other fluids; except that when the blowout preventer assembly is on the Gulf floor, the choke and kill lines shall be equipped to permit the diversion of hydrocarbons and other fluids.

B. *Surface Casing.*—Before drilling below this string the blowout prevention equipment shall include a minimum of: (1) three remotely controlled, hydraulically operated, blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one bag-type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke manifold; (4) a kill line; and (5) a fill-up line.

C. *Intermediate Casing.*—Before drilling below this string the blowout prevention equipment shall include a minimum of: (1) four remotely controlled, hydraulically operated, blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including at least one equipped with pipe rams, one with blind rams, and one bag-type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke manifold; (4) a kill line; and (5) a fill-up line.

D. *Testnig.*—Ram-type blowout preventers and related control equipment shall be tested with water to the rated working pressure of the stack assembly or to the working pressure of the casing, whichever is the lesser, (1) when installed; (2) before drilling out after each string of casing is set; (3) not less than once each week while drilling; and (4) following repairs that require disconnecting a pressure seal in the assembly. The bag-type blowout preventer shall be tested to 70 percent of the above pressure requirements.

While drill pipe is in use ram-type blowout preventers shall be actuated to test proper functioning once each trip, but in no event less than once each day. The bag-type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a pressure capacity reserve at all times to provide for repeated operation of hydraulic preventers. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded on the driller's log.

E. *Other Equipment.*—An inside blowout preventer assembly (back pressure valve) and drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Separate valves shall be maintained on the rig floor to fit all pipe in the drill string. A Kelly cock shall be installed below the swivel, and an essentially full opening Kelly cock shall be installed at the bottom of the Kelly of such design that it can be run through the blowout preventers.

3. Mud Program—General

The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times.

A. Mud Control.—Before starting out of hole with drill pipe, the mud shall be circulated with the drill pipe just off bottom until the mud is properly conditioned. When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops below 100 feet, and a mechanical device for measuring the amount of mud required to fill the hole shall be utilized. The volume of mud required to fill the hole shall be watched, and any time there is an indication of swabbing, or influx of formation fluids, the necessary safety device(s) required in subparagraph 2(E) above shall be installed on the drill pipe, the drill pipe shall be run to bottom, and the mud properly conditioned. The mud shall not be circulated and conditioned except on or near bottom, unless well conditions prevent running the pipe to bottom. The mud in the hole shall be circulated or reverse circulated prior to pulling drill stem test tools from the hole.

B. Mud Testing Equipment.—Mud testing equipment shall be maintained on the drilling platform at all times, and mud test shall be performed daily, or more frequently as conditions warrant.

The following mud system monitoring equipment must be installed (with derrick floor indicators) and used throughout the period of drilling after setting and cementing the conductor casing:

(1) Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual or audio warning device.

(2) Mud volume measuring device for accurately determining mud volumes require to fill the hole on trips.

(3) Mud return indicator to determine that returns essentially equal the pump discharge rate.

ROBERT F. EVANS, *Supervisor.*

Approved: August 28, 1969

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 3, Aug. 28, 1969]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA—PLUGGING AND ABANDONMENT OF WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance 30 CFR 250.15. The operator shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil and gas. Plugging and abandonment operations must not be commenced prior to obtaining approval from an authorized representative of the Geological Survey. Oral approvals shall be in accordance with 30 CFR 250.13. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Permanent Abandonment

A. *Isolation in Uncased Hole.*— In uncased portions of wells, cement plugs shall be spaced to extend 100 feet below the bottom to 100 feet above the top of any oil, gas, and fresh water zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata.

B. *Isolation of Open Hole.*—Where there is open hole (uncased and open into the casing string above) below the casing, a cement plug shall be placed in the deepest casing string by (1) or (2) below, or in the event lost circulation conditions exist or are anticipated, the plug may be placed in accordance with (3) below:

(1) A cement plug placed by displacement method so as to extend a minimum of 100 feet above and 100 feet below the casing shoe.

(2) A cement retainer with effective back pressure control set not less than 50 feet, nor more than 100 feet, above the casing shoe with a cement plug

calculated to extend at least 100 feet below the casing shoe and 50 feet above the retainer.

(3) A permanent type bridge plug set within 150 feet above the casing shoe with 50 feet of cement on top of the bridge plug. This plug shall be tested prior to placing subsequent plugs.

C. *Plugging or Isolating Perforated Intervals.*—A cement plug shall be placed opposite all open perforations (perforations not squeezed with cement) extending a minimum of 100 feet above and 100 feet below the perforated interval or down to a casing plug whichever is less. In lieu of the cement plug, a bridge plug set at a maximum of 150 feet above the open perforations with 50 feet of cement on top may be used provided the perforations are isolated from the hole below.

D. *Plugging of Casing Stubs.*—If casing is cut and recovered, a cement plug 200 feet in length shall be placed to extend 100 feet above and 100 feet below the stub. A retainer may be used in setting the required plug.

E. *Plugging of Annular Space.*—No annular space that extends to the Gulf floor shall be left open to drilled hole below. If this condition exists, the annulus shall be plugged with cement.

F. *Surface Plug Requirement.*—A cement plug of at least 150 feet, with the top of the plug 150 feet or less below the Gulf floor, shall be placed in the smallest string of casing which extends to the surface.

G. *Testing of Plugs.*—The setting and location of the first plug below the top 150-foot plug, will be verified by either (1) placing a minimum pipe weight of 15,000 pounds on the plug, or (2) testing with a minimum pump pressure of 1,000 psig with no more than a 10 percent pressure drop during a 15-minute period.

H. *Mud.*—Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval.

I. *Clearance of Location.*— All casing and piling shall be severed and removed to at least 15 feet below the Gulf floor and the location shall be dragged to clear the well site of any obstructions.

[OCS Order No. 4, Aug. 28, 1969]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA—SUSPENSIONS AND DETERMINATION OF WELL PRODUCIBILITY

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12(d)(1). An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of operations or production, or both, has been approved. An application for suspension of production for an initial period should be submitted prior to the expiration of the term of a lease. The supervisor may approve a suspension of production provided at least one well has been drilled on the lease and determined to be capable of being produced in paying quantities. The temporary or permanent abandonment of a well will not preclude approval a suspension of production as provided in 30 CFR 250.12(d)(1). Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

A well may be determined to be capable of producing in paying quantities when the requirements of either 1 or 2 below have been met.

1. Production Tests

A. *Oil Wells.*—A production test of at least two hours duration, following stabilization, is required.

B. *Gas Wells.*—A deliverability test of at least two hours duration, following stabilization, or a four-point back-pressure test, is required.

C. *Witnessing and Results.*—All tests must be witnessed by an authorized representative of the Geological Survey. Test data accompanied by operator's affidavit, or third-party test data, may be accepted in lieu of a witnessed test provided prior approval is obtained from the appropriate district office. The results of the witnessed or accepted test must justify a determination that the well is capable of producing in paying quantities.

2. Production Capability

Information for determination should be submitted in time to permit one week for evaluation and determination. In cases of urgency, determinations may be conveyed orally. The following may be considered as acceptable evidence that a well is capable of producing in paying quantities:

A. An induction-electric log of the well, clearly showing a minimum of 15 feet of producible sand in one section which does not include any interval which appears to be water saturated. All of the section counted as producible must exhibit the following properties:

(1) Electrical spontaneous potential exceeding 20 negative millivolts beyond the shale base line. If mud conditions prevent a 20 negative millivolt reading beyond the shale base line, a gamma ray log deflection of at least 70 percent of the maximum gamma ray deflection in the nearest clean water bearing sand may be substituted.

(2) A minimum true resistivity ratio of the producible section to the nearest clean water sand of at least 5:1, provided the producible section exhibits a minimum resistivity of 2.0 ohm-meters.

(3) A porosity log indicating porosity in the producible section.

B. Sidewall cores and core analysis which indicates that the section is producible.

C. A wire line formation test or evidence that an attempt was made to obtain such test. The test results must indicate that the section is producible.

D. All logs run must support other evidence that the section is productible.

ROBERT F. EVANS,
Supervisor.

Approved: August 28, 1969
RUSSELL G. WAYLAND, *Chief, Conservation Division.*

[OCS Order No. 5, June 5, 1972]

DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA—INSTALLATION OF SUBSURFACE SAFETY DEVICE

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.41(b). Section 250.41(b) provides as follows:

"(b) *Completed Wells.*—In the conduct of all its operations, the lessee shall take all steps necessary to prevent blowouts, and the lessee shall immediately take whatever action is required to bring under control any well over which control has been lost. The lessee shall: (1) in wells capable of flowing oil or gas, when required by the supervisor, install and maintain in operating condition storm chokes or similar subsurface safety devices; (2) for producing wells not capable of flowing oil or gas, install and maintain surface safety valves with automatic shutdown controls; and (3) periodically test or inspect such devices or equipment as prescribed by the supervisor."

The operator shall comply with the following requirements. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). All applications for approval under the provisions of this Order shall be submitted to the appropriate District office. References in this Order to approvals, determinations, or requirements are to those given or made by the Supervisor or his delegated representative.

1. Installation

All new and existing tubing installations open to hydrocarbon-bearing zones shall be equipped with a subsurface-controlled or a surface- or other remotely controlled subsurface safety device, to be installed at a depth of 100 feet or more below the sea floor unless, after application and justification, the well is determined to be incapable of flowing oil or gas. These installations shall be made as-required in subparagraphs A and B below within two (2) days after stabilized production is established, and during this period of time the well shall not be left unattended while open to production.

A. New Wells.—All tubing installations in wells completed after December 1, 1972, shall be equipped with a surface- or other remotely controlled subsurface safety device; provided, that wells with a shut-in tubing pressure of 4,000 psig or greater shall be equipped with a subsurface-controlled subsurface safety device in lieu of a surface- or other remotely controlled subsurface safety device unless a surface- or other remotely controlled subsurface safety device shall be installed when the tubing is first removed and declines below 4,000 psig, a surface- or other remotely controlled subsurface safety device shall be installed when the tubing is first removed and reinstalled.

B. Existing Wells.—All tubing installations in wells existing on the date of this Order shall be equipped with a surface- or other remotely controlled subsurface safety device when the tubing is first removed and reinstalled after December 1, 1972; provided, that wells with a shut-in tubing pressure of 4,000 psig or greater shall be equipped with a subsurface-controlled subsurface safety device in lieu of a surface- or other remotely controlled subsurface safety device unless a surface- or other remotely controlled subsurface safety device is approved or required. When the shut-in tubing pressure declines below 4,000 psig, a surface- or other remotely controlled subsurface safety device shall be installed when the tubing is first removed and reinstalled.

Tubing installations in existing wells completed from single-well and multi-well satellite caissons or jackets and sea-floor completions may be equipped with a subsurface-controlled subsurface safety device, in lieu of a surface- or other remotely controlled subsurface safety device, upon application, justification, and approval.

C. Shut-in Wells.—A tubing plug shall be installed in lieu of, or in addition to, other subsurface safety devices if a well has been shut in for a period of six (6) months. Such plugs shall be set at a depth of 100 feet or more below the sea floor. All retrievable plugs installed after the date of this Order shall be of the pump-through type. All wells perforated and completed, but not placed on production, shall be equipped with a subsurface safety device or tubing plug within two (2) days after completion.

D. Injection Wells.—Subsurface safety devices as required in subparagraphs A and B above shall be installed in all injection wells unless, after application and justification, it is determined that the well is incapable of flowing oil or gas, which condition shall be verified annually.

2. *Technological Advancement.*

As technological research, progress, and product improvement result in increased effectiveness of existing safety devices or the development of new devices or systems, such devices or systems may be required or used upon application, justification, and approval. Applications for routine use shall include evidence that the device or system has been field-tested at least once each month for a minimum of six (6) consecutive months, and that each test indicated proper operation.

3. *Testing and Inspection*

Subsurface safety devices shall be designed, adjusted, installed, and maintained to insure reliable operation. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface safety device has been installed in the well.

A. Surface-Controlled Subsurface Safety Devices.—Each surface or other remotely controlled subsurface safety device installed in a well shall be tested in place for proper operation when installed and thereafter at intervals not exceeding six (6) months. If the device does not operate properly, it shall be removed, repaired, and reinstalled or replaced and tested to insure proper operation.

B. Subsurface-Controlled Subsurface Safety Devices.—Each subsurface-controlled subsurface safety device installed in a well shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding six (6) months; provided, that such removable devices set in a landing nipple shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding twelve (12) months. Each velocity-type device shall be designed to close at a flow rate not to exceed the larger of either 150 percent of, or 200 BFPD above, the most recent well-test rate which equals or exceeds the approved production rate. The above closing flow rate shall not exceed the calculated capacity of the well to produce against a flowing wellhead pressure of 50 psig. Each preset tubing-pressure-actuated device shall be designed to close prior to reduction of the flowing wellhead pressure to 50 psig.

C. Tubing Plugs.—A shut-in well equipped with a tubing plug shall be inspected for leakage by opening the well to possible flow at intervals not exceeding (6) months. If sustained liquid flow exceeds 400 cc/min., or gas flow exceeds 15 cu. ft./min., the plug shall be removed, repaired, and reinstalled or an additional tubing plug installed to prevent leakage.

4. Temporary Removal

Each wireline- or pumpdown-retrievable subsurface safety device may be removed, without further authority or notice, for a routine operation which does not require approval of a Sundry Notice and Report on Wells (Form 9-331) for a period not to exceed fifteen (15) days. The well shall be clearly identified as being without a subsurface safety device and shall not be left unattended while open to production. The provisions of this paragraph are not applicable to the testing and inspection procedures in paragraph 3 above.

5. Additional Protective Equipment

All tubing installations made after the date of this Order in which a wireline- or pumpdown-retrievable subsurface safety device is to be installed shall be equipped with a landing nipple, with flow couplings or other protective equipment above and below, to provide for setting of the subsurface safety device. All wells in which a subsurface safety device or tubing plug is installed shall have the tubing-casing annulus packed off above the uppermost open casing perforations. The control system for all surface-controlled subsurface safety devices shall be an integral part of the platform shut-in system, or of an independent remote shut-in system.

6. Departures

All departures (or waivers) approved prior to the date of this Order are hereby terminated as of December 1, 1972, unless new applications are submitted prior to that date. All such new applications will be considered for approval pursuant to 30 CFR 250.12(b) and the requirements of this Order. All applications for departures shall include a detailed statement of the well conditions, efforts made to overcome any difficulties, and proposed alternate safety measures.

7. Emergency Action

All tubing installations open to hydrocarbon-bearing zones and not equipped with a subsurface safety device as permitted by this Order shall be clearly identified as not being so equipped, and a subsurface safety device or tubing plug shall be available at the field location. In the event of an emergency, such as an impending hurricane, such device or plug shall be promptly installed within the limits of practicability, due consideration being given to personnel safety.

8. Records

The operator shall maintain the following records for a minimum period of one year for each subsurface safety device and tubing plug installed, which records shall be available to any authorized representative of the Geological Survey.

A. Field Records.—Individual well records shall be maintained at or near the field and shall include, as a minimum, the following information:

(1) A record which will give design and other information; i.e., make, model, type, spacers, bean and spring size, pressure, etc.

(2) Verification of assembly by a qualified person in charge of installing the device and installation date.

(3) Verification of setting depth and all operational tests as required in this Order.

(4) Removal date, reason for removal, and reinstallation date.

(5) A record of all modifications of design in the field.

(6) All mechanical failures or malfunctions, including sand-cutting, of such devices, with notation as to cause or probable cause.

(7) Verification that a failure report was submitted.

B. *Other Records.*—The following records, as a minimum, shall be maintained at the operator's office:

(1) Verified design information of subsurface-controlled subsurface safety devices for the individual well.

(2) Verification of assembly and installation to design information.

(3) All failure reports.

(4) All laboratory analysis reports of failed or damaged parts.

(5) Quarterly failure-analysis report.

9. Reports

Well completion reports (Form 9-330) and any subsequent reports of workover (Form 9-331) shall include the type and the depth of the subsurface safety devices and tubing plugs installed in the well or indicate that a departure has been granted.

To establish a failure-reporting and corrective-action program as a basis for reliability and quality control, each operator shall submit a quarterly failure-analysis report to the office of the Supervisor, identifying mechanical failures by lease and well, make and model, cause or probable cause of failure, and action taken to correct the failure. The reporting period shall begin the first day of the month following the date of this

Order. The reports shall be submitted by February 28, May 31, August 31, and November 30 for the periods ending January 31, April 30, July 31, and October 31 of each year.

ROBERT F. EVANS, *Supervisor.*

Approved: June 5, 1972.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 6, Aug. 28, 1969]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA—PROCEDURE FOR COMPLETION OF OIL AND GAS WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.92. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Wellhead Equipment and Testing Procedures

A. *Wellhead Equipment.*—All completed wells shall be equipped with casingheads, wellheads fittings, valves and connections with a rated working pressure equal to or greater than surface shut-in pressure of the well. Connections and valves shall be designed and installed to permit fluid to be pumped between any two strings of casing. Two master valves shall be installed on the tubing in wells with a surface pressure in excess of five thousand pounds per square inch. All wellhead connections shall be assembled and tested, prior, to installation, by a fluid pressure which shal lbe equal to the rated test pressure of the fitting to be installed.

B. *Testing Procedure.*—Any wells showing sustained pressure on the casinghead, or leaking gas or oil between the production casing and the next larger casing string, shall be tested in the following manner: The well shall be killed with water or mud and pump pressure applied. Should the pressure at the casinghead reflect the applied pressure, the casing shall be condemned. After corrective measures have been taken, the casing shall be tested in the same manner. This testing procedure shall be used when the origin of the pressure cannot be determined otherwise.

2. Storm Choke

All completed wells shall meet the requirements prescribed in OCS Order No. 5.

3. Procedures for Multiple or Tubingless Completions

A. *Multiple Completions*

(1) Information shall be submitted on, or attached to, Form 9-331 showing top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.

(2) When zones approved for multiple completion become intercommunicated the lessee shall immediately repair and separate the zones after approval is obtained.

B. *Tubingless Completions*

(1) All tubing strings in a multiple completed well shall be run to the same depth below the deepest producible zone.

(2) The tubing string(s) shall be new pipe and cemented with a sufficient volume to extend a minimum of 500 feet above the uppermost producible zone.

(3) A temperature or cement bond log shall be run in all tubingless completion wells where lost circulation or other unusual circumstances occur during the cementing operations.

(4) Information shall be submitted on, or attached to, Form 9-331 showing the top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.

ROBERT F. EVANS, *Supervisor.*

Approved: August 28, 1969

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 7, Effective August 28, 1969]

U.S. DEPARTMENT OF THE INTERIOR, GULF OF MEXICO AREA

POLLUTION AND WASTE DISPOSAL

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.43. Section 250.43 provides as follows:

"(a) The lessee shall not pollute land or water or damage the aquatic life of the sea or allow extraneous matter to enter and damage any mineral- or water-bearing formation. The lessee shall dispose of all liquid and non-liquid waste materials as prescribed by the supervisor. All spills or leakage of oil or waste materials shall be recorded by the lessee and, upon request of the supervisor, shall be reported to him. All spills or leakage of a substantial size or quantity, as defined by the supervisor, and those of any size or quantity which cannot be immediately controlled also shall be reported by the lessee without delay to the supervisor and to the Coast Guard and the Regional Director of the Federal Water Pollution Control Administration. All spills or leakage of oil waste materials of a size or quantity specified by the designee under the pollution contingency plan shall also be reported by the lessee without delay to such designee.

"(b) If the waters of the sea are polluted by the drilling or production operations conducted by or on behalf of the lessee, and such pollution damages or threatens to damage aquatic life, wildlife, or public or private property, the control and total removel of the pollutant, wheresoever found, proximately resulting therefrom shall be at the expense of the lessee. Upon failure of the lessee to control and remove the pollutant the supervisor, in cooperation with other appropriate agencies of the Federal, State and local governments, or in coöperation with the lessee, or both, shall have the right to accomplish the control and removal of the pollutant in accordance with any established contingency plan for combating oil spills or by other means at the cost of the lessee. Such action shall not relieve the lessee of anw responsibility as provided herein.

"(c) The lessee's liability to third parties, other than for cleaning up the pollutant in accordance with subsection (b) above, shall be governed by applicable law."

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Pollution Prevention

In the conduct of all oil, gas and sulphur operations, the operator shall prevent pollution of the waters of the Gulf of Mexico. The operator shall comply with the following pollution prevention requirements:

A. *Liquid Disposal*

(1) Oil in any form shall not be disposed of into the waters of the Gulf.

(2) Liquid waste materials containing substances which may be harmful to aquatic life or wildlife, or injurious in any manner to life or property, shall be treated to avoid disposal of harmful substances into the waters of the Gulf.

(3) Drilling mud containing oil shall not be disposed of into the Gulf. Drilling mud containing toxic substances shall be neutralized prior to disposal.

B. *Solid Waste Disposal*

(1) Drill cuttings, sand, and other solids containing oil shall not be disposed of into the Gulf unless the oil has been removed.

(2) Mud containers and other solid waste materials shall be incinerated or transported to shore for disposal.

C. *Production Facilities*

(1) All production facilities, such as separators, tanks, treaters, and other equipment, shall be such as are necessary to control the maximum anticipated pressures and production of oil, gas, and sulphur, and shall be maintained at all times in a manner necessary to prevent pollution.

(2) All platforms and structures shall be curbed and connected by drains to a collecting tank or sump unless drip pans, or equivalents, are placed under equipment, from which a pollutant may spill into the Gulf, and piped to a tank or sump.

(3) The operator's personnel shall be thoroughly instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Non-operator personnel shall be informed in writing, prior to executing contracts, of the operator's obligations to prevent pollution.

2. Inspections and Reports

The operator shall comply with the following pollution inspection and reporting requirements:

A. *Pollution Inspections*

(1) Manned facilities shall be inspected daily.

(2) Unattended facilities, including those equipped with remote control and monitoring systems, shall be inspected at frequent intervals. The district engineer may prescribe the frequency of inspections for these facilities.

B. *Pollution Reports*

(1) All spills or leakage of oil and liquid pollutants shall be recorded showing the cause, size of spill, and action taken, and the record shall be maintained and available for inspection by the supervisor. All spills or leakage of less than 15 barrels shall be reported to the district engineer when requested by him.

(2) All spills or leakage of oil and liquid pollutants of 15 to 50 barrels shall be reported orally to the district engineer without delay and shall be confirmed in writing.

(3) All spills or leakage of oil and liquid pollutants of a substantial size or quantity, which is defined as more than 50 barrels, and those of any size or quantity which cannot be immediately controlled, shall be reported orally without delay to the supervisor, the district engineer, the Coast Guard, and the Regional Director, Federal Water Pollution Control Administration. All oral reports shall be confirmed in writing.

(4) All operators shall notify each other upon observation of equipment malfunction or pollution resulting from another's operation.

3. Control and Removal

A. Corrective Action.—Immediate corrective action shall be taken in all cases where pollution has occurred. Each operator shall have an emergency plan for initiating corrective action to control and remove pollution and such plan shall be filed with the supervisor. Corrective action taken under the plan shall be subject to modification when directed by the supervisor.

B. Equipment.—Standby pollution equipment shall be maintained by or shall be immediately available to each operator at a land base location. This equipment shall include containment booms, skimming apparatus, and approved chemical dispersants and shall be available prior to the commencement of operations. The equipment shall be regularly inspected and maintained in good condition for use. The equipment and the location of land bases shall be approved by the supervisor. The operator shall notify the supervisor of the location at which such equipment is located for operations conducted on or for each lease. All changes in location and equipment maintained at each location shall be approved by the supervisor.

ROBERT F. EVANS, *Supervisor.*

Approved: August 28, 1969

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 8, Oct. 30, 1970]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA—APPROVAL PROCEDURES FOR INSTALLATION AND OPERATION OF PLATFORMS, FIXED AND MOBILE STRUCTURES, AND ARTIFICIAL ISLANDS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(a). Section 250.19(a) provides as follows:

"(*a*) The Supervisor is authorized to approve the design, other features, and plan of installation of all platforms, fixed structures, and artificial islands as a condition of the granting of a right of use or easement under Paragraphs (a) and (b) of Section 250.18 or authorized under any lease issued or maintained under the Act."

The operator shall be responsible for compliance with the requirements of this Order in the installation and operation of all platforms, fixed and mobile structures, and artificial islands, including all facilities installed on a platform or structure whether or not operated or owned by the operator. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. The following requirements are applicable to all platforms approved and installed subsequent to the effective date of this Order, and to all platforms when structural and equipment modifications are to be made:

A. General Design.—The design of platforms, fixed structures, and artificial islands shall include consideration of such factors as water depth, surface and subsurface soil conditions, wave and current forces, wind forces, total equipment weight, and other pertinent geological, geographical, environmental, and operational conditions.

B. *Application.*—The operator shall submit, in duplicate, the following to the appropriate District Office for approval:

(1) *Design Features.*—Information relative to design features on an 8" x 10½" plat or plats showing the platform dimensions, plan and tow elevations, number and location of well slots, and water depth. In addition, the plat shall include:

(*a*) Nominal size and thickness range of piling.
(*b*) Nominal size and thickness range of jacket column leg.
(*c*) Nominal size and thickness range of deck column leg.
(*d*) Design piling penetration.
(*e*) Maximum bearing and lateral load per pile in tons.
(*f*) Identification data which shall be the lease number, block number, area, and operator.
(*g*) The following certification signed and dated with the title of the company representative:

"(Operator) certifies that this platform has been certified by a registered professional engineer and that the structure will be constructed, operated, and maintained as described in the application, and any approved modification thereto. Certified plans are on file at————."

(2) *Non-design Features.*—Information relative to nondesign features including the following:

(*a*) Primary use intended, including drilling, production of oil and gas, sulphur, or salt.

(*b*) Personnel and personnel transfer facilities including living quarters, boat landings, and heliport.

(*c*) Type of deck, such as steel or wood, and whether coated with protective material.

(*d*) Method of protection from corrosion.

(*e*) Production facilities including separators, treaters, storage tanks, compressors, line pumps, and metering devices, except that when initially designed and utilized for drilling, this information may be submitted prior to installation.

(*f*) Safety and pollution control equipment and features.

(*g*) Other information when required.

C. *Certified Plan.*—Detailed structural plans certified by a registered professional engineer shall be on file and maintained by the operator or his designee.

2. *Safety and Pollution Control Equipment and Procedures*

A. The following requirements shall apply to all platforms. Operators of platforms installed prior to the effective date of this Order shall comply with the requirements of subparagraphs (1)(a) through (f), (2), and (3) within three months, with subparagraphs (1)(g) and (4) within six months, and which subparagraphs (5), (6), (7), (8), and (9) within one year, from the effective date of this Order.

(1) The following shut-in devices shall be installed and maintained in an operating condition on all pressurized vessels and water separation facilities when such vessels and separation facilities are in service. The operator shall submit records to the appropriate District Office semi-annually showing the present status and past history of each device including dates and details of inspection, testing, repairing, adjustment, and reinstallation.

(*a*) All separators shall be equipped with high-low pressure shut-in sensors, low level shut-in controls, and a relief valve. High liquid level control devices shall be installed when the vessel can discharge to a flare.

(*b*) All pressure surge tanks shall be equipped with a high and low pressure shut-in sensor, a high level shut-in control, flare line, and relief valve.

(*c*) Atmospheric surge tanks shall be equipped with a high level shut-in sensor.

(*d*) All other hydrocarbon handling pressure vessels shall be equipped with high-low pressure shut-in sensors, high-low level shut-in controls, and relief valves, unless determined to be otherwise protected.

(*e*) Pilot-operated pressure relief valves shall be equipped to permit testing with an external pressure source. Spring-loaded pressure relief valves shall either be bench-tested or equipped to permit testing with an external pressure source. A relief valve shall be set no higher than the designed working pressure of the vessel. The high pressure shut-in sensor shall be set no higher than 5% below the rated or designed working pressure and the low pressure shut-in sensor shall be set no lower than 10% below the lowest pressure in the operating pressure range on all vessels with a rated or designed working pressure of more than 400 psi. On lower pressure vessels the above percentages shall be used as guidelines for sensor settings considering pressure and operating conditions involved; except that sensor settings shall not be within 5 psi of the rated or designed working pressure or the lowest pressure in the operating pressure range.

(*f*) All sensors shall be equipped to permit testing with an external pressure source.

(*g*) All flare lines shall be equipped with a scrubber or similar separation equipment.

(2) The following remote and local automatic shut-in devices shall be installed and maintained in an operating condition at all times when the affected well (or wells) is producing. The operator shall submit records to the appropriate District Office semi-annually showing the present status and past history of each such device including dates and details of inspection, testing, repairing, adjustment, and reinstallation.

(*a*) All wellhead assemblies shall be equipped with an automatic fail-close valve. Automatic safety valves temporarily out of service shall be flagged.

(*b*) All flowlines from wellheads shall be equipped with high-low pressure sensors located close to the wellhead. The pressure sensors shall be set to activate the wellhead valve in the event of abnormal pressures in the flowline.

(*c*) All headers shall be equipped with check valves on the individual flowlines. The flowline and valves from each well located upstream of, and including, the header valves shall withstand the shut-in pressure of that well, unless protected by a relief valve with connections to bypass the header. If there is an inlet valve to a separator, the valve, flowline, and all equipment upstream of the valve shall also withstand shut-in wellhead pressure, unless protected by a relief valve with connections to bypass the header.

(*d*) All pneumatic shut-in control lines shall be equipped with fusible material at strategic points.

(*e*) Remote shut-in controls shall be located on the helicopter deck and all exit stairway landings, including at least one on each boat landing. These controls shall be quick-opening valves.

(*f*) All pressure sensors shall be tested for proper pressure settings monthly for at least four months. At such time as the monthly results are consistent, a quarterly test shall be required for at least one year. If these results are consistent, a longer period of time between testing may then be approved by the Supervisor. In the event any testing sequence reveals inconsistent results, the monthly testing sequence shall be re-instituted. Results of all tests shall be recorded and maintained in the field.

(*g*) All automatic wellhead safety valves shall be tested for operation weekly. All automatic wellhead safety valves shall be tested for holding pressure monthly. If these results are consistent, a longer period of time between pressure tests, not to exceed quarterly, may then be approved by the Supervisor. In the event that any pressure testing sequence, exceeding monthly, reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained in the field.

(*h*) Check valves shall be tested for holding pressure monthly for at least four months. At such time as the monthly results are satisfactory, a quarterly test shall be required for at least one year. If these results are consistent, a longer period of time between testing may then be approved by the Supervisor. In the event any testing sequence reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained in the field.

(*i*) A complete testing and inspection of the safety system shall be witnessed by Geological Survey representatives at the time production is commenced. Thereafter, the operator shall arrange for a test every six months. The test shall be conducted when it can be witnessed by Geological Survey representatives.

(*j*) A standard procedure for testing of safety equipment shall be prepared and posted in a prominent place on the platform.

(3) Curbs, gutters, and drains shall be condstructed in all deck areas in a manner necessary to collect all contaminants, unless drip pans or equivalent are placed under equipment and piped to a sump which will automatically maintain the oil at a level sufficient to prevent discharge of oil into the Gulf waters. Alternate methods to obtain the same results will be acceptable. These systems shall not permit spilled oil to flow into the wellhead area.

(4) An auxiliary electrical power supply shall be installed to provide emergency power capable of operating all electrical equipment required to maintain safety of operation in the event the primary electrical power supply fails.

(5) The following requirements shall apply to the handling and disposal of all produced waste water discharged into the Gulf of Mexico. The disposal of waste water other than into the Gulf waters shall have the method and location approved by the Supervisor.

(*a*) Water discharged shall not create conditions which will adversely affect the public health or the use of the waters for the propagation of aquatic life, recreation, navigation, or other legitimate uses.

(b) Waste water disposal systems shall be designed and maintained to reduce the oil content of the disposed water to an average of not more than fifty ppm. An effluent sampling station shall be located at a point prior to discharge into the receiving waters where a representative sample of the treated effluent can be obtained. On one day each month four effluent samples shall be taken within a 24-hour period and determinations shall be made on the temperature, suspended solids, settleable solids, pH. total oil content, and volume of sample obtained.

All samples shall be taken and all analyses for oil content shall be performed in accordance with the American Society for Testing and Materials test D1340, "Oily Matter in Industrial Waste Water". The Supervisor may approve different methods for determination of oil content if the method to be used is indicated to be reliable. No effluent containing in excess of one hundred ppm of total oil content shall be discharged into the Gulf of Mexico. A written report of the results shall be furnished to the Regional Office annually. The report shall contain dates, time and location of sample, volumes of waste discharge on the date of sampling in barrels per day, and the results of the specific analysis and physical observations.

(6) A firefighting system shall be installed and maintained in an operating condition in accordance with the following:

(a) A fixed automatic water spray system shall be installed in all inadequately ventilated wellhead areas as these areas are defined in Paragraph 9 API RP 500A. These systems shall be installed in accordance with the most current edition of National Fire Protection Association's Pamphlet No. 15.

(b) A firewater system of rigid pipe with fire hose stations shall be installed and may include a fixed spray system. Such a system shall be installed in a manner necessary to provide needed protection in areas where production handling equipment is located. A firefighting system using chemicals may be considered for installation in certain platform areas in lieu of a firewater system in that area, if determined to provide equivalent fire protection control.

(c) Pumps for the firewater systems shall be inspected and test-operated weekly. A record of the tests shall be maintained in the field and submitted semi-annually to the appropriate District Office. An alternate fuel or power source shall be installed to provide continued pump operation during platform shutdown unless an alternate firefighting system is provided.

(d) Portable fire extinguishers shall be located in the living quarters and in other strategic areas.

(e) A diagram of the firefighting system showing the location of all equipment shall be posted in a prominent place on the platform and copy submitted to the appropriate District Office.

(7) An automatic gas detector and alarm system shall be installed and maintained in an operating condition in accordance with the following:

(a) Gas detection systems shall be installed in all enclosed areas containing gas handling facilities or equipment and in other enclosed areas which are classified as hazardous areas as defined in API RP 500 and the most current edition of the National Electric Code.

(b) All gas detection systems shall be capable of continuously monitoring for the presence of combustible gas in the areas in which the detection devices are located.

(c) The central control shall be capable of giving an alarm at some point below the lower explosive limit of 1.3% as shown in the Bureau of Mines Bulletin No. 503. This low level shall be for alarm purposes only.

(d) A high level setting of not more than 4.9% shall be used for shut-in sequences and the operation of emergency equipment.

(e) An application for the installation and maintenance of any gas detection system shall be filed with the appropriate District Office for approval. The application shall include the following:

(i) Type, location, and number of detection or sampling heads.

(ii) Cycling, noncycling, and frequency information.

(iii) Type and kind of alarm including emergency equipment to be activated.

(iv) Method used for detection of combustible gas.

(v) Method and frequency of calibration.

(vi) A diagram of the gas detection system.

(vii) Other pertinent information.

(f) A diagram of the gas detection system showing the location of all gas detection points shall be posted in a prominent place on the platform.

(8) The following requirements shall be applicable to all electrical equipment and systems installed:

(a) All engines shall be equipped with low-tension ignition systems containing rigid connections and shielded wiring which shall prevent the release of sufficient electrical energy under normal or abnormal conditions to cause ignition of a combustible mixture.

(b) All electrical generators, motors, and lighting systems shall be installed, protected, and maintained in accordance with the most current edition of the National Electric Code and API RP 500A and B, as appropriate.

(c) Marine-armored cable or metal-clad cable may be substituted for wire in conduit in any area.

(9) Sewerage disposal systems shall be installed and used in all cases where sewage is discharged into the Gulf of Mexico. Sewage is defined as human body wastes and the wastes from toilets and other receptacles intended to receive or retain body wastes. Following sewage treatment, the effluent shall contain 50 ppm or less of biochemical oxygen demand (BOD), 150 ppm or less of suspended solids, and shall have a minimum chlorine residual of 1.0 mg/liter after a minimum retention time of fifteen minutes.

(B) The requirements of subparagraphs 2.A(3), (4), (8), and (9) shall apply to all mobile drilling structures used to conduct drilling or workover operations on Federal leases in the Gulf of Mexico.

ROBERT F. EVANS, *Supervisor.*

Approved: October 30, 1970.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 9, Oct. 30, 1970]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA—APPROVAL PROCEDURE FOR OIL AND GAS PIPELINE

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(b). Section 250.19(b) provides as follows:

"(b) The Supervisor is authorized to approve the design, other features, and plan of installation of all pipelines for which a right of use or easement has been granted under Paragraph (c) of Section 250.18 or authorized under any lease issued or maintained under the Act, including those portions of such lines which extend onto or traverse areas other than the Outer Continental Shelf."

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. *General Design*

All pipelines shall be designed and maintained in accordance with the following:

A. The operator shall be responsible for the installation of the following control devices on all oil and gas pipelines connected to a platform including pipelines which are not operated or owned by the operator. Operators of platforms installed prior to the effective date of this Order shall comply with the requirements of subparagraphs (1) and (2) within six months of the effective date of this Order. The operator shall submit records semi-annually showing the present status and past history of each device, including dates and details of inspection, testing, repairing, adjustment, and reinstallation.

(1) All oil and gas pipelines leaving a platform receiving production from the platform shall be equipped with a high-low pressure sensor to directly or indirectly shut-in the wells on the platform.

(2) (*a*) All oil and gas pipelines delivering production to production facilities on a platform shall be equipped with an automatic shut-in valve connected to the platform's automatic and remote shut-in system.

(*b*) All oil and gas pipelines coming onto a platform shall be equipped with a check valve to avoid backflow.

(*c*) Any oil or gas pipelines crossing a platform which do not deliver production to the platform, but which may or may not receive production from the platform, shall be equipped with high-low pressure sensors to activate an automatic shut-in valve to be located in the upstream portion of the pipeline at the platform. This automatic shut-in valve shall be connected to either the platform automatic and remote shut-in system or to an independent remote shut-in system.

(*d*) All pipeline pumps shall be equipped with high-low pressure shut-in devices.

B. All pipelines shall be protected from loss of metal by corrosion that would endanger the strength and safety of the lines either by providing extra metal for corrosion allowance, or by some means of preventing loss of metal such as protective coatings or cathodic protection.

C. All pipelines shall be installed and maintained to be compatible with trawling operations and other uses.

D. All pipelines shall be hydrostatically tested to 1.25 times the designed working pressure for a minimum of 2 hours prior to placing the line in service.

E. All pipelines shall be maintained in good operating condition at all times and inspected monthly for indication of leakage using aircraft, floating equipment, or other methods. Records of these inspections including the date, methods, and results of each inspection shall be maintained by the pipeline operator and submitted annually by April 1. The pipeline operator shall submit records indicating the cause, effect, and remedial action taken regarding all pipeline leaks within one week following each such occurrence.

F. All pipelines shall be designed to be protected against water currents, storm scouring, soft bottoms, and other environmental factors.

2. *Application*

The operator shall submit in duplicate the following to the Supervisor for approval:

A. Drawing on 8″ x 10½″ plat or plats showing the major features and other pertinent data including: (1) water depth, (2) route, (3) location, (4) length, (5) connecting facilities, (6) size, and (7) burial depth, if buried.

B. A schematic drawing showing the following pipeline safety equipment and the manner in which the equipment functions: (1) high-low pressure sensors, (2) automatic shut-in valves, and (3) check valves.

C. General information concerning the pipeline including the following:

(1) Product or products to be transported by the pipeline.
(2) Size, weight, and grade of the pipe.
(3) Length of line.
(4) Maximum water depth.
(5) Type or types of corrosion protection.
(6) Description of protective coating.
(7) Bulk specific gravity of line (with the line empty).
(8) Anticipated gravity or density of the product or products.
(9) Design working pressure and capacity.
(10) Maximum working pressure and capacity.
(11) Hydrostatic pressure and hold time to which the line will be tested after installation.
(12) Size and location of pumps and prime movers.
(13) Any other pertinent information as the Supervisor may prescribe.

3. *Completion Report*

The operator shall notify the Supervisor when installation of the pipeline is completed and submit a drawing on 8″ x 10½″ plats showing the location of the line as installed, accompanied by all hydrostatic test data including procedure, test pressure, hold time, and results.

ROBERT F. EVANS, *Supervisor.*

Approved: October 30, 1970.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 10, Aug. 28, 1969]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL SULPHUR LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA—SULPHUR DRILLING PROCEDURES OFF LOUISIANA AND TEXAS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.34, 250.41, and 250.91. All exploratory core holes for sulphur and all sulphur development wells shall be drilled in accordance with the provisions of this Order, except that development wells shall be drilled in accordance with field rules when established by the supervisor. Each Application to Drill (Form 9–331C) shall include all information required under 30 CFR 250.91 and the integrated casing, cementing, mud, and blowout prevention program for the well. The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. Well Casing and Cementing

All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). Special consideration to casing design shall be given to compensate for effects caused by subsidence, corrosion, and temperature variation. All depths refer to true vertical depth (TVD).

A. *Drive or Structural Casing.*—This casing shall be set by drilling, driving, or jetting to a minimum depth of 100 feet below the Gulf floor, or to such greater depth required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the Gulf, and a quantity of cement sufficient to fill the annular space back to the Gulf floor must be used.

B. *Conductor Casing.*—This casing shall be set and cemented before drilling into shallow formations known to contain hydrocarbons or, if unknown, upon encountering such formations. Conductor casing shall extend to a depth of not less than 350 feet nor more than 750 feet below the Gulf floor. A quantity of cement sufficient to fill the annular space back to the Gulf floor must be used. The cement may be washed out or displaced to a depth of 40 feet below the Gulf floor to facilitate casing removal upon well abandonment.

C. *Caprock Casing.*—This casing shall be set at the top of the caprock and be cemented with a quantity of cement sufficient to fill the annular space back to the Gulf floor. Stage cementing or other cementing method shall be used to insure cement returns to the Gulf floor.

2. Blowout Prevention Equipment

Blowout preventers and related well control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the conductor casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed, as follows:

A. *Conductor Casing.*—Before drilling below this string, at least one remotely controlled bag-type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. To avoid formation fracturing from complete shut-in of the well, a large diameter pipe with control valves shall be installed on the conductor casing below the blowout preventer so as to permit the diversion of hydrocarbons and other fluids; except that when the blowout preventer assembly is on the Gulf floor, the choke and kill lines shall be equipped to permit the diversion of hydrocarbons and other fluids.

B. *Caprock Casing.*—Before drilling below this string, the blowout prevention equipment shall include a minimum of: (1) three remotely controlled, hydraulically operated, blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one bag-type; (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke manifold; (4) a kill line; and (5) a fill-up line.

C. *Testing.*—Ram-type blowout preventers and related control equipment shall be tested with water to the rated working pressure of the stack assembly, or to the working pressure of the casing, whichever is the lesser, (1) when installed; (2) before drilling out after each string of casing is set; (3) not less than once each week while drilling; and (4) following repairs that require disconnecting a pressure seal in the assembly. The bag-type blowout preventer shall be tested to 70 percent of the above pressure requirements.

While drill pipe is in use ram-type blowout preventers shall be actuated to test proper functioning once each day. The bag-type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a pressure capacity reserve at all times to provide for repeated operation of hydraulic preventers. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded on the driller's log.

D. *Other Equipment.*—A drill string safety value in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Separate valves shall be maintained on the rig floor to fit all pipe in the drill string. A Kelly cock shall be installed below the swivel.

3. Mud Program—General

The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times. The following mud control and testing equipment requirements are applicable to operations conducted prior to drilling below the caprock casing.

A. *Mud Control.*—Before starting out of the hole with drill pipe, the mud shall be circulated with the drill pipe just off bottom until the mud is properly conditioned. When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops below 100 feet, and a mechanical device for measuring the amount of mud required to fill the hole shall be utilized. The volume of mud required to fill the hole shall be watched, and any time there is an indication of swabbing, or influx of formation fluids, the drill pipe shall be run to bottom, and the mud properly conditioned. The mud shall not be circulated and conditioned except on or near bottom, unless well conditions prevent running the pipe to bottom.

B. Mud Testing and Equipment.—Mud testing equipment shall be maintained on the drilling platform at all times, and mud tests shall be performed daily, or more frequently as conditions warrant.

The following mud system monitoring equipment must be installed (with derrick floor indicators) and used throughout the period of drilling after setting and cementing the conductor casing:

(1) Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual or audio warning device.

(2) Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.

(3) Mud return indicator to determine that returns essentially equal the pump discharge rate.

ROBERT F. EVANS, *Supervisor*

Approved: August 28, 1969.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 11, Apr. 5, 1972]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS,
GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA—INTERIM OIL AND GAS PRODUCTION RATES

This Interim Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.16 and supersedes Interim OCS

Order No. 11, dated December 11, 1970, and the first and second revisions thereof, dated February 11, 1971, and March 29, 1971, respectively. The provisions of this Interim Order and the maximum production rates heretofore approved under Interim Order No. 11, dated December 11, 1970, will remain in full force and effect until superseded, amended, or terminated. 30 CFR 250.10 provides as follows:

"*Well potentials and permissible flow.*—The supervisor is authorized to specify the time and method for determining the potential capacity of any well and to fix, after appropriate notice, the permissible production of any such well that may be produced when such action is necessary to prevent waste or to conform with such proration rules, schedules, or procedures as may be established by the Secretary."

In accordance with the notice appearnig in the Federal Register, dated December 5, 1970 (35 F.R. 18559), the provisions of this Order are applicable to all oil and gas wells located on the Outer Continental Shelf of the Gulf of Mexico off the State of Texas and the undisputed areas off the State of Louisiana; provided, however, this order shall not apply to any wells on oil and gas leases situated landward of the line, or transected by the line, described in paragraph 3 of the Supplemental Decree entered December 20, 1971, in *United States* v. *Louisiana*, S. Ct. No. 9, Original (40 L.W. 3287). Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12 (b).

1. Maximum Production Rates

A. Producible Wells.—Effective May 1, 1972, all producible oil and gas wells and reservoirs may be produced at daily rates not to exceed the Maximum Efficient Rate (MER), subject to the limitations set forth in paragraph 5 below.

B. New Completions and Recompletions.—New oil and gas well completions and recompletions shall be produced at a rate established by the Supervisor. A testing period not to exceed 30 days will be allowed prior to setting the maximum production rate for the well. At the end of the testing period, the operator shall submit a detailed determination of the MER justifying a proposed maximum rate of production for the Supervisor's approval. The initial production test of all completions and recompletions may be witnessed by a representative of the Supervisor.

2. Definition of MER.

The MER is defined as that rate for each reservoir and each well which, if exceeded, would lead to avoidable underground waste through loss of ultimate recovery of oil and gas from that reservoir. It is dependent on the recovery mechanism operative for the current producing period, and is based on engineering and geological information.

3. Determination of MER.

On or before May 1, 1972, each operator shall submit reports, for approval by the Supervisor, showing the operator's estimate of the MER for each oil and gas well and reservoir on those leases in the area removed from dispute in *United States* v. *Louisiana*, S. Ct. No. 9, Original, by entry of the Supplemental Decree of December 20, 1971, in that litigation (40 L.W. 3287). Reports shall be identified by the name of the field, the OCS lease number, the well number, and the designation and depth of the productive zone. As soon as available and prior to July 1, 1972, each operator shall submit the technical information and methods used to determine the MER applicable to each well and reservoir.

Revisions in the operator's estimate of the MER for oil and gas wells and reservoirs located on leases subject to this Interim Order shall be submitted to the Supervisor for approval.

4. Reports

Each operator shall submit the following reports for each lease separately to the Regional Office. Initial reports for those leases in the area removed from dispute, referred to in Paragraph 3 above, shall be for the month of April 1972 for the reports required in A, C, and D, below, and for the quarter ending April 1, 1972, for the report required in B below.

A. A monthly well potential report on a form identical to the Louisiana Department of Conservation Form DM-1R. This report shall be submitted for each month by the 10th day of each succeeding month.

B. A gas well deliverability test report on a form identical to the Louisiana Department of Conservation Form DT–1, shall be submitted by January 1, April 1, July 1, and October 1.

C. A monthly producer's crude oil and/or condensate report on a form identical to Louisiana Department of Conservation Form R–1. This report shall be submitted for each month by the 25th day of each succeeding month.

D. A monthly producer's natural gas report on a form identical to Louisiana Department of Conservation Form R–5P. This report shall be submitted for each month by the last day of each succeeding month.

5. Limitations on Production

A. Production rates shall not result in venting or flaring of gas in violation of the Operating Regulations in 30 CFR 250.30.

B. In order to provide safe operating conditions and prevent pollution, oil and gas production rates shall not exceed the operating capacity of production, transportation, and storage facilities, including, but not limited to, separators, dehydrators, compressors, surge tanks, and pipelines. All producing operations shall be in accordance with the provisions of OCS Orders Nos. 5, 7, 8 and 9. Production rates shall be maintained at a level to permit efficient operation of subsurface safety devices.

ROBERT F. EVANS, *Supervisor.*
RUSSELL G. WAYLAND,
Chief, Conservation Division.

Approved: April 5, 1972

[OCS Order No. 12, Aug. 13, 1972]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, GULF OF MEXICO AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA—PUBLIC INSPECTION OF RECORDS

This Interim Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.97 and 43 CFR 2.2. Section 250.97 of 30 CFR provides as follows:

"*Public Inspection of Records.*—Geological and geophysical interpretations, maps, and data required to be submitted under this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect or until such time as the supervisor determines that release of such information is required and necessary for the proper development of the field or area."

Section 2.2 of 43 CFR provides in part as follows:

"*Determinations as to Availability of Records.*—(*a*) Section 552 of Title 5, U.S. Code, as amended by Public Law 90–23 (the act codifying the "Public Information Act") requires that identifiable agency records be made available for inspection. Subsection (b)[1] of section 552 exempts several categories of records from the general requirement but does not require the withholding from inspection of all records which may fall within the categories exempted. Accordingly, no request made of a field office to inspect a record shall be denied unless the head of the office or such higher field authority as the head of the bureau may designate shall determine (1) that the record falls within one or more of the categories exempted and (2) either that disclosure is prohibited by statute or Executive Order or that sound grounds exist which require the invocation of the exemption. A request to inspect a record located in the headquarters office or a bureau shall not be denied except on the basis of a similar determination made by the head of the bureau or his designee, and a request made to inspect a record located in a major organizational unit of the Office of the Secretary shall not be denied except on the basis of a similar determination by the head of that unit.

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[1] Subsection (b) of section 552 provides that:
"(b) This section does not apply to matters that are—
"* * *
"(4) Trade secrets and commercial or financial information obtained from a person and privileged or confidential;
"* * *
"(9) Geological and geophysical information and data, including maps, concerning wells."

Officers and employees of the Department shall be guided by the "Attorney General's Memorandum on the Public Information Section of the Administrative Procedure Act" of June 1967.

"(*b*) An applicant may appeal from a determination that a record is not available for inspection to the Solicitor of the Department of the Interior, who may exercise all of the authority of the Secretary of the Interior in this regard. The Deputy Solicitor may decide such appeals and may exercise all of the authority of the Secretary in this regard."

The operator shall comply with the requirements of this Order. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. *Availability of Records Filed on or after December 1, 1970.*

It has been determined that certain records pertaining to leases and wells in the Outer Continental Shelf and submitted under 30 CFR 250 shall be made available for public inspection, as specified below, in the Area office, Metairie, Louisiana.

A. Form 9-152—Monthly Report of Operations.—All information contained on this form shall be available except the information required in the Remarks column.

B. Form 9-330—Well Completion of Recompletion Report and Log.—(1) Prior to commencement of production all information contained in this form shall be available except Item 1a, Type of Well; Item 4, Location of Well, At top prod. interval reported below; Item 22, If Multiple Compl., How many; Item 24, Producing Interval; Item 26, Type Electric and Other Logs Run; Item 28, Casing Record; Item 29, Liner Record; Item 30, Tubing Record; Item 31, Perforation Record, Item 32, Acid, Shot, Fracture, Cement Squeeze, etc.; Item 33, Production; Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(2) After commencement of production all information shall be available except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(3) If production has not commenced after an elapsed time of five years from the date of filing Form 9-330 as required in 30 CFR 250.38(b), all information contained on this form shall be available except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers. Within 90 days prior to the end of the five-year period the lessee or operator may submit objections to the release of such information. The supervisor, taking into consideration the objections of the lessee, proximity to unleased lands, and the best interests of the United States, may determine that such information shall not be released.

C. Form 9-331—Sundry Notices and Report on Wells.—(1) When used as a "Notice of Intentions to" conduct operations, all information contained on this form shall be available except Item 4, Location of Well, At top prod. interval; and Item 17, Describe Proposed or Completed Operations.

(2) When used as a "Subsequent Report of" operations, and after commencement of production, all information contained on this form shall be available except information under Item 17 as to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.

D. Form 9-331C—Application for Permit to Drill, Deepen or Plug Back.—All information contained on this form, and location plat attached thereto, shall be available except Item 4, Location of Well, At proposed prod. zone; and Item 23, Proposed Casing and Cementing Program.

E. Sales of Lease Production.—Information contained on monthly Geological Survey computer printout showing sales of production of oil, condensate, gas and liquid products, by lease, shall be made available.

2. *Filing of Reports*

All reports on Forms 9-152, 9-330, 9-331, and 9-331C shall be filed in accordance with the following:

A. All reports submitted on these forms after the effective date of this Order shall be filed in two separate sets. All items on the forms in one set shall be completed in full and such forms, and all attachments thereto, shall not be available for public inspection. The additional set shall be completed in full, except that the items described in 1.(A), (B), (C), and (D) above, and the attachments relating to such items, may be excluded. The words

"Public Information" shall be shown on the lower right-hand corner of this set. This additional set shall be made available for public inspection.

B. Copies of reports on these forms which were filed between December 1, 1970, and the effective date of this Order, shall be resubmitted (in duplicate or triplicate, as provided by the regulations) within 30 days after the effective date of this Order. These reports may exclude the items described in 1. (A), (B), (C), and (D) above, and shall show the words "Public Information" on the lower right-hand corner and shall be made available for public inspection.

3. *Availability of Records Filed Prior to December 1, 1970.*

Information filed prior to December 1, 1970, on the forms referred to in (1) above, is not in a form which can be readily made available for public inspection. Requests for information on these forms shall be submitted to the supervisor in writing and shall be made available in accordance with 43 CFR Part 2.

ROBERT F. EVANS, *Supervisor.*

Approved: August 13, 1971

RUSSELL G. WAYLAND,
Chief, Conservation Division.

APPENDIX XVIII. NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF PACIFIC REGION

[OCS Order No. 1, June 1, 1971]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATION'S, PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION—MARKING OF WELLS, PLATFORMS, AND FIXED STRUCTURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.37. Section 250.37 provides as follows: "*Well designations.*—The lessee shall mark promptly each drilling platform or structure in a conspicuous place, showing his name or the name of the operator, the serial number of the lease, the identification of the wells, and shall take all necessary means and precautions to preserve these markings."

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. *Identification of Platforms or Fixed Structures*

Platforms and structures shall be identified at two diagonal corners of the platform or structure by a sign with letters and figures not less than 12 inches in height with the following information: the name of lease operator, the OCS lease number and the platform or structure designation. The information shall be abbreviated as in the following example: "The Blank Oil Company operates 'C' platform on lease OCS P 0000".

The identifying sign on the platform would show: "BOC-OCS-P 0000-C".

2. *Identification of Non-Fixed Platforms or Structures*

Floating semi-submersible platforms, bottom-setting mobile and floating drilling ships shall be identified by one sign with letters and figures not less than 12 inches in height affixed to the derrick to be visible from off the vessel with the following information: the name of the lease operator and the OCS lease number.

3. *Identification of Individual Wells on Platforms*

The OCS lease and well number shall be painted on, or a sign affixed to, each singly completed well. In multiple completed wells each completion shall be individually identified at the wellhead. All identifying signs shall be maintained in a legible condition.

D. W. SOLANAS, *Supervisor.*

Approved: June 1, 1971.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 2, June 1, 1971]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION—DRILLING PROCEDURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.34, 250.41 and 250.91. All exploratory wells drilled for oil and gas shall be drilled in accordance with the provisions of this Order. Initial development wells drilled for oil and gas shall be drilled in accordance with the provisions of this Order, and these provisions shall continue in effect until field rules are issued. After field rules have been established by the Supervisor, development wells in the individual fields shall be drilled in accordance with such rules.

Where sufficient geologic and engineering information is obtained through exploratory drilling, operators may make application to the Supervisor for the establishment of field rules, but such applications shall be made before more than five development wells have been drilled in a field. When required by the Supervisor, operators shall make application for the establishment of field rules for existing fields containing more than five development wells on the date of this Order.

Each Application to Drill (Form 9-331C) for exploratory wells and development wells not covered by field rules shall include all information required under 30 CFR 250.91 and the detailed casing, cementing, mud, and blowout prevention program for the well and shall comply with the following requirements. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Well Casing

All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). The Application to Drill (Form 9-331C) shall contain a statement that all zones which contain oil, gas, or fresh water shall be fully protected by casing and cement. All casing strings shall be new pipe or equivalent. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural casing, conductor casing, surface casing, intermediate casing, protective casing, and production casing. These casing strings shall be run and cemented prior to drilling below the specified setting depths, subject to minor variations to permit the casing to be set in a competent bed. All depths refer to true vertical depth (TVD) below the ocean floor, unless otherwise specified. Determination of proper casing setting depths shall be based upon all geological and engineering factors including the presence or absence of hydrocarbons. Formation fracture gradients and formation pressures shall be taken into account.

A. Drive or Structural Casings.—This casing shall be set by drilling, driving, or jetting to a depth of approximately 100 feet below the ocean floor to support unconsolidated deposits and to provide hole stability for initial drilling operations. If drilled in, the drilling fluid shall be a type that will not pollute the ocean. This casing may be omitted, when approved by the Supervisor, if there is geological evidence that hydrocarbons will not be encountered while drilling the hole for the conductor casing and is not needed for hole stability.

B. Conductor Casing.—This casing shall be set at a minimum depth of 300 feet or a maximum depth of 500 feet below the ocean floor; provided, however, the conductor casing shall be set before drilling into shallow formation known to contain oil or gas or, if unknown, upon encountering such formations.

C. Surface Casing.—This casing shall be set at a minimum depth of 1,000 feet or a maximum depth of 1,200 feet below the ocean floor, but may be set as deep as 1,500 feet in the event the conductor casing is set at least 450 feet below the ocean floor.

D. Intermediate Casing.—This casing shall be set if the proposed total depth of the well is greater than 3,500 feet (TVD in feet from rotary table). When surface casing is set at 1,500 feet the intermediate casing may be omitted if the proposed total depth of the well is not greater than 4,500 feet. Otherwise, the intermediate casing shall be set before drilling below the setting depths specified in the following table:

	Setting depths for intermediate casing (TVD in feet below ocean floor)	
	Minimum	Maximum
Proposed total depth of well or proposed depth of 1st full string of protective casing (TVD in feet from rotary table):		
3,500 to 4,500	1,500	3,500
4,500 to 6,000	1,750	3,500
6,000 to 9,000	2,250	3,500
9,000 to 11,000	2,750	3,500
11,000 to 13,000	3,250	3,500
13,000 or below	3,450	3,550

E. Protective Casing.—When required by well conditions, this casing shall be set at any time when drilling below the surface casing. If a liner is used as a protective string, the lap shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and next larger string has been achieved. The test shall be recorded on the driller's log and shall be witnessed by a Geological Survey representative.

F. Production Casing.—This casing shall be set before completing the well for production. When a blank or combination liner is run and cemented as production casing, the testing of the lap between the liner top and next larger string shall be conducted as in the case of protective liners. The surface casing shall never be used as production casing.

G. Casing Cementing.—The structural (if drilled or jetted), conductor, and surface casings shall be cemented with a quantity sufficient to fill the annular space back to the ocean floor. The intermediate casing shall be cemented with a quantity sufficient to fill the annular space back to the ocean floor or at least 100 feet into the next larger string of pipe. The protective casing shall be cemented so that all hydrocarbon zones and abnormal pressure intervals are isolated. The production casing shall be cemented in a manner necessary to cover or isolate all zones which contain hydrocarbons and abnormal pressure intervals but in any case, a calculated volume sufficient to fill the annular space at least 500 feet above the uppermost hydrocarbon zone, not previously cased, must be used. Whenever there are indications of improper cementing, such as lost circulation, cement channeling, or mechanical failure of equipment, a temperature or cement bond survey shall be run, either before or after remedial cementing, to aid in determining whether the casing is properly cemented. If the annular space is not adequately cemented by the primary operation, the operator shall either (1) recement, (2) squeeze the shoe of the casing with cement, either by drilling out and squeezing or by squeezing through perforations at the interval of competent formation nearest the shoe, or (3) displace with cement in sufficient quantity to fill the annular space. Upon determining that the casing shoe has been adequately cemented the operator may commence further drilling operations provided that prior to abandonment of the well the annular space behind the conductor, surface, and intermediate casings shall be cemented back to the ocean floor or 100 feet into the next larger string of pipe.

H. Pressure Testing.—Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure tested as shown in the table below. This test shall not exceed the rated working pressure of the casing. If the pressure declines more than 10 percent in 30 minutes, or if there is other indication of a leak, corrective measures must be taken until a satisfactory test is obtained.

Casing string and minimum pressure test (psi)

Conductor, 200.
Surface and intermediate, 1,000.
Protective, 1,500 or 0.2 psi/ft., whichever is greater.
Liner, 1,500 or 0.2 psi/ft., whichever is greater.
Production, 1,500 or 0.2 psi/ft., whichever is greater.

After cementing any of the above strings, drilling shall not be commenced until a time lapse of:

(1) 24 hours, or

(2) 8 hours under pressure for the conductor casing string and 12 hours under pressure for all other casing strings. (Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure are used.)

All casing pressure tests shall be recorded on the driller's log.

2. Blowout Prevention Equipment

Blowout preventers and related well control equipment shall be installed, used, and tested in a manner necessary to prevent blowouts. Prior to drilling below the conductor casing, blowout prevention equipment shall be installed and maintained ready for use until drilling operations are completed as follows:

A. Conductor Casing.—Before drilling below this string, at least one remotely controlled hydril type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. To avoid formation fracturing from complete shut-in of the well, a pipe of adequate diameter, with control valves shall be installed below the blowout preventer so as to permit the diversion of hydrocarbons and other fluids; except that when the blowout preventer assembly is on the ocean floor, the choke and kill lines shall be equipped to permit the diversion of hydrocarbons and other fluids.

B. Surface Casing.—Before drilling below this string the blowout prevention equipment shall include a minimum of:

(1) three remotely controlled hydraulically operated blowout preventers with a rated working pressure which exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams, and one hydril type;

(2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body;

(3) a choke manifold;

(4) a kill line; and

(5) a fill-up line.

C. Intermediate Casing.—Before drilling below this string the blowout prevention equipment shall include a minimum of:

(1) four remotely controlled, hydraulically operated blowout preventers with a rated working pressure which exceeds the maximum anticipated surface pressure, including at least one equipped with pipe rams, one with blind rams, and one hydril type;

(2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body;

(3) a choke manifold;

(4) a kill line; and

(5) a fill-up line.

D. Testing.—Ram-type blowout preventers and related control equipment shall be tested to the rated working pressure of the stack assembly or to the working pressure of the casing, whichever is the lesser, at the following times:

(1) when installed;

(2) before drilling out after each string of casing is set;

(3) not less than once each week while drilling;

(4) following repairs that require disconnecting a pressure seal in the assembly. The hydril type blowout preventer shall be tested to 70 percent of the above pressure requirements.

While drill pipe is in use ram-type blowout preventers shall be actuated to test proper functioning once each trip, but in no event less than once each day. The hydril type blowout preventer shall be actuated on the drill pipe once each week. Accumulators or accumulators and pumps shall maintain a reserve capacity at all times to provide for repeated operation of hydraulic preventers. A blowout prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties. All blowout preventer tests and crew drills shall be recorded on the driller's log.

E. Other Equipment.—An inside blowout preventer assembly (back pressure valve) and a full opening drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Valves shall be maintained on the rig floor to fit all pipe in the drill string. Also, a socket type, sealing coupling capable of being dropped over exposed drill pipe with a full opening safety valve above it shall be maintained on the rig floor for control situations where flow prevents installation of a safety valve. A top kelly cock shall be installed below the swivel and another at the bottom of the kelly of such design that it can be run through the blowout preventers.

3. Mud Program—General

The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times.

A. Mud Control.—Before starting out of the hole with drill pipe, the mud shall be circulated with the drill pipe just off bottom until the mud is properly conditioned. Proper conditioning requires, at a minimum, circulation to the extent that the annulus volume is displaced. When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops below 100 feet, and a mechanical device for measuring the amount of mud required to fill the hole shall be watched, and any time there is an indication of swabbing or influx of formation fluids, the necessary safety device(s) required in subparagraph 2.E. above shall be installed on the drill pipe, the drill pipe shall be run to bottom and the mud properly conditioned. The mud shall not be circulated and conditioned except on or near bottom, unless well conditions prevent running the pipe to bottom. The mud in the hole shall be circulated or reversed circulated prior to pulling drill stem test tools from the hole.

B. Mud Testing Equipment.—Mud testing equipment shall be maintained on the drilling platform at all times, and mud tests consistent with good operating practice shall be performed daily, or more frequently as conditions warrant.

The following mud system monitoring equipment must be installed (with derrick floor indicators) and used throughout the period of drilling after setting and cementing the conductor casing:

(1) Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual or audio warning device.

(2) Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.

(3) Mud return or full hole indicator to determine when returns have been obtained, or when they occur unintentionally, and additionally to determine that returns essentially equal the pump discharge rate.

D. W. SOLANAS,
Supervisor.

Approved: June 1, 1971.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 3, June 1, 1971]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION—PLUGGING AND ABANDONMENT OF WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.15. The operator shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil and gas. Plugging and abandonment operations must not be commenced prior to obtaining approval for an authorized representative of the Geological Survey. Oral approvals shall be in accordance with 30 CFR 250.13. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Permanent Abandonment

A. Isolation in Uncased Hole.—In uncased portions of wells, cement plugs shall be spaced to extend 100 feet below the bottom to 100 feet above the top of any oil, gas, and fresh water zones so as to isolate fluids in the strata in which they are found and to prevent them from escaping into other strata.

B. Isolation of Open Hole.—Where there is open hole (uncased and open into the casing string above) below the casing, a cement plug shall be placed in the deepest casing string by (1) or (2) below, or in the event lost circulation conditions exist or are anticipated, the plug may be placed in accordance with (3) below:

(1) A cement plug placed by displacement method so as to extend a minimum of 100 feet above and 100 feet below the casing shoe.

(2) A cement retainer with effective back pressure control set not less than 50 fet, nor more than 100 feet, above the casing shoe with a cement plug calculated to extend at least 100 feet below the casing shoe and 50 feet above the retainer.

(3) A permanent type bridge plug set within 150 feet above the casing shoe with 50 feet of cement on top of the bridge plug. This plug shall be tested prior to placing subsequent plugs.

C. Plugging or Isolating Perforated Intervals.—A cement plug shall be placed opposite all open perforations (perforations not squeezed with cement) extending a minimum of 100 feet above and 100 feet below the perforated interval or down to a casing plug whichever is less. In lieu of the cement plug, a bridge plug set at a maximum of 150 feet above the open perforations of each separate interval with 50 feet of cement on top may be used provided the perforations are isolated from the hole below.

D. Plugging of Casing Stubs.—If casing is cut and recovered, thereby leaving a stub inside the next larger string, a cement plug will be set so as to extend 100 feet above and 100 feet below the stub, or a retainer set 50 feet above the stub with 150 feet of cement set below and 50 feet above. A permanent bridge plug set 50 feet above the stub and capped with 50 feet of cement shall be used if the foregoing methods cannot be used. However, if the stub is below the next larger string, plugging must be accomplished in accordance with subparagraphs A and B above.

E. Plugging of Annular Space.—No annular space that extends to the ocean floor shall be left open to drilled hole below. If this condition exists, the annulus shall be plugged with cement.

F. Surface Plug Requirement.—A cement plug of at least 150 feet, with the top of the plug 150 feet or less below the ocean floor, shall be placed in the smallest string of casing which extends to the surface.

G. Testing of Plugs.—The setting and location of the first plug below the 150-foot surface plug shall be verified by placing the weight of the drill string or a minimum pipe weight of 15,000 pounds on the plug, whichever is greater. The top of plugs placed opposite open hole or perforations shall be verified as to location.

H. Mud.—Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval.

I. Clearance of Location.—All casing and anchor piling shall be severed and removed to at least 5 feet below the ocean floor and the ocean floor shall be cleared of any obstructions.

2. *Temporary Abandonments*

Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for requirements of subparagraphs 1.E., F., and I. above. When casing extends above the ocean floor, a mechanical bridge plug (retrievable or permanent) shall be set in the casing between 15 and 200 feet below the ocean floor.

D. W. SOLANAS, *Supervisor.*

Approved: June 1, 1971.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 4, June 1, 1971]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION—SUSPENSIONS AND DETERMINATION OF WELL PRODUCIBILITY

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12(d)(1). An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. The term "paying quantities" as used herein means production in quantities sufficient to yield a return in excess of operating costs. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of production has been approved. Any application for suspension of production for an initial period shall be submitted prior to the expiration of the term of a lease. The Supervisor may approve a suspension of production provided at least one well has been drilled on the lease and he determines it to be capable of being produced in paying quantities. The temporary or permanent abandonment of a well will not preclude approval of a suspension of production as provided in 30 CFR 250.12(d)(1). Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

A well may be determined to be capable of producing in paying quantities when the requirements below have been met.

1. Oil Wells

A deliverability test of at least two hours' duration after the well flow has stabilized which proves that the well is capable of producing oil in paying quantities.

2. Gas Wells

A four-point back pressure test or a measured deliverability test of at least two hours' duration after the well flow has stabilized which proves that the well is capable of producing gas or gas and condensate in paying quantities.

3. Witnessing and Results

All tests must be witnessed by an authorized representative of the Geological Survey. Test data accompanied by operator's affidavit, or third-party test data, may be accepted in lieu of a witnessed test provided prior approval is obtained from the appropriate district office. The results of the witnessed or accepted test must justify a determination that the well is capable of producing in paying quantities.

D. W. SOLANAS, *Supervisor.*
RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 5, June 1, 1971]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION—INSTALLATION OF SUBSURFACE SAFETY DEVICE

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.41(b). Section 250.41(b) provides as follows:

"(b) *Completed wells.*—In the conduct of all its operations, the lessee shall take all steps necessary to prevent blowouts, and the lessee shall immediately take whatever action is required to bring under control any well over which control has been lost. The lessee shall: (1) in wells capable of flowing oil or gas, when required by the supervisor, install and maintain in operating condition storm chokes or similar subsurface safety devices; (2) for producing wells not capable of flowing oil or gas, install and maintain surface safety valves with automatic shut-down controls; and (3) periodically test or inspect such devices or equipment as prescribed by the supervisor."

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. All wells capable of flowing oil or gas shall be equipped with a subsurface safety device installed at a depth of 100 feet or more below the ocean floor. Such device shall be installed in all oil and gas wells, including artificial lift wells, unless proof is provided to the Supervisor that such wells are incapable of any natural flow. For shut-in wells capable of flowing oil or gas, a tubing plug may be installed, in lieu of a subsurface safety device, and such plug shall be installed when required by the Supervisor.

2. Subsurface safety devices shall be adjusted, installed, and maintained to insure reliable operation. Each subsurface safety device and tubing plug installed in a well shall be tested at intervals not exceeding 6 months. Where a safety

valve is set in a landing nipple and is of the type that is controlled from the surface by a hydraulic line or other means, the valve may be tested from the surface to insure proper functioning. If the valve does not operate properly it shall be removed, repaired, reinstalled or replaced and again checked for proper operation.

When a subsurface safety device is removed from a well for repair or replacement, a standby subsurface safety device or tubing plug shall be available at the well location. In the event of an emergency such device shall be immediately installed within the limits of practicability, consideration being given to time, equipment, and personnel safety.

Subsurface safety devices that are an integral part of the tubing string shall be tested at intervals not exceeding six months and, if the test is unsatisfactory, shall be replaced or a removable subsurface device shall be installed.

All wells in which a subsurface device or tubing plug is installed shall have the tubing-casing annulus sealed below the valve or plug setting depth.

3. In all tubing installations made after the effective date of this Order, the tubing string shall be equipped with a surface-controlled subsurface safety device. In high-flow-rate wells or wells producing sand, areas of turbulence above and below such devices shall be protected by flow couplings or other protective equipment. Wells which are presently equipped with direct-controlled subsurface safety devices shall have surface-controlled subsurface safety devices installed the first time the tubing is pulled after the effective date of this Order, or within one year after the effective date of this Order, whichever occurs sooner. The control system for the surface-controlled subsurface safety devices shall be an integral part of the platform shut-in system.

4. The well completion report on Form 9-330 and any subsequent report of workover on Form 9-331 shall state the type and the depth of the subsurface safety device or tubing plug installed in the well or state that the requirement has been waived.

5. The operator shall maintain records, available at a structure in the field to any authorized representative of the Geological Survey, showing the present status and past history of each subsurface safety device or tubing plug, including dates and details of inspection, testing, repairing, adjustment and reinstallation or replacement. The operator shall submit a copy of such records semiannually to the District Engineer.

D. W. SOLANAS, *Supervisor.*

Approved: June 1, 1971.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 6, June 1, 1971]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION—PROCEDURE FOR COMPLETION OF OIL AND GAS WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.92. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. *Wellhead Equipment and Testing Procedures*

A. Wellhead Equipment.—All completed wells shall be equipped with casingheads, wellhead fittings, valves, and connections with a rated working pressure equal to or greater than the surface shut-in pressure of the well. Connections and valves shall be designed and installed to permit fluid to be pumped between any two strings of casing. Two master valves shall be installed on the tubing in wells with a surface pressure in excess of five thousand pounds per square inch. All wellhead connections shall be assembled and tested, prior to installation, by a fluid pressure which shall be equal to 1.5 times the rated working pressure of the fitting to be installed.

B. Testing Procedure.—Any wells showing sustained pressure on the casinghead, or leaking gas or oil between the production casing and the next larger casing string, shall be tested in the following manner: The well shall be killed with water or mud and pump pressure applied to the production casing string. Should the pressure at the casing head reflect the applied pressure, corrective measures must be taken and the casing shall again be tested in the same manner. This testing procedure shall be used when the origin of the pressure cannot be determined otherwise.

2. *Subsurface Safety Device*

All completed wells shall meet the requirements prescribed in OCS Order No. 5.

3. *Procedures for Multiple or Tubingless Completions*

A. Multiple Completions

(1) Information shall be submitted on, or attached to, Form 9-331 showing top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.

(2) When zones approved for multiple completion become intercommunicated the lessee shall immediately repair and separate the zones after approval is obtained.

B. Tubingless Coplctions

(1) All tubing strings in a multiple completed well shall be run to the same depth below the deepest producible zone.

(2) The tubing string(s) shall be new pipe or equivalent and shall be cemented with a sufficient volume to extend a minimum of 500 feet above the uppermost producible zone.

(3) A temperature or cement bond log shall be run in all tubingless completion wells where lost circulation or other unusual circumstances occur during the cementing operations.

(4) Information shall be submitted on, or attached to, Form 9-331 showing the top and bottom of all zones proposed for completion or alternate completion, including a partial electric log and a diagrammatic sketch showing such zones and equipment to be used.

D. W. SOLANAS, *Supervisor.*

Approved: June 1, 1971.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 7, June 1, 1971]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION—POLLUTION AND WASTE DISPOSAL

This order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.43. Section 250.43 provides as follows:

"(*a*) The lessee shall not pollute land or water or damage the aquatic life of the sea or allow extraneous matter to enter and damage any mineral- or water-bearing formation. The lessee shall dispose of all liquid and non-liquid waste materials as prescribed by the supervisor. All spills or leakage of oil or waste materials shall be recorded by the lessee and, upon request of the supervisor, shall be reported to him. All spills or leakage of a substantial size or quantity, as defined by the supervisor, and those of any size or quantity which cannot be immediately controlled also shall be reported by the lessee without delay to the supervisor and to the Coast Guard and the Regional Director of the Federal Water Pollution Control Administration. All spills or leakage of oil or waste materials of a size or quantity specified by the designee under the pollution contingency plan shall also be reported by the lessee without delay to such designee.

"(*b*) If the waters of the sea are polluted by the drilling or production operations conducted by or on behalf of the lessee, and such pollution damages or threatens to damage aquatic life, wildlife, or public or private property, the control and total removal of the pollutant, wheresoever found, proximately resulting therefrom shall be at the expense of the lessee. Upon failure of the lessee to control and remove the pollutant the supervisor, in cooperation with other appropriate agencies of the Federal, State and local governments, or in cooperation with the lessee, or both, shall have the right to accomplish the control and removal of the pollutant in accordance with any established contingency plan for combating oil spills or by other means at the cost of the lessee. Such action shall not relieve the lessee of any responsibility as provided herein.

"(c) The lessee's liability to third parties, other than for cleaning up the pollutant in accordance with paragraph (b) of this section, shall be governed by applicable law."

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Pollution Prevention

In the conduct of all oil and gas operations, the operator shall not pollute land or water. The operator shall comply with the following pollution prevention requirements.

A. Liquid Disposal

(1) The disposal of produced waste water and sewage shall be in accordance with the provisions of OCS Order No. 8.

(2) Oil shall not be disposed of into ocean waters.

(3) Liquid waste materials containing substances which may be harmful to aquatic life or wildlife, or injurious in any manner to life or property, shall be treated to avoid disposal of harmful substances into the ocean waters.

(4) Drilling mud containing oil or toxic substances shall not be disposed of into the ocean waters.

B. Solid Waste Disposal

(1) Drill cuttings, sand, and other solids containing oil shall not be disposed of into the ocean waters.

(2) Mud containers and other solid waste materials shall be transported to shore for disposal.

C. Production Facilities

(1) All production facilities, such as separators, tanks, treaters, and other other equipment, shall be operated and maintained at all times in a manner necessary to prevent pollution.

(2) The operator's personnel shall be thoroughly instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Non-operator personnel shall be informed in writing, prior to executing contracts, of the operator's obligations to prevent pollution.

2. Inspections and Reports

The operator shall comply with the following pollution inspection and reporting requirements and operators shall comply with such instructions or orders as are issued by the Supervisor for the control or removal of pollutants:

A. Pollution Inspections

(1) Manned drilling and production facilities shall be inspected daily to determine if pollution is occuring. Such maintenance or repairs as are necessary to prevent pollution of ocean waters shall be immediately undertaken and performed.

(2) Unattended facilities, including those equipped with remote control and monitoring systems, shall be inspected at intervals as prescribed by the District Engineer and necessary maintenance or repairs immediately made thereto.

B. Pollution Reports

(1) All spills or leakage of oil and liquid pollutants shall be reported orally without delay to the District Engineer and the Coast Guard and shall be followed by a written report to the District Engineer showing the cause, size of spill, and action taken.

(2) All spills or leakage of oil and liquid pollutants of a substantial size or quantity and those of any size or quantity which cannot be immediately controlled, shall be reported orally without delay to the Supervisor, the District Engineer, the Coast Guard, and the Regional Director, Environmental Protection Agency.

(3) Operators shall notify each other upon observation of equipment malfunction or pollution resulting from another's operation.

3. Control and Removal

A. Corrective Action

Immediate corrective action shall be taken in all cases where pollution has occurred. Each operator shall have an emergency plan for initiating corrective action to control and remove pollution and such plan shall be filed with the Supervisor. Corrective action taken under the plan shall be subject to modification when directed by the Supervisor.

B. Equipment

Standby pollution control equipment shall be maintained at each operation or shall be immediately available to each operator at an onshore location. This equipment shall include, but need not be limited to, containment booms, skimming apparatus, and chemical dispersants and shall be available prior to the commencement of operations. This equipment shall be the most effective available resulting from the current state of pollution control and removal research and development efforts. The equipment shall be regularly inspected and maintained in good condition for use. The equipment and the location of land bases shall be approved by the Supervisor. Chemical dispersants shall not be used without prior approval of the Supervisor. The operator shall notify the Supervisor of the location at which such equipment is located for operations conducted on each lease. All changes in location and equipment maintained at each location shall be approved by the Supervisor.

Approved: June 1, 1971.

D. W. SOLANAS,
Supervisor.
RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 8, June 1, 1971]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION—APPROVAL PROCEDURE FOR INSTALLATION AND OPERATION OF PLATFORMS, FIXED AND MOBILE STRUCTURES, AND ARTIFICIAL ISLANDS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11, and in accordance with 30 CFR 250.19(a). Section 250.19(a) provides as follows:

"(*a*) The supervisor is authorized to approve the design, other features, and plan of installation of all platforms, fixed structures, and artificial islands as a condition of the granting of a right of use or easement under paragraph (a) or (b) of section 250.18 or authorized under any lease issued or maintained under the Act"

Platforms, fixed structures and artificial islands are hereinafter referred to as structures. The operator shall be responsible for compliance with the requirements of this Order in the installation and operation of all platforms, fixed and mobile structures, and artificial islands, including all facilities installed on a structure whether or not operated or owned by the operator. The requirements of subparagraphs 2.A.(3), (4), (8), and (9) of this Order shall apply to all mobile drilling structures used to conduct drilling or workover operations on Federal leases in the Pacific Region.

Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. The following requirements are applicable to all structures approved and installed subsequent to the effective date of this Order, and to all structures when structural and equipment modifications are to be made:

A. General Design

The design of structures shall include consideration of such factors as water depth, surface and subsurface soil conditions, wave and current forces, wind forces, total equipment weight, seismic forces, and other pertinent geological, geographical, environmental, and operational conditions. At the discretion of the Supervisor, the operator may first obtain preliminary approval of the design of the structure by submitting general specifications which will demonstrate that a satisfactory installation can be designed. The operator may then proceed with detailed design work for final approval which shall comply with the requirements listed below.

B. Application

The operator shall submit in duplicate, for approval, the following to the appropriate District Office.

(*1*) *Design Features.*—Information relative to design features on a plat or plats showing the structure dimensions, plan and two elevations, number and location of well slots, and water depth. In addition, the plat shall include:

(*a*) Nominal size and thickness range of piling.

(*b*) Nominal size and thickness range of jacket column leg.

(*c*) Nominal size and thickness range of deck column leg.

(*d*) Design piling penetration.

(*e*) Maximum bearing and lateral load per pile in tons.

(*f*) Identification data which shall be the OCS lease number, the structure designation, and the name of the lease operator.

(*g*) The following certification signed and dated with the title of the company representative:

"———————— certifies that this structure has been certified by a registered professional engineer and that the structure is designed to withstand the specific stresses and conditions outlined in subparagraph 1.A. and as detailed in subparagraph 1.B.(2)(g) of OCS Order No. 8 and will be constructed, operated, and maintained as described in the application, and any approved modification thereto. Certified plans are on file at ————————."

(2) *Other Features.*—Information relative to other features including the following:

(*a*) Primary use intended, including drilling and/or production of oil and gas.

(*b*) Personnel and personnel transfer facilities, including living quarters, boat landings, and heliport.

(*c*) Type of deck, such as steel sheeting or open grating, and whether coated with protective material.

(*d*) Method of protection from corrosion.

(*e*) Production facilities including separators, treaters, storage tanks, compressors, line pumps, and metering devices, except that when initially designed and utilized for drilling, this information may be submitted prior to installation.

(*f*) Safety and pollution control equipment and features.

(*g*) The design parameters used and the maximum stresses for which designed in terms of the specific forces and conditions outlined in subparagraph 1.A. above.

(*h*) Other information when required.

C. Certified Plan

Detailed structural plans certified by a registered professional engineer shall be on file and maintained by the operator or his designee.

2. *Safety and Pollution Control Equipment and Procedures*

A. The following requirements shall apply to all structures. Subparagraphs 2.A. (3), (4), (8), and (9) shall also apply to mobile drilling structures. Operators of existing structures, including mobile drilling structures, shall have 90 days from the date of this Order in which to comply with the requirements of subparagraphs 2.A. (1) through (8) and one year in which to comply with subparagraph 2.A.(9).

(1) The following devices shall be installed and maintained in an operating condition on all pressurized vessels and water separation facilities when such vessels and separation facilities are in service. The operator shall maintain records on the structure or facilty showing the present status and past history of each such device including dates and details of inspection, testing, repairing, adjustment, and reinstallation or replacement.

(*a*) All separators shall be equipped with high-low pressure shut-in sensors, low level shut-in controls, and a relief valve. High liquid level control devices shall be installed when the vessel can discharge to a gas vent line.

(*b*) All pressure surge tanks shall be equipped with a high and low pressure shut-in sensor, a high level shut-in control, gas vent line, and relief valve.

(*c*) Atmospheric surge tanks shall be equipped with a high level shut-in sensor.

(*d*) All other hydrocarbon handling pressure vessels shall be equipped with high-low pressure shut-in sensors, high-low level shut-in controls, and relief valves, unless they are determined by the Supervisor to be otherwise protected.

(*e*) Pilot-operated pressure relief valves shall be equipped to permit testing with an external pressure source. Spring-loaded pressure relief valves shall either be bench-tested or equipped to permit testing with an external pressure source. A relief valve shall be set no higher than the designed working pressure of the vessel. The high pressure shut-in sensor shall be set no higher than 5% below the rated or designed working pressure and the low pressure shut-in sensor shall be set no lower than 10% below the lowest pressure in the operating pressure range on all vessels with a rated or designed working pressure of more than 400 psi. On lower pressure vessels the above percentages shall be used as guidelines for sensor settings considering pressure and operating conditions invloved; except that sensor settings shall not be within 5 psi of the rated or designed working pressure or the lowest pressure in the operating pressure range.

(*f*) All pressure-operated sensors shall be equipped to permit testing with an external pressure source.

(*g*) All gas vent lines shall be equipped with a scrubber or similar separation equipment.

(2) The following devices shall be installed and maintained in an operating condition at all times when the affected well (or wells) is producing. The operator shall maintain records on the structure or facility showing the present status and past history of each such device, including dates and details of inspection, testing, repairing, adjustment, and reinstallation or replacement.

(*a*) All well head assemblies shall be equipped with an automatic fail-close valve. Automatic safety valves temporarily out of service shall be flagged.

(*b*) All flowlines from wellheads shall be equipped with high-low pressure sensors located close to the wellhead. The pressure sensors shall be set to activate the wellhead valve in the event of abnormal pressures in the flowline.

(*c*) All headers shall be equipped with check valves on the individual flowlines. The flowline and valves from each well located upstream of, and including, the header valves shall withstand the shut-in pressure of that well, unless protected by a relief valve with connections to bypass the header. If there is an inlet valve to a separator, the valve, flowline, and all equipment upstream of the valve shall also withstand shut-in wellhead pressure, unless protected by a relief valve with connections to bypass the header.

(*d*) All pneumatic, hydraulic, and other shut-in control lines shall be equipped with fusible material at strategic points.

(*e*) Remote shut-in controls shall be located on the helicopter deck and all exit stairway landings leading to the helicopter deck and to all boat landings. These controls shall be quick-operating devices.

(*f*) All pressure sensors shall be operated and tested for proper pressure settings monthly for at least four months. At such time as the monthly results are consistent, a quarterly test shall be required for at least one year. If these results are consistent, a longer period of time between testing may then be approved by the Supervisor. In the event any testing sequence reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained on a structure in the field.

(*g*) All automatic wellhead safety valves shall be tested for operation weekly. All automatic wellhead safety valves shall be tested for holding pressure monthly. If these results are consistent, a longer period of time between pressure tests, not to exceed quarterly, may then be approved by the Supervisor. In the event that any pressure testing sequence, exceeding monthly, reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained on a structure in the field.

(*h*) Check valves shall be tested for holding pressure monthly for at least four months. At such time as the monthly results are satisfactory, a quarterly test shall be required for at least one year. If these results are consistent, a longer period of time between testing may then be approved by the

Supervisor. In the event any testing sequence reveals inconsistent results, the monthly testing sequence shall be reinstituted. Results of all tests shall be recorded and maintained on a structure in the field.

(*i*) A complete testing and inspection of the safety system shall be witnessed by Geological Survey representatives at the time production is commenced. Thereafter, the operator shall arrange for a test every six months. The test shall be conducted when it can be witnessed by Geological Survey representatives.

(*j*) A standard procedure for testing of safety equipment shall be prepared and posted in a prominent place on the platform.

(3) Curbs, gutters, and drains shall be constructed and maintained in good condition in all deck areas in a manner necessary to collect all contaminants, unless drip pans or equivalent are placed under equipment and piped to a sump which will automatically maintain the oil at a level sufficient to prevent discharge of oil into the ocean waters. Alternate methods to obtain the same results may be approved by the Supervisor. These systems shall not permit spilled oil to flow into the wellhead area.

(4) An auxiliary electrical power supply shall be installed to provide emergency power capable of operating all electrical equipment required to maintain safety of operation in the event the primary electrical power supply fails.

(5) The following requirements shall apply to the handling and disposal of all produced waste water discharged into the ocean waters overlying the submerged lands of the OCS. The disposal of waste water other than into these waters shall be approved by the Supervisor.

(*a*) Water discharged shall not create conditions which will adversely affect the public health or the use of the waters for the propagation of aquatic life, recreation, navigation, or other legitimate uses.

(*b*) Waste water disposal systems shall be designed and maintained to reduce the oil content of the disposed water to not more than fifty ppm. An effluent sampling station shall be located at a point prior to discharge into the receiving waters where a representative sample of the treated effluent can be obtained. On one day each month the effluent shall be sampled hourly for 8 hours and the following determinations shall be made on the composite sample: suspended solids, settleable solids, pH, total oil and grease content, and volume of sample obtained. Also the temperature of each hourly sample shall be recorded. All samples shall be taken and all analyses for oil and grease content shall be performed in accordance with the latest edition of "Standard Methods for the Examination of Water and Wastewater", published by the American Public Health Association, Inc. The Supervisor may approve different methods for determination of oil and grease content if the method to be used is indicated to be reliable. A written report of the results shal be furnished to the Regional Office monthly. The report shall contain dates, time and location of sample, volumes of waste discharge on the date of sampling in barrels per day, and the results of the specific analysis and physical observations. A visual inspection of the appearance of the receiving waters in the discharge area shall be made daily and the results recorded and included in the monthly report.

(6) A firefighting system shall be installed and maintained in an operating condition in accordance with the following:

(*a*) A fixed automatic water spray system shall be installed in all wellhead areas. These systems shall be installed in accordance with the current edition of National Fire Protection Association's Pamphlet No. 15.

(*b*) A firewater system of rigid pipe with fire hose stations shall be installed and may include a fixed water spray system. Such a system shall be installed in a manner necessary to provide needed protection in areas where production handling equipment is located. A firefighting system using chemicals may be considered for installation in certain areas in lieu of a firewater system in that area, if determined by the Supervisor to provide equivalent fire protection control.

(*c*) Pumps for the firewater systems shall be test-operated weekly. A record of the tests shall be maintained on a structure in the field and submitted semiannually to the District Office. An alternate fuel or power source shall be installed to provide continued pump operation during platform shutdown unless an alterante firefighting system is provided.

(*d*) Portable fire extinguishers shall be located in the living quarters and in other strategic areas.

(*e*) A diagram of the firefighting system showing the location of all equipment shall be posted in a prominent place on the structure and a copy submitted to the District Office.

(7) An automatic gas detector and alarm system shall be installed and maintained in an operating condition in accordance wih the following:

(*a*) Gas detection systems shall be installed in all enclosed areas containing gas handling facilities or equipment and in other enclosed areas which are classified as hazardous areas as defined in API RP 500 A and B and the current edition of the National Electric Code.

(*b*) All gas detection systems shall be capable of continuously monitoring for the presence of combustible gas in the areas in which the detection devices are located.

(*c*) The central control shall be capable of giving an alarm at a point not higher than 60 percent of the lower explosive limit.

(*d*) The central control shall automatically activate shut-in sequences and emergency equipment at a point not higher than 90% of the lower explosive limit.

(*e*) An application for the installation and maintenance of any gas detection system shall be filed with the appropriate District Office for approval. The application shall include the following:

(i) Type, location, and number of detection or sampling heads.

(ii) Cycling, non-cycling, and frequency information.

(iii) Type and kind of alarm including emergency equipment to be activated.

(iv) Method used for detection of combustible gas.

(v) Method and frequency of calibration.

(vi) A diagram of the gas detection system.

(vii) Other pertinent information.

(*f*) A diagram of the gas detection system showing the location of all gas detection points shall be posted in a prominent place on the structure.

(8) The following requirements shall be applicable to all electrical equipment and systems installed:

(*a*) All gas and gasoline engines shall be equipped with low-tension ignition systems containing rigid connections and shielded wiring which shall prevent the release of sufficient electrical energy under normal or abnormal conditions to cause ignition of a combustible mixture.

(*b*) All electrical generators, motors, and lighting systems shall be installed, protected, and maintained in accordance with the current edition of the electrical code of the adjacent State, National Electric Code, and API RP 500 A and B, as appropriate. On mobile drilling structures, certificated by the Coast Guard, this equipment shall be installed, protected, and maintained in accordance with the applicable provisions of 46 CFR 110 through 113, inclusive.

(*c*) Marine-armored cable or metal-clad cable may be substituted for wire in conduit in any area.

(9) Sewage disposal systems shall be installed and maintained in satisfactory operating condition in all cases where sewage is discharged into the ocean waters. Sewage is defined as human body wastes and the wastes from toilets and other receptacles intended to receive or retain body wastes. Following sewage treatment, the effluent shall contain 50 ppm or less of biochemical oxygen demand (BOD), 150 ppm or less of suspended solids, and shall have a minimum chlorine residual of 1.0 mg/liter after a minimum retention time of fifteen minutes. Sewage treatment records shall be maintained and made available for inspection upon request. The records shall reflect the results of monthly tests. These tests shall include determination of BOD, suspended solids, and chlorine residual.

B. Welding Practices and Procedures

The following requirements shall apply to all structures, including mobile drilling structures, as applicable. The period of time during which these requirements are considered applicable to mobile drilling structures is the interval from the drilling out of the shoe of the conductor casing until the BOP stack and the marine riser are pulled in the process of final abandonment or suspension. For the purpose of this Order the term "welding and burning" is defined to include arc or acetylene welding and arc or acetylene cutting.

(1) All welding and burning shall be minimized.

(2) Such welding or burning as is necessary, on a structure, shall adhere to the following practices:

(*a*) Welding or burning on the structure should be done in an approved, properly functioning welding room; however, all welding and burning that is required but that cannot be prudently done in the welding room, shall be performed in compliance with the procedures outlined below.

(*b*) Prior to the commencement of any burning or welding operations, on a structure, the senior person in charge at the installation shall personally inspect the area in which the work is to be done. After this person has determined that it is safe to proceed, he shall issue a written authorization for the work. If both drilling and production operations are being conducted on the structure, the senior drilling man and the senior production man shall make this inspection and both shall sign it.

(*c*) A copy of each welding or burning authorization shall be maintained on the structure for a period of one year. These authorizations shall be made available, for inspection, to any authorized representative of the Geological Survey.

(*d*) During all welding or burning operations, one or more persons as necessary shall be designated as a "fire watch". Persons assigned to "fire watch" shall have no other duties while so assigned.

(*e*) The "fire watch" shall wear an item of distinctive clothing (vest or coat) for identification purposes and shall have in his immediate possession a portable gas detector and a portable fire extinguisher.

(*f*) If welding or burning must be done on containers, tanks, or other vessels which have contained a flammable substance, these objects shall be thoroughly cleaned and rendered free of such flammable substance before the work begins.

(*g*) If welding or burning must be done on in-service or connected-up piping, that section of pipe shall be isolated by tightly closed valves, blind flanges, or other suitable means, bled to atmospheric pressure, and thoroughly purged and cleaned to render it free of any flammable substance.

(*h*) If welding or burning must be done in confined spaces, the space shall be adequately vented and a continuous source of fresh air shall be supplied while work is in progress. If the fresh air is supplied by blowers, they shall be so positioned that the intakes will not pick up exhausted gases, fumes, or vapors.

(*i*) If any welding or burning is done on bulkheads, decks, or overheads, the adjacent, overlying, or underlying spaces shall be examined to determine that it is safe for the work to proceed. If deemed advisable, a second "fire watch" shall be employed in the contiguous area.

(*j*) If any welding or burning must be done on structural members, it shall be determined by a competent authority that such welding or burning does not endanger the integrity of the structure.

D. W. SOLANAS, *Supervisor.*

Approved June 1, 1971.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 9, June 1, 1971]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, PACIFIC REGION

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION—APPROVAL PROCEDURE FOR PIPELINE

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.19(b). Section 250.19(b) provides as follows:

"(*b*) The supervisor is authorized to approve the design, other features, and plan of installation of all pipelines for which a right of use or easement has been granted under paragraph (c) of section 250.18 or authorized under any lease issued or maintained under the act, including those portions of such lines which extend onto or traverse areas other than the Outer Continental Shelf."

The operator shall comply with the following requirements. Platforms, fixed structures, and artificial islands are hereinafter referred to as structures. This

Order does not apply to common carrier pipelines except as to that portion connected to or crossing a structure. Any departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. General Design

All pipelines shall be designed and maintained in accordance with the following:

A. The operator shall be responsible for the installation of the following control devices on all oil and gas pipelines connected to a structure, including pipelines which are not operated or owned by the operator. Operators of structures installed prior to the effective date of this Order shall comply with the requirements of subparagraphs (1) through (6) within 6 months of the effective date of this Order. The operator shall maintain records on the structure or facility showing the present status and past history of each device, including dates and details of inspection, testing, repairing, adjustment reinstallation or replacement.

(1) All oil and gas pipelines leaving a structure receiving production from the structure shall be equipped with a high-low pressure sensor to shut in the wells on the structure.

(2) All oil and gas pipelines delivering production to either offshore or onshore production facilities, or both, shall be equipped with an automatic shut-in valve, at or near the receiving facility, connected to an automatic and a remote shut-in system.

(3) All oil and gas pipelines coming onto a structure or delivering production to an onshore facility shall be equipped with a check valve or a quick-operating manual valve, as approved by the Supervisor, at or near the structure or facility to control backflow.

(4) All oil and gas pipelines crossing a structure which do not deliver production to the structure, but which may or may not receive production from the structure, shall be equipped with sensors to activate an automatic shut-in valve to be located in the upstream portion of the pipeline at or near the structure to avoid uncontrolled flow at the structure. This automatic shut-in valve shall be connected to either the structure automatic and remote shut-in system or to an independent remote shut-in system.

(5) All oil pumps and gas compressors shall be equipped with high-low pressure shut-in devices.

(6) All oil pipelines shall have a metering system to provide a continuous volumetric comparison of input to the line at the structure, or structures, with deliveries onshore. The system shall include an alarm system and shall be of adequate sensitivity to detect significant variations between input and discharge volumes. In lieu of the foregoing, any system capable of detecting small leaks in the pipeline may be substituted with the approval of the Supervisor.

B. All oil and gas and other pipelines shall be protected from loss of metal that would endanger the strength and safety of the lines by methods such as protective coatings or cathodic protection.

C. All oil and gas and other pipelines shall be installed and maintained to be compatible with trawling operations and other uses.

D. All oil and gas and other pipelines shall be hydrostatically tested to 1.25 times the designed working pressure for a minimum of 2 hours prior to placing the line in service.

E. All oil and gas pipelines shall be maintained in good operating condition at all times and the ocean surface above the pipeline shall be inspected at a minimum of once each week for indication of leakabe using aircraft, floating equipment or other means. Records of these inspections including the date, methods, and results of each inspection shall be maintained by the operator and submitted to the District Engineer annually by April 1. The operator shall immediately notify the District Engineer of any pipeline leak and within one week shall submit a report to him with respect to the cause, effect, and remedial action taken.

F. All oil and gas and other pipelines shall be designed and maintained for protection against water currents, storm scouring, soft bottoms, and other environmental factors.

G. An external inspection of all pipelines by side scan sonar or other means acceptable to the Supervisor shall be made at least once each year to identify all exposed portions of pipelines. All exposed portions of pipelines shall then be inspected in detail by photographic or other means acceptable to the Supervisor to determine if any hazards exist to the line or other users of the area. If a hazard is found to exist, appropriate corrective action shall be taken. Records of these inspections including the date, methods, and results of each inspection, shall be maintained by the operator and submitted to the District Engineer when the records become available.

2. Application

The operator shall submit in duplicate the following to the District Engineer for forwarding and approval by the Supervisor:

A. Drawing on a plat or plats showing the major features and other pertinent data including: (1) water depth, (2) route, (3) location, (4) length, (5) connecting facilities, (6) size, and (7) burial depth, if buried.

B. A schematic drawing showing the location of the following pipeline safety equipment and the manner in which the equipment functions: (1) high-low pressure sensors, (2) automatic shut-in valves, (3) check valves, and (4) the volumetric metering system.

C. General information concerning the pipeline including the following:

(1) Product or products to be transported by the pipeline.
(2) Size, weight and grade of the pipe.
(3) Length of line.
(4) Maximum water depth.
(5) Type or types of corrosion protection.
(6) Description of protective coating.
(7) Bulk specific gravity of line (with the line empty).
(8) Anticipated gravity or density of the product or products.
(9) Design working pressure and capacity.
(10) Maximum working pressure and capacity.
(11) Hydrostatic pressure and hold time to which the line will be tested after installation.
(12) Size and location of pumps and prime movers.
(13) Any other pertinent information as the Supervisor may prescribe.

3. Completion Report

The operator shall notify the District Engineer when installation of the pipeline is completed and submit a drawing, in duplicate, showing the location of the line as installed, accompanied by all hydrostatic test data, including procedure, test pressure, hold time, and results.

D. W. SOLANAS, *Supervisor.*

Approved: June 1, 1971.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 10, June 1, 1971]

U.S. DEPARTMENT OF THE INTERIOR, BRANCH OF OIL AND GAS OPERATIONS, PACIFIC REGION

NOTICE TO PERMITTEES OF TWIN CORE HOLE PERMITS IN THE OUTER CONTINENTAL SHELF, PACIFIC REGION—DRILLING OF TWIN CORE HOLES

The Secretary of the Interior on November 3, 1965, approved the drilling of core holes on unleased lands of the Uter Continental Shelf off the coast of Southern California (30 Federal Register No. 218, Nov. 10, 1965). Authority was delegated to the Regional Oil and Gas Supervisor of the U.S. Geological Survey to approve the drilling of such wells provided (1) the core hole to be drilled is located within 100 feet of a well heretofore drilled under a State permit, or such greater distance from such a well as the Supervisor may prescribe where the prior drilled well is less than three geographical miles from the coastline, (2) the maximum depth to which a core hole may be drilled shall be the depth of the prior drilled well, (3) the approvals to drill core holes granted by the Supervisor shall be conditioned upon compliance with the regulations in 30 CFR Part 250, and such other reasonable requirements as he may prescribe, and (4) no approval to drill shall be granted until the applicant has posted an acceptable corporate surety bond in the amount prescribed in 43 CFR 3304.1, conditioned on compliance with all the requirements set forth in the permits to drill granted by the Supervisor.

In addition to the above, the permittee shall comply with the following requirements:

1. OCS Orders No. 1, 2, 3, 7, and 8 are hereby made applicable to core drilling operations.

2. An application for a general permit to conduct core drilling shall have been filed for approval prior to the filing of any applications to drill specific core holes.

3. A $300,000 corporate surety bond (Form 3380-3) covering Pacific Coast OCS operations shall have been filed.

4. Each application to drill a core hole (Form 9-331C in triplicate) shall be held in an open file in the Supervisor's office for 15 days after filing before approval may be granted. Only the application shall be considered public information.

5. The permittee shall: (a) obtain or have a geological survey blanket permit from the State to drill core holes within State waters, (b) obtain appropriate permission from the Army Corps of Engineers for the location of drilling ships (as provided in the Secretary of the Interior's Notice in 18 FR No. 186, Sept. 23, 1953).

6. All core hole locations shall be described by the Lambert Coordinate System for reference purposes applicable to the location in which it falls.

7. In each application to drill a twin core hole, the original State-permitted core hole shall be identified.

8. The permittee shall file a statement as to the exact location of the surface of the approved core hole and certify that it is within 100 feet of the original core hole at such time as drilling commences.

9. No directionally drilled core holes will be permitted.

10. Mud log and gas detector equipment shall be in operation while drilling below the shoe of the surface casing on twinned holes and below the shoe of the conductor casing on core holes offsetting the three-mile line nor being drilled as a twin.

11. No down-hole formation fluid sampling equipment shall be operated at any time.

12. Conventional coring will be permitted either to total approved depth or such lesser depth as prescribed by the Supervisor provided the permittee of the original core hole being twinned has not filed an affidavit with the Supervisor stating that no conventional coring had been conducted in the original core hole. Sidewall sample coring may be conducted in that part of the hole in which an electric log has been run. Upon completion of operations the permittee shall file with the Supervisor a duly attested duplicate copy of the contractor's original log (tour sheet).

13. The permittee shall advise the District Engineer, Geological Survey, at least 48 hours prior to the drilling and reaching of the approved total depth. The "measuring out" of drill pipe at total depth will be witnessed by the District Engineer or his representative.

14. The permittee shall not commence any abandonment operations prior to obtaining written approval from the District Engineer, Geological Survey. Abandonment of the core hole and clearing of the location of all obstructions on the ocean floor shall be witnessed by a representative of the Geological Survey.

15. Such other requirements as shall be prescribed in the general permit or the specific approved core hole application, or at any time such additional requirements are deemed necessary by the Supervisor or his representative.

D. W. SOLANAS, *Supervisor.*

Approved: June 1, 1971.

RUSSELL G. WEYLAND,
Chief, Conservation Division.

[OCS Order No. 11, effective May 1, 1975]

U.S. DEPARTMENT OF THE INTERIOR, PACIFIC AREA

OIL AND GAS PRODUCTION RATES, PREVENTION OF WASTE, AND PROTECTION OF CORRECTIVE RIGHTS

This Order is established pursuant to the authority prescribed in 30 CFR 250.1 and 30 CFR 250.11, and in accordance with all other applicable provisions of 30 CFR Part 250, and the Notice appearing in the Federal Register, dated December 5, 1970 (35 FR 18559), to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf, and the protection of correlative rights therein. This Order shall be applicable to all oil and gas wells on Federal leases in the Outer Continental Shelf of the Pacific Area. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). References in this Order to approvals, determinations, and requirements for submitting of information or applications for approval are to those granted, made, or required by the Oil and Gas Supervisor or his delegated representative.

1. Definition of Terms

As used in this Order, the following terms shall have the meanings indicated:

A. Waste of Oil and Gas

The definition of waste appearing in 30 CFR 250.2(h) shall apply, and includes the failure to timely initiate enhanced recovery operations where such methods would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles. Enhanced recovery operations refers to pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations which alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.

B. Correlative Rights

The opportunity afforded each lessee or operator to produce without waste his just and equitable share of oil and gas from a common source of supply.

C. Maximum Efficient Rate (MER)

The maximum sustainable daily oil or gas withdrawal rate from a reservoir which will permit economic development and depletion of that reservoir without detriment to ultimate recovery.

D. Maximum Production Rate (MPR)

The approved maximum daily rate at which oil may be produced from a specified oil well completion or the maximum approved daily rate at which gas may be produced from a specified gas well completion.

E. Interested Party

The Operators and lessees, as defined in 30 CFR 250.2(f) and (g), of the lease or leases involved in any proceeding initiated under this Order.

F. Reservoir

An oil or gas accumulation which is separated from and not in oil or gas communication with any other such accumulation.

G. Competitive Reservoir

A reservoir as defined herein containing one or more producible or producing well completions on each of two or more leases, or portions thereof, in which the lease or operating interests are not the same.

H. Property Line

A boundary dividing leases, or portions thereof, in which the lease or operating interest is not the same. The boundaries of federally approved unit areas shall be considered property lines. The boundaries dividing leased and unleased acreage shall be considered property lines for the purpose of this Order.

I. Oil Reservoir

A reservoir that contains hydrocarbons predominantly in a liquid (single-phase) state.

J. Oil Well Completion

A well completed in an oil reservoir or in the oil accumulation of an oil reservoir with an associated gas cap.

K. Gas Reservoir

A reservoir that contains hydrocarbons predominantly in a gaseous (single-phase) state.

L. Gas Well Completion

A well completed in a gas reservoir or in the gas cap of an oil reservoir with an associated gas cap.

M. Oil Reservoir with an Associated Gas Cap

A reservoir that contains hydrocarbons in both a liquid and a gaseous state (two-phase).

N. Producible Well Completion

A well which is physically capable of production and which is shut-in at the wellhead or at the surface, but not necessarily connected to production facilities, and from which the operator plans future production.

2. Classification of Reservoirs

A. Initial Classification

Each producing reservoir shall be classified by the operator, subject to approval by the Supervisor, as an oil reservoir, an oil reservoir with an associated gas cap, or a gas reservoir.

(1) The initial classification of each reservoir from which production is commenced subsequent to the date of this Order shall be submitted for approval with the initial submittal of MER data for the reservoir.

(2) Each reservoir from which production commenced on or prior to the date of this Order shall be classified by the operator, based on existing reservoir conditions. Such classification shall be determined and submitted to the Supervisor within six (6) months of the date of this Order.

B. Reclassification

A reservoir may be reclassified by the Supervisor, on his own initiative or upon application of an operator, during its productive life when information becomes available showing that such reclassification is warranted.

3. Oil and Gas Production Rates

A. Maximum Efficient Rate (MER)

The operator shall propose a maximum efficient rate (MER) for each producing reservoir based on sound engineering and economic principles. When approved at the proposed or other rate, such rate shall not be exceeded, except as provided in paragraph 4 of this Order.

(1) *Submittal of Initial MER.*—Within 45 days after the date of first production or such longer period as may be approved, the operator shall submit a Request for Reservoir MER (Form 9-1866) with appropriate supporting information. Within six months after the date of this Order, the operator shall submit a Request for Reservoir MER (Form 9-1866) with appropriate supporting information for each reservoir from which production commenced prior to the date of this Order.

(2) *Revision of MER.*—The operator may request a revision of an MER by submitting the proposed revision to the Supervisor on a Request for Reservoir MER (Form 9-1866) with appropriate supporting information. The operator shall obtain approval to produce at test rates which exceed an approved MER when such testing is necessary to substantiate an increase in the MER.

(3) *Review of MER.*—The MER for each reservoir will be reviewed by the operator annually, or at such other required or approved interval of time. The results of the review, with all current supporting information shall be submitted on a Request for Reservoir MER (Form 9-1866).

(4) *Effective Date of MER.*—The effective date of a MER, or revision thereof, will be determined by the Supervisor and shown on a Request for Reservoir MER (Form 9-1866) when the MER is approved. The effective date for an initial MER shall be the first day following the completion of an approved testing period. The effective date for a revised MER shall be the first day following the completion of an approved testing period, or if testing is not conducted, the date the revision is approved.

B. Maximum Production Rate (MPR)

The operator shall propose a maximum production rate (MPR) for each producing well completion in a reservoir together with full information on the method used in its determination. When an MPR has been approved for a well completion, that rate shall not be exceeded, except as provided in paragraph 4 of this Order. The MPR shall be based on well tests and any limitations imposed by (1) well tubing, safety equipment, artificial lift equipment, surface back pressure, and equipment capacity; (2) sand producing problems; (3) producing gas-oil and water-oil ratios; (4) relative structural position of the well with respect to gas-oil or water-oil contacts; (5) position of perforated interval within total production zone; and (6) prudent operating practices. The MPR established for each well completion shall not exceed 110 percent of the rate demonstrated by a well test unless justified by supporting information.

(1) *Submittal of Initial MPR.*—Within six months after the date of this Order, the operator shall submit a Request for Well Maximum Production Rate (MPR) (Form 9–1867), with the results of the potential test on a Well Potential Test Report (Form 9–1868). Thereafter, the operator shall have 30 days from the date of first continuous production within which to conduct a potential test, as specified under subparagraphs 5.B and 6.B of this Order, on all new and reworked well completions. Within 15 days after the date of the potential test, the operator shall submit a proposed MPR for the individual well completion on a Request for Well Maximum Production Rate (MPR) (Form 9–1867), with the results of the potential test on a Well Potential Test Report (Form 9–1868). Extension of the 30-day test period may be granted. The effective date for any approved initial MPR shall be the first day following the test period. During the 30-day period allowed for testing, or any approved extensions thereof, the operator may produce a new or reworked well completion at rates necessary to establish the MPR. The operator shall report the total production obtained during the test period and approved extensions thereof, on the Well Potential Test Report (Form 9–1868).

(2) *Revision of MPR Increase.*—If necessary to test a well completion at rates above the approved MPR to determine whether the MPR should be increased, notification of intent to test the well at such higher rates, not to exceed a stated maximum rate during a specified test period, shall be filed with the Supervisor. Such tests may commence on the day following the date of filing notification, unless otherwise ordered by the Supervisor. If an operator determines that the MPR should be increased he shall submit, within 15 days after the specified test period, a proposed increased MPR on a Request for Well Maximum Production Rate (MPR) (Form 9–1867), and any other available data to support the requested revision, including the results of the potential test and the total production obtained during the test period on a Well Potential Test Report (Form 9–1868). Prior to approval of the proposed increased MPR, the operator may produce the well completion at a rate not to exceed the proposed increased MPR of the well. The effective date for any approved increased MPR shall be the first day following the test period. If testing rates or increased MPR rates result in production from the reservoir in excess of the approved MER, this excess production shall be balanced by under production from the reservoir under the provisions of subparagraph 4.B of this Order.

(3) *Revision of MPR Decrease.*—When the quarterly test rate for an oil well completion or the semi-annual test rate for a gas well completion required under subparagraphs 5.C and 6.C of this Order is less than 90 percent of the existing approved MPR for the well, a new reduced MPR will be established automatically for that well completion equal to 110 percent of the test rate submitted. The effective date for the new MPR for such well completion shall be the first day of the quarter following the required date of submittal of periodic well-test results under subparagraphs 5.C and 6.C of this Order. Also, the operator may notify the Supervisor on a Request for Well Maximum Production Rate (MPR) (Form 9–1867) of, or the Supervisor may require, a downward revision of a well MPR at any time when the well is no longer capable of producing its approved MPR on a sustained basis. The effective date for such reduced MPR for a well completion shall be the first day of the month following the date of notification.

(4) *Continuation of MPR.*—If submittal of the results of a quarterly well test for an oil completion or a semi-annual well test for a gas well completion, as provided for in subparagraphs 5.C and 6.C of this Order, cannot be timely, continuation of production under the last approved MPR for the well may be authorized, provided an extension of time in which to submit the test results is requested and approved in advance.

(5) *Cancellation of MPR.*—When a well completion ceases to produce, is shut-in pending workover, or any other condition exists which causes the assigned MPR to be no longer appropriate, the operator shall notify the Supervisor accordingly on a Request for Well Maximum Production Rate (MPR) (Form 9–1867), indicating the date of last production from the well, and the MPR will be canceled. Reporting of temporary shut-ins by the operator for well maintenance, safety conditions, or other normal operating conditions is not required, except as is necessary for completion of the Monthly Report of Operations (Form 9–152).

C. *MER and MPR Relationship*

The withdrawal rate from a reservoir shall not exceed the approved MER and may be produced from any combination of well completions subject to any limitations imposed by the MPR established for each well completion. The rate of production from the reservoir shall not exceed the MER although the summation of individual well MPR's may be greater than the MER.

4. *Balancing of Production*

A. *Production Variances*

Temporary well production rates, resulting from normal variations and fluctuations exceeding a well MPR or reservoir MER shall not be considered a violation of this Order, and such production may be sold or transferred pursuant to paragraph 8 of this Order. However, when normal variations and fluctuations result in production in excess of a reservoir MER, any operator who is overproduced shall balance such production in accordance with subparagraph 4.B below. Such operator shall advise the Supervisor of the amount of such excess production from the reservoir for the month at the same time as Form 9–152 is filed for that month.

B. *Balancing Periods*

As of the first day of the month following the month in which this Order becomes effective, all reservoirs shall be considered in balance. Balancing periods for overproduction of a reservoir MER shall end on January 1, April 1, July 1, and October 1 of each year. If a reservoir is produced at a rate in excess of the MER for any month, the operator who is overproduced shall take steps to balance production during the next succeeding month. In any event, all overproduction shall be balanced by the end of the next succeeding quarter following the quarter in which the overproduction occurred. The operator shall notify the Supervisor at the end of the month in which he has balanced the production from an overproduced reservoir.

C. *Shut-in for Overproduction*

Any operator in an overproduction status in any reservoir for two successive quarters which has not been brought into balance within the balancing period shall be shut-in from that reservoir until the actual production equals that which would have occurred under the approved MER.

D. *Temporary Shut-in*

If, as the result of storm, hurricanes, emergencies, or other conditions peculiar to offshore operations, an operator is forced to curtail or shut-in production from a reservoir, the Supervisor may, on request, approve makeup of all or part of this production loss.

5. *Oil Well Testing Procedures*

A. *General*

Tests shall be conducted for not less than four consecutive hours. Immediately prior to the 4-hour test period, the well completion shall have produced under stabilized conditions for a period of not less than six consecutive hours. The 6-hour pretest period shall nor begin until after recovery of a volume of fluid equivalent to the amount of fluids introduced into the formation for any purpose. Measured gas volumes shall be adjusted to the standard conditions of the 12.025 psia and 60° F. for all tests. When orifice meters are used, a specific gravity shall be obtained or estimated for the gas and a specific gravity correction factor applied to the orifice coefficient. The Supervisor may require a prolonged test or retest of a well completion if such test is determined to be necessary for the establishment of a well MPR or a reservoir MER. The Supervisor may approve test periods of less than four hours and pretest stabilization periods of less than six hours for well completions, provided that test reliability can be demonstrated under such procedures.

B. *Potential Test*

Test data to establish or to increase an oil well MPR shall be submitted on a Well Potential Test Report (Form 9–1868). The total production obtained from all tests during the test period shall be reported on such form.

C. *Quarterly Test*

Tests shall be conducted on each producing oil well completion quarterly, and test results shall be submitted on a Quarterly Oil Well Test Report (Form 9–1869). Testing periods and submittal dates shall be as follows:

Testing period	Latest date for submittal of test results	For quarter beginning
Sept. 11-Dec. 10	Dec. 10	Jan. 1.
Dec. 11-Mar. 10	Mar. 10	Apr. 1.
Mar. 11-June 10	June 10	July 1.
June 11-Sept. 10	Sept. 10	Oct. 1.

There shall be a minimum of 45 days between quarterly tests for an oil well completion.

6. *Gas Well Testing Procedures*

A. *General*

Testing Procedures for gas well completion shall be the same as those specified for oil well completions in subparagraph 5.A except for the initial test which shall be a multi-point backpressure test as described in paragraph 6.D.

B. *Potential Test*

Test data to establish or to increase a gas well MPR shall be submitted on a Well Potential Test Report (Form 9-1868).

C. *Semi-annual Test*

Tests shall be conducted on each producing gas well completion semi-annually, and test results shall be submitted on a Semi-annual Gas Well Test Report (Form 9-1870). Testing periods and submittal dates shall be as follows:

Testing period	For submittal of test results	For semiannual period beginning
June 11-Dec. 10	Dec. 10	Jan. 1.
Dec. 11-June 10	June 10	July 1.

There shall be a minimum of 90 days between semi-annual tests for a gas well completion.

D. *Back-Pressure Tests*

A multi-point back-pressure test to determine the theoretical open-flow potential of gas wells shall be conducted within thirty days after connection to a pipeline. If bottom-hole pressures are not measured, such pressures shall be calculated from surface pressures using the method, or other similar method, found in the Interstate Oil Compact Commission (IOCC) Manual of Back-Pressure Testing of gas wells. The results of all back-pressure tests conducted by the operator shall be filed with the Supervisor, including all basic data used in determining the test results. The Supervisor may waive this requirement if multi-point back-pressure test information has previously been obtained on a representative number of wells in a reservoir.

7. *Witnessing Well Tests*

The Supervisor may have a representative witness any potential or periodic well tests on oil and gas well completions. Upon request, an operator shall notify the appropriate District office of the time and date of well tests.

8. *Sale or Transfer of Production*

Oil and gas produced pursuant to the provisions of this Order, including test production, may be sold to purchasers or transferred as production authorized for disposal hereunder.

9. *Bottom-Hole Pressure Tests*

Static bottom-hole pressure test shall be conducted annually on sufficient key wells to establish an average resrevoir pressure in each producing reservoir unless a different frequency is approved. The operator may be required to test specific wells. Results of bottom-hole pressure tests shall be submitted within 60 days after the date of the test.

10. *Flaring and Venting of Gas*

Oil- and gas-well gas shall not be flared or vented, except as provided herein.

A. Small-Volume or Short-Term Flaring or Venting

Oil- and gas-well gas may be flared or vented in small volumes or temporarily without the approval of the Supervisor in the following situations:

(1) *Gas Vapors.*—When gas vapors are released from storage and other low pressure production vessels if such gas vapors cannot be economically recovered or retained.

(2) *Emergencies.*—During temporary emergency situations, such as compressor or other equipment failure, or the relief of abnormal system pressures.

(3) *Well Purging and Evaluation Tests.*—During the unloading or cleaning up of a well and during drillstem, producing, or other well evaluation tests not exceeding a period of 24 hours.

B. Approval for Routine or Special Well Tests

Oil- and gas-well gas may be flared or vented during routine and special well tests, other than those described in paragraph A above, only after approval of the Supervisor.

C. Gas-Well Gas

Except as provided in A and B above, gas-well gas shall not be flared or vented.

D. Oil-Well Gas

Except as provided in A and B above, oil-well gas shall not be flared or vented unless approved by the Supervisor. The Supervisor may approve an application for flaring or venting of oil-well gas for periods not exceeding one year if (1) the operator has initiated positive action which will eliminate flaring or venting, or (2) the operator has submitted an evaluation supported by engineering, geologic, and economic data indicating that rejection of an application to flare or vent the gas will result in an ultimate greater loss of equivalent total energy than could be recovered for beneficial use from the lease if flaring or venting were allowed.

E. Content of Application

Applications under paragraph D above for existing operations, as of the date of this Notice, shall be filed within three months from the effective date of this Order. Applications under paragraph D(2) above shall include all appropriate engineering, geologic, and economic data in an evaluation showing that absence of approval to flare or vent the gas will result in premature abandonment of oil and gas production or curtailment of lease development. Applications shall include an estimate of the amount and value of the oil and gas reserves that would not be recovered if the application to flare or vent were rejected and an estimate of the total amount of oil to be recovered and associated gas that would be flared or vented if the application were approved.

11. *Disposition of Gas*

The disposition of all gas produced from each lease shall be reported monthly on, or attached to, Form 9–152. The report shall be submitted in the following manner:

	Oil-well gas (MCF)	Gas-well gas (MCF)
Sales		
Fuel		
Injected [1]		
Flared		
Vented		
Other (specify)		
Total		

[1] Gas produced from the lease and injected on or off the lease.

12. Multiple and Selective Completions

A. Number of Completions

A well bore may contain any number of producible completions when justified and approved.

B. Numbering Well Completions

Well completions made after the date of this Order shall be designated using numerical and alphabetical nomenclature. Once designated as a reservoir, or commingled reservoirs completion, the well completion number shall not change. Appendix A contains a detailed explanation of procedures for naming well completions.

C. Packer Tests

Multiple and selective completions shall be equipped to isolate the respective producing reservoirs. A packer test or other appropriate reservoir isolation test shall be conducted prior to or immediately after initiating production and annually thereafter on all multiply completed wells. Should the reservoirs in any multiply completed well become intercommunicative the operator shall make repairs and again conduct, reservoir isolation tests unless some other operational procedure is approved. The results of all tests shall be submitted on a Packer Test (Form 9–1871) within 30 days after the date of the test.

D. Selective Completions

Completion equipment may be installed to permit selective reservoir isolation or exposure in a well bore through wireline or other operations. All selective completions shall be designated in accordance with subparagraph 12.B when the application for approval of such completions is filed.

E. Commingling

Commingling of production from two or more separate reservoirs within a common well bore may be permitted if i is determined that, collectively, the ultimate recovery will not be decreased. An application to commingle hydrocarbons from multiple reservoirs within a common well bore shall be submitted for approval and shall include reservoir engineering data, and a schematic diagram of well equipment. For all competitive reservoirs, notice of the application shall be sent by the applicant to all other operators of interest in the reservoirs prior to submitting the application to the Supervisor. The application shall specify the well completion number to be used for subsequent reporting purposes.

13. Gas-Cap Well Completions

All existing and future wells completed in the gas cap of a reservoir which has been classified and approved as an associated oil reservoir shall be shut-in until such time as the oil is depleted or the reservoir is reclassified as a gas reservoir; provided, however, that production from such wells may be approvide when (1) it can be shown that such gas-cap production would not lead to waste of oil and gas, or (2) when necessary to protect correlative rights unless it can be shown that this production will lead to waste of oil and gas.

14. Location of Wells

A. General

The location and spacing of all exploratory and development wells shall be in accordance with approved programs and plans required in 30 CFR 250.17 and 250.34. Such location and spacing shall be determined independently for each lease or reservoir in a manner which will locate wells in the optimum structural position for the most effective production of reservoir fluids and to avoid the drilling of unnecessary wells.

B. Distance from Property Line

An operator may drill exploratory or development wells at any location on a lease in accordance with approved plans; provided that no well drilled and completed after the date of this Order in which the completed interval is less than 200 feet from a property line shall be produced unless approved by the Supervisor. An operator requesting approval to produce a well in which the completed interval is located closer than 200 feet from a property line shall furnish the Supervisor with letters expressing acceptance or objection from operators of offset properties.

15. Enhanced Oil and Gas Recovery Operations

Operators shall timely initiate enhanced oil and gas recovery operations for all competitive and noncompetitive reservoirs where such operations would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles. A plan for such operations shall be submitted with the results of the annual MER review as required in paragraph 3A(3) of this Order.

16. Competitive Reservoir Operations

Development and production operations in a competitive reservoir may be required to be conducted under either pooling and drilling agreements or unitization agreements when the Conservation Manager determines, pursuant to 30 CFR 250.50 and delegated authority, that such agreements are practicable and necessary or advisable and in the interest of conservation.

A. Competive Reservoir Determination

The Supervisor shall notify the operators when he has made a preliminary determination that a reservoir is competitive as defined in this Order. An operator may request at any time that the Supervisor make a preliminary determination as to whether a reservoir is competitive. The operators, within thirty (30) days of such preliminary notification or such extension of time as approved by the Supervisor, shall advise of their concurrence with such determination, or submit objections with supporting evidence. The Supervisor will make a final determination and notify the operators.

B. Development and Production Plans

When drilling and/or producing operations are conducted in a competitive reservoir, the operators shall submit for approval a plan governing the applicable operations. The plan shall be submitted within ninety (90) days after a determination by the Supervisor that a reservoir is competitive or within such extended period of time as approved by the Supervisor. The plan shall provide for the development and/or production of the reservoir, and may provide for the submittal of supplemental plans for approval by the Supervisor.

(1) *Development Plan.*—When a competitive reservoir is still being developed or future development is contemplated, a development plan may be required in addition to a production plan. This plan shall include the information required in 30 CFR 250.34. If agreement to a joint development plan cannot be reached by the operators, each shall submit a separate plan and any differences may be resolved in accordance with paragraph 17 of this Order.

(2) *Production Plan.*—A joint production plan is required for each competitive reservoir. This plan shall include (a) the proposed MER for the reservoir; (b) the proposed MPR for each completion in the reservoir; (c) the percentage allocation of reservoir MER for each lease involved; and (d) plans for secondary recovery or pressure maintenance operations. If agreement to a joint production plan cannot be reached by the operators, each shall submit a separate plan, and any differences may be resolved in accordance with paragraph 17 of this Order.

C. Unitization

The Conservation Manager shall determine when conservation will be best served by unitization of a competitive reservoir, or any reservoir reasonably delineated and determined to be productive, in lieu of a development and/or production plan or when the opeerators and lessees involved have been unable to voluntarily effect unitization. In such cases, the Conservation Manager may require that development and/or production operations be conducted under an approved unitization plan. Within six (6) months after notification by the Conservation Manager that such a unit plan is required, or within such extended period of time as approved by the Conservation Manager, the lessees and operators shall submit a proposed unit plan for designation of the unit area and approval of the form of agreement pursuant to 30 CFR 250.51.

17. Conferences, Decisions and Appeals

Conferences with interested parties may be held to discuss matters relating to applications and statements of position filed by the parties relating to operations conducted pursuant to this Order. The Supervisor or Conservation Manager may call a conference with one or more, or all, interested parties on his own initiative or at the request of any interested party. All interested parties shall be served with copies of the Supervisor's or Conservation Manager's decisions. Any interested party may appeal decisions of the Supervisor or Conservation Manager pursuant to 30 CFR 250.81. Decisions of the Supervisor or Conservation Manager shall remain in effect and shall not be suspended by reason of any appeal, except as provided in that regulation.

F. J. SCHAMBECK,
Oil and Gas Supervisor, Pacific Area.

Approved:

RUSSELL G. WAYLAND,
Chief, Conservation Division.

[OCS Order No. 11]

APPENDIX A

Subparagraph 12.B "*Numbering Well Completions.* Well completions made after the date of this Order shall be designated using numerical and alphabetical nomenclature. Once designated as a reservoir or commingled reservoirs completion, the well completion number shall not change. . ."

The intent of this Subparagraph is not necessarily to change the existing well completion names but to change the method of naming well completions after the effective date of this Order in order to insure that a completion in a given reservoir(s) and a specific well bore will be assigned a unique name and will retain the name permanently. For further clarification, the following guidelines and examples are offered:

1. Each well bore will have a distinct, permanent number.
2. Each reservoir or commingled reservoirs completion in a well bore will have a unique permanent designation which includes the well bore number in its nomenclature.
3. For the purpose of this Subparagraph, a "completion" is defined as all perforations in a given reservoir(s) in a specific well bore and is not necessarily associated with a tubing string or strings.
4. If more than one completion is made in a well bore, an alphabetical suffix must be used in the nomenclature to differentiate between completions.
5. An alphabetical prefix may be utilized to designate the platform from which the well will be produced.

Example No. 1.—The first well drilled from the A Platform is a single completion: "Well No. A-1." (Should an operator wish to use an alphabetical suffix with a single completion, he may do so.)

Example No. 2.—A well drilled by a mobile rig need not carry an alphabetical prefix: "Well No. 1." (If the well is later connected to and produced from a production platform, the well shall be redesignated to reflect an alphabetical prefix.)

Example No. 3.—The second well drilled from the A Platform is a triple completion: First Completion, "A-2"; Second Completion, "A-2-D"; Third Completion, "A-2-T." (In the above example, the above example, the letters "D" and "T" were used in naming the second and third completions utilizing current industry practice, although the intent is not to restrict operators to the use of these particular alphabetical suffixes. Any alphabetical suffix may be used as long as it is unique to the completion in that reservoir or commingled reservoirs.

Example. No. 4.—The drawing is shown to illustrate the fact once a completion in a specific well bore is designated in a given reservoir(s), it will retain that name permanently. Let us consider the A-2 completion shown in Example No. 3. Should a recompletion be made in a different reservoir(s) at a later date, it shall be renamed; however, the production from the reservoir(s) associated with the original A-2 completion will always be identified with the A-2 completion. Once the A-2 completion in the 10,000′ sand is squeezed and plugged off and the recompletion made to the 7,000′ sand, the completion in the 7,000′ sand would be designated A-2-A (or some other alphabetical suffix other than "D" or "T" presently associated with other completions in the 9,000′ and 8,000′ sands).

The Sundry notice (Form 9-331) submitted to obtain approval for the workover shall be the vehicle for naming the new completion.

Example No. 5.—If the A-2 completion in Example No. 4 had been recompleted from the 10,000′ sand to the 9,000′ sand (where the A-2-D is currently completed), the completion would still be named A-2-D as both tubing strings would be considered one completion for purposes of this Order.

[OCS Order No. 12, effective Dec. 1, 1974]

U.S. DEPARTMENT OF THE INTERIOR, PACIFIC AREA

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, PACIFIC AREA

Public inspection of records

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.97 and 43 CFR 2.2. Section 250.97 of 30 CFR provides as follows:

"*Public Inspection of Records.*—Geological and geophysical interpretations, maps, and data required to be submitted under this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect or until such time as the Supervisor determines that release of such information is required and necessary for the proper development of the field or area."

Section 2.2 of 43 CFR provides in part as follows:

"*Determinations as to Availability of Records.*—(a) Section 552 of Title 5, U.S. Code, as amended by Public Law 90–23 (the act codifying the 'Public Information Act') requires that identifiable agency records be made available for inspection. Subsection (b)[1] of section 552 exempts several categories of records from the general requirements but does not require the withholding from inspection of all records which may fall within the categories exempted. Accordingly, no request made of a field office to inspect a record shall be denied unless the head of the office or such higher field authority as the head of the bureau may designate shall determine (1) that the record falls within one or more of the categories exempted and (2) either that disclosure is prohibited by statute or Executive Order or that sound grounds exist which require the invocation of the exemption. A request to inspect a record located in the headquarters office of a bureau shall not be denied except on the basis of a similar determination made by the head of the bureau or his designee, and a request made to inspect a record located in a major organizational unit of the Office of the Secretary shall not be denied except on the basis of a similar determination by the head of that unit. Officers and employees of the Department shall be guided by the 'Attorney General's Memorandum on the Public Information Section of the Administrative Procedure Act' of June 1967.

"(b) An applicant may appeal from a determination that a record is not available for inspection to the Solicitor of the Department of the Interior, who may exercise all of the authority of the Secretary of the Interior in this regard. The Deputy Solicitor may decide such appeals and may exercise all of the authority of the Secretary in this regard."

The operator shall comply with the requirements of this Order. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. Availability of Records Filed on or After the Effective Date of This Order

It has been determined that certain records pertaining to leases and wells in the Outer Continental Shelf and submitted under 30 CFR 250 shall be made available for public inspection, as specified below, in the Area office, Los Angeles, California.

A. Form 9–152—Monthly Report of Operations

All information contained in this form shall be available except the information required in the Remarks column.

B. Form 9–330—Well Completion or Recompletion Report and Log

(1) Prior to commencement of production, all information contained on this form shall be available except Item 1a, Type of Well; Item 4, Location of Well,

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[1] Subsection (b) of section 552 provides that:
"(b) This section does not apply to matters that are—
"* * *
"(4) Trade secrets and commercial or financial information obtained from a person and privileged or confidential;
"* * *
"(9) Geological and geophysical information and data, including maps, concerning wells."

At top prod. interval reported below; Item 22, If Multiple Compl., How Many; Item 24, Producing Interval; Item 26, Type Electric and Other Logs Run; Item 28, Casing Record; Item 29, Liner Record; Item 30, Tubing Record; Item 31, Perforation Record; Item 32, Acid, Shot, Fracture, Cement Squeeze, etc.; Item 33, Production; Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(2) After commencement of production, all information shall be available except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers.

(3) If production has not commenced after an elapsed time of five years from the date of filing, Form 9-330 as required in 30 CFR 250.38(b), excluding the total of such time that operations and production are suspended by direction of the Secretary of the Interior or his duly authorized representative, and further excluding the total of such time that operations and production are stopped or prohibited by Court order, all information contained on this form shall be available except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers. Within 90 days prior to the end of the 5-year period, exclusive, of exceptions noted above, the lessee or operator shall file a Form 9-330 containing all information requested on the form, except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers, to be made available for public inspection. Objections to the release of such information may be submitted with the completed Form 9-330.

C. Form 9-331—Sundry Notices and Report on Wells

(1) When used as a "Notice of Intention to" conduct operations, all information contained on this form shall be available except Item 4, Location of Well, At top prod. interval; and Item 17, Describe Proposed or Completed Operations.

(2) When used as a "Subsequent Report of" operations, and after commencement of production, all information contained on this form shall be available except information under Item 17 as to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.

D. Form 9-331C—Application for Permit to Drill, Deepen or Plug Back

All information contained on this form and location plat attached thereto, shall be available except Item 4, Location of Well, at proposed prod. zone; and Item 23, Proposed Casing and Cementing Program.

E. Form 9-1869—Quarterly Oil Well Test Report

All information contained on this form shall be available.

F. Form 9-1870—Semi-Annual Gas Well Test Report

All information contained on this form shall be available.

G. Multi-Point Back Pressure Test Report

All information contained on the form used to report the results of required multi-point back pressure test of gas wells shall be available.

H. Sales of Lease Production

Information contained on monthly Geological Survey computer printout showing sales volumes value, and royalty of production of oil, condensate, gas and liquid products, by lease, shall be made available.

2. Filing of Reports

All reports on Form 9-152, 9-330, 9-331, 9-331C, 9-1869, 9-1870, and the forms used to report the results of multi-point back pressure tests, shall be filed in accordance with the following: All reports submitted on these forms after the effective date of this Order shall include a copy with the words "Public Information" shown on the lower right-hand corner. All items on the form not marked "Public Information" shall be completed in full; and such forms, and all attachments thereto, shall not be available for public inspection. The copy marked "Public Information" shall be completed in full, except that the items described in 1.A., B., C., and D. above, and the attachments relating to such items, may be excluded. The words "Public Information" shall be shown on the lower right-hand corner of this set. This copy of the form shall be made available for public inspection.

3. Availability of Records Filed Prior to December 1, 1974

Information filed prior to December 1, 1974, on Forms 9-152, 9-330, 9-331, and 9-331C is not in a form which can be readily made available for public inspection.

Requests for information on these forms shall be submitted to the Supervisor in writing and shall be made available in accordance with 43 CFR Part 2.

4. Availability of Inspection Records

All accident investigation reports, pollution incident reports, facilities inspection data, and records of enforcement actions are also available for public inspection.

F. J. SCHAMBECK,
Oil and Gas Supervisor, Pacific Area.

Approved: November 21, 1974.

RUSSELL G. WAYLAND,
Chief, Conservation Division.

64-969—76——24

Appendix XIX.—Summary Tables and References to Studies of the Biological Effects of Petroleum in the Marine Environment

(From the National Academy of Sciences 1975 study entitled, "Petroleum in the Marine Environment")

TABLE 4-1.—A SUMMARY OF SEVERAL MAJOR OIL SPILLS FOLLOWED BY STUDIES OF THEIR BIOLOGICAL IMPACT

Date of spill and source and location	Type and amount of oil (barrels)	Shoreline affected (miles)	Localities studied	Species identified	Sampling method	Biological damage	Reference
March 1957: "Tampico Maru," Baja California, Mexico.	Diesel oil, 60,000	2	Intertidal and subtidal.	Larger visible plants and animals.	Qualitative, quantitative macrocystis counts.	Nearly total devastation immediately, luxuriant growth of seaweed developed within months; biota 90 percent restored after 3 or 4 yr, although relative abundance of certain species still somewhat changed after 12 yr.	North, et al., 1964; Mitchell, et al., 1970.
July 1962: "Argea Prima," Guayanilla Harbor, P.R.	Crude oil, 70,000		Mangrove shores; intertidal and subtidal.	Blue-green algae	Qualitative	Extensive damage: high mortalities among many shallow water and shore-dwelling organisms, including a wide variety of vertebrates; also extensive damage to intertidal and sublittoral algae and mangrove habitat.	Diaz-Piferrer, 1962.
January 1967: "Chryssi P. Goulandris," Milford Haven, England.	Crude oil, $\geq$1,800		Intertidal salt marsh; intertidal rocky shore.	Grasses	Semiquantitative rocky shore transect; quantitative studies of grasses.	Most damage to intertidal organisms; gastropod molluscs badly affected, also barnacles and sea anemones on a number of shores; no apparent damage to algae.	Cowell, 1969; Nelson-Smith, 1968.
March 1967: "Torrey Canyon," S.W. England.	860,000*		Intertidal rocky shores and sand beach.	Larger visible animals only	Semiquantitative rocky shore transects; qualitative beach and subtidal surveys; quantitative algal counts.	Very high mortalities of intertidal shore life, mostly due to use of toxic emulsifiers; many invertebrates and algae killed on shores; fisheries and plankton apparently unaffected; estimated 10,000 birds killed.	Bellamy, et al., 1967; Smith, 1968.
September 1967: "R. C. Stoner," Wake Island.	Aviation gas, J-P4 jet fuel, A-1 turbine oil, and Bunker C oil 126,000.		Intertidal and subtidal.	Large visible invertebrates	Qualitative	Many dead fish stranded on shores; also abundant dead molluscs, sea-urchins, and crabs.	Gooding, 1968.

March 1968: "Ocean Eagle," San Juan Harbor, P.R.	Crude oil, 83,000		Intertidal rocky shore.	15 large species	do	Many subtidal and intertidal organisms killed or damaged by oil or oil and emulsifier, including molluscs, crustaceans, and algae, although subsequent recovery good; 10 species of fish found dead or in state of stress.	Cerame-Vivas, 1968.
April 1968: "Esso Essen," South Africa.	Crude oil 20,000–28,000.		Intertidal and subtidal.	No species identifications, observations on larger organisms.	do	High mortalities of sandhoppers (amphipods) but otherwise little damage on shores; high bird mortalities.	Stander and Ventner 1968.
December 1968: "Witwater," Galeta Island, Canal Zone.	Diesel and bunker C oil, 20,000.		Rocky intertidal, coral reef, sandy intertidal mangroves.	Uca, mangrove species, four coral species.	1 quantitative sand sample for meiofauna; otherwise qualitative.	On rocky shores, extensive mortality of supralittoral vegetation and tide pool life; on sandy beaches, great population decreases among meiofauna, especially crustaceans; many young mangroves killed in swamp areas, also algae and many invertebrates; coral reefs apparently unharmed.	Rutzler and Sterrer, 1970.
January 1969: Well A-21, Santa Barbara Channel.	Crude oil, 33,000*	40	Intertidal and subtidal.	Subtidally: selected polychaete families, ophiuroids, and molluscs not including smaller polychaetes and amphipods; intertidally: visible rocky shore species and 195 species retained by 1.5-mm screens in sandy areas.	Grab sample, qualiative at species level; quantitative for biomass line transects on rocky shores; 1/100 m^2 samples on beaches.	High mortalities of intertidal organisms covered with oil; about 3,600 birds killed; no apparent effects on fish and plankton; no directly attributable damaging effects of oil on large marine mamals or on benthic fauna; area recovering well within a year.	Cimberg et al., 1973; Fauchald, 1971; Foster, et al., 1971a, b; Nicholson and Cimberg, 1971; Straughan, 1972.
September 1969: "Florida," West Falmouth, Mass.	No. 2 fuel oil, 4,500*	3	Intertidal mud and sand flats; subtidal to 10 mm.	All animals 0.247 mm, excluding nematodes, copepods; ostracods and unicellular organisms, including smaller polychaetes and amphipods.	Quantitative transects.	Severe pollution of sublittoral zone, with 95 percent kill of all fauna, including many fish, worms, molluscs, crabs, lobsters, and other crustaceans and invertebrates; local shellfish industry severely affected; Wild Harbor still closed to shellfish fishing in May 1974.	Blumer and Sass, 1972; Blumer, et al., 1970a,b.

APPENDIX XIX.—SUMMARY TABLES AND REFERENCES TO STUDIES OF THE BIOLOGICAL EFFECTS OF PETROLEUM IN THE MARINE ENVIRONMENT

(From the National Academy of Sciences 1975 study entitled, "Petroleum in the Marine Environment")

TABLE 4-1.—SUMMARY OF SEVERAL MAJOR OIL SPILLS FOLLOWED BY STUDIES OF THEIR BIOLOGICAL IMPACT—Continued

Date of spill and source and location	Type and amount of oil (barrels)	Shoreline affected (miles)	Localities studied	Species identified	Sampling method	Biological damage	Reference
February 1970: "Arrow" Chedabucto Bay.	Bunker C, 108,000*	12	Intertidal rocky shore; intertidal lagoon.	Common visible species on rocky shore and species 74 mm in lagoon samples.	Semiquantitative transects; 2 samples in lagoon.	Localized damage to intertidal life, where most mortalities were crabs, limpets, and algae, probably killed by smothering; local fish catches normal; about 2,300 birds killed; 5 mo after spill, subtidal flora and fauna healthy; fishing and lobstering normal.	Thomas, 1973; Navships, 1970.
January 1971: "Arizona Standard" and Oregon Standard," San Francisco Bay	Bunker C, 20,000*	60	Intertidal and subtidal rocky shore; intertidal sand beach.	31 larger species	Quantitative transect counts.	Some damage to shore life, mainly to acorn barnacles, limpets, mussels, and striped shore crabs; 3,600 birds killed; area nearly normal within 1 yr.	Chan, 1973.
February 1971: "Wafra," Cape Agulhas, South Africa.	Crude oil, 445,000	10	Intertidal rocky shores.	Larger intertidal rocky shore species.	Qualitative	Little damage to intertidal life; 1,135 black footed penguins found oiled.	Day, et al., 1971.
April 1971: March Point Dock Facility, Anacortes, Wash.	No. 2 fuel oil, 5,000	20	Intertidal beaches, rocky shores, subtidal.	Animals 4 mm in subtidal samples, visible epifauna in intertidal areas; fauna identified to major taxa only.	Quantitative grabs; quantitative intertidal transects.	Some oil on shores, damaging shellfish, limpets, crabs, clams and oysters; about 1,000 birds involved.	Watson, et al., 1971; Woodin, et al., 1973.
January 1972: "General M.C. Meigs," Wreck Cove, Washington coast	Navy special oil, 3,000*.	†300-500	Intertidal rocky shores.	37 species algae, specie animals not including smaller polychaetes and amphipods	Quantitative transects.	Urchins affected; plant community showed less of fronds and bleached thalli.	Clark, et al., 1973.

*Moore, Stephen F., et al., 1974. Potential biological effects of hypotetical oil discharges in the Atlantic coast and Gulf of Alaska. In Report to Council on Environmental Quality, MIT Sea Grant Program MITSG 74-19, Cambridge.

†Yards.

TABLE 4-2.—EVALUATION OF EXPERIMENTS AND OBSERVATIONS OF THE SUBLETHAL EFFECTS ON ORGANISMS BOTH OF POLLUTION AND OF OTHER ASSOCIATED ACTIVITIES OF THE PETROLEUM INDUSTRY

Group	Species	Reference	Type of petroleum product	Concentration	Effects and evaluation
A. Reproduction:					
1. Fecundity: Crustacea.	Pollicipes polymerus	Straughan, 1971	Crude oil, Santa Barbara blow-out field study		Inverse relationship between the fraction of adults brooding and the amount of oil on the adults (p 0.5); heavily and moderately oiled areas had no recruitment whereas settlement was recorded from all unoiled samples.
Mollusca	Mytilus edulis	Blumer et al., 1971	No. 2 fuel oil, West Falmouth spill field observations.		Gonads of mussels failed to develop in affected areas.
2. Fertilization and development: Marsh grass	Festuca rubra	Baker, 1971	Kuwait ("fresh," 10 percent distillate and 90 percent residue)	Seeds soaked in 5 ml of various oils for 1 h	Germination almost completely inhibited: experiments limited in scope, but related to field situation.
Polychaeta	Capitella capitata	Bellan et.al., 1972	Detergent ("low" toxicity polyethylene-glycol fatty acid).	0.01–10 ppm	Survival of young decreased; reduction in number of females laying eggs; most complete study of sublethal effects on reproduction; laboratory strain of this hardy species probably reflects extreme tolerance conditions
Fish	Gadus morrhua	Kuhnhold, 1970	Irania crude extracts paraffin based).	Aqueous extracts from 10^4, 10^3, 10^2 ppm total oil (author estimates 10^4 yields 10 ppm soluble hydrocarbons, 1 ppm may be more likely).	Eggs: "Some cases" were sublethal but embyros and larvae did not survive, apparently 10^3 ppm does not differ from control. Larvae: "Showed typical behavior symptoms in oil extracts: increased activity was followed by a reduction of swimming activity, which finally stopped .. which slowly deeped until the critical point' when no responses of the larvae were obtained even by touching or prodding"; time to "critical point" varies with age of larvae and amount of oil: 10^2 ppm not different from control (14-5.5 days for 1-10-day-old larvae); 10^3 ppm (8.4–4.5); 10^4 ppm (4.2-05.); "herring larvae were less, and plaice larvae more, resistant than cod"; "chemoreceptors seemed to be blocked very quickly at the first contact with oil"; insufficient quantification no measure of uncertainty; no chemical analysis
	Pleuronectes platessa	Wilson, 1970	BP1002	0-10 ppm	Larvae: "1/50 of 100 C_{50} (0.04-0.2 ppm BP1002) disrupt photoactic and feeding behavior (the ability of the larvae to capture prey items was significantly impaired)"; recovery in uncontaminated seawater in 1 to 3 days; ranges for control in photoactic response experiments not given; feeding results not documented

TABLE 4-2.—EVALUATION OF EXPERIMENTS AND OBSERVATIONS OF THE SUBLETHAL EFFECTS ON ORGANISMS BOTH OF POLLUTION AND OF OTHER ASSOCIATED ACTIVITIES OF THE PETROLEUM INDUSTRY—Continued

Group	Species	Reference	Type of petroleum product	Concentration	Effects and evaluation
A. Reproduction—Continued Lobster	Homarus americanus	Wells, 1972	Venezuelan crude	0.1, 1, 6, 10, and 100 (emulsions)	100 ppm lethal to all larval stages; 10 ppm; stages 1–3 more sensitive than stage 4. Long-term experiments with newly hatched larvae: 10 ppm: 9-day mean survival time; 6 ppm: longer time to 4th, longer than at lower concentrations; concentrations at which development was prolonged are too high to be important in the field.
B. Growth: Phytoplankton	Several diatoms and dinoflagellates.	Mironov, 1970		Concentrations of oil mixed with seawater (1.0 to 0.001 ml/l); effective concentration may be 0.1 ppm to 0.1 ppb.	No cell division or delayed cell division, compared with controls; dinoflagellates generally more susceptible than diatoms; no mention of type of oil in this work; no measure of concentration of soluble hydrocarbons; concentrations reported seem unrealistically low.
	Unspecified microalgae, Asterione llajaponica.	Aubert et al., 1969	Kerosene	3 ppm; 38 ppm	Depression of growth rate; concentration of soluble hydrocarbons unknown.
	Phaeodactylum tricornutum.	Lacaze, 1967; Nelson-Smith, 1973.	Kuwait crude	1 percent extracts, effective concentration may be 1 ppm.	Do.
	Chlorella vulgaris	Kauss et al., 1973	Aqueous extracts of several crude oils and outboard motor oil; 90 percent solutions of aqueous extracts used.	1 part oil to 20 parts water	Inhibition of growth varied from 5 percent to 41 percent after 2 days of exposure; after 10 days, cell yields were close to controls, suggesting inhibiting substance was eventually lost. After 2 days of cell growth, cell numbers were significantly lower in 25 percent, 50 percent, and 90 percent oil extracts than in control; concentrations of water-soluble hydrocarbons and comparison of oils unknown.
				25 to 500 ppm solutions of benzene; 25 to 250 ppm solutions of toluene; 100 ppm solutions of zylene; 3 to 27 ppm naphthalene.	Inhibition of growth of 1 to 2 days' duration (volatilization eventually reduced effect); minimum concentrations tested had an effect but are unrealistically high; lower concentrations should have been tested.
	Monochrysis lutheri	Strand et al., 1971	Kuwait crude; dispersant (holl. chem. 622) emulsions.	20 to 100 ppm	Inhibition of growth during 6 days of experiment at all concentrations tested; lowest concentrations had an effect, therefore, lower concentrations should have been studied; effect of crude-dispersant emulsion difficult to relate to other information.
	Phaesdactylum tricornutum, Skeletonema costatum, . Chlorella sp., Chlamydomonas sp.	Nurzi, 1973	Extracts of outboard motor oil, No. 6 fuel oil ,No. 2 fuel oil.	1 ppm	Inhibition of growth during 10 to 12 days incubation with No. 2 fuel oil only at 20 percent of extracted medium, stimulation of growth by crude and motor oil extracts; concentration of water-soluble hydrocarbons not determined, therefore, it is difficult to compare oils.

Plants	Distichlis maritima, Festuca rubra	Baker, 1971	Kuwait atmospheric residues		Treatment — Apply: Apr. 23, 1970, Harv.: June 10, 1970 — Apply: July 11, 1969, Harv: Aug. 27, 1969 Unoiled: 5.4±.8; 2.9±.4 4 l/m²: 7.8±1.4; 2.9±.7 8 l/m²: 11.7±.7; 1.6±.5 Results: increase in dry weight (g/25 cm quadrat) similar for F. rubra but stimulation not observed with Spartina anglica; experiments with "fresh" Kuwait reduce growth; numerous additional experiments reported; results not reported systematically, statistical significance included.
Mollusca	Crassostrea virginica	Mackin and Hopkins, 1961.	Locally produced crude	Spray	Sprayed directly on oysters weekly for 6 mo; no effect on growth or survival of adult oysters or spat.
			Heavy loss of crude by wild well; Port Sulfur, La.; started Jan. 17, 1956, oil not evident by March 1972.		No effect on growth, nor any difference in growth between experiment and controls for all size oysters.
	Grassostrea virginica	Mackin and Hopkins, 1961.	Bleedwater		Oysters in trays and bags at varying distances outfail; Effect: mortality at 50 to 75 ft; reduced growth and glycogen content at 75 to 150 ft; none beyond 150 ft.
	Littorina littorea	Perkins, 1970	BP1002	30 ppm	Significant inhibition of growth.
C. Metabolism: 1. Photosynthesis: Phytoplankton	Mixed natural samples	Gordon and Prouse, 1973.	Venezuelan crude No. 2 and No. 6 fuel oil.	10 to 200 μg/l (ppb)	Concentrations below 10 to 30 μg/l were on stimulate photosynthesis, while at concentrations between 60 and 200 μg/l, were somewhat suppressed below controls for all but No. 2 fuel oil which depressed photosynthesis to approximately 60 percent of controls at concentrations between 100 and 200 μg/l; environment in Bedford Basin: 0.5 to 60 μg/l; highest content (under slick): 800 μg/l.
	Monochrisis lutheri	Strand et al., 1971	Kuwait crude: dispersant (holl, chem. 622) emulsions.	1 to 1,000 ppm	Significant reduction of bicarbonate uptake at concentrations 50 ppm; effect of crude-dispersant emulsion difficult to relate to other information; only observations recorded; no data presented in this preliminary report.
	Chlamydomonas angulosa.	Kauss et al., 1973	Naphthalene	3 to 24 ppm	Almost complete reduction of bicarbonate uptake at concentrations as low as 3 ppm in stoppered flasks; when volitization permitted uptake rebounds; lowest concentration tested produced reduction; therefore, experiments at lower, probably more realistic, concentrations should have been conducted.

TABLE 4-2.—EVALUATION OF EXPERIMENTS AND OBSERVATIONS OF THE SUBLETHAL EFFECTS ON ORGANISMS BOTH OF POLLUTION AND OF OTHER ASSOCIATED ACTIVITIES OF THE PETROLEUM INDUSTRY—Continued

Group	Species	Reference	Type of petroleum product	Concentration	Effects and evaluation
C. Metabolism—Continued					
Kelp	Marcocystis pyrifera	North, 1965			
Lichen	Lichen pygmaea	Brown, 1972	Kuwait crude BP1002	0.1 to 100 ppm	Total ^{14}C fixation was affected by emulsifier at concentrations of 1 ppm and greater; 50 percent fixation below control at 100 ppm and near 0 fixation at 50 percent emulsifier—at higher concentrations tested, there is also an increase in carbohydrate leakage to the seawater from the licneh—also conducted experiments to test effects of aging oil and/or emulsifier but results gave either no differsame response as emulsifier and seawater, so oil was not the important toxicant; cites field studies which confirm lab results that emulsifier and not oil kills lichens; concludes that since aging didn't increase the toxicity of PB1002, then it is the surfactant and not the volatile solvent that is of significance in toxicity.
2. Respiration:					
Fish	Cyprinodon varie gatus, Lagodon thomboides, Micropogon undulatus.	Steel and Copeland, 1967	Petrochemical wastes	0.2 to 2.0 ppm in addition 0.4 to 4.0 phenol.	Claims respiratory inhibition at low concentration, then stimulation approaching TL 48 as general pattern; only 1 of the 3 species fit this pattern; insufficient acclimation; too high concentrations.
	Lagodon rhomboides	Wohlschlag and Cameron, 1967.	Petrochemical wastes	50 percent of wastewater	Depression of respiration much more severe at near-lethal temperatures than intermediate ones; water collected from Corpus Christi turning basin then diluted to ½; so achievable in the field; lack of confidence intervals.
Molluscs	Mytilus edulis, Modiolus demissus.	Gilfillan, 1973	Extract of midcontinent sweet crudes.	1 percent emuslion	Differential effects of salinity and oil on filtering rate and respiration; normal salinity: increasing oil produces erratic stimulation of respiration; depression of filtering rate above 1 percent extract; 21 ppt salinity increases respiration and increases filtering rate up to 10 percent extract, then a very rapid dropoff at higher concentrations of oil. 11 ppt: shutdown of activity; no additional effect of oil.

Fish	Juvenile Onchorhynchus tshanytsha (salmon) and Morone saxatilis (striped bass).	Brocksen and Bailey, 1973.	Benzene	5 and 10 ppm changed every 48 h.	Respiratory rate was increased during the early (24 to 48-h) period of exposure to both 5 and 10 ppm of benzene; after longer periods, respiration decreases back to near-control levels; when tested at daily intervals after exposure, found both fish species returned to control levels.
D. Behavior:					
Fish	Ictalurus natalis	Todd, 1972			Feeding unaffected; social behavior altered after 1 to 3 days and returned to normal in about 1 week; second additions after return to normal again disrupted social behavior.
	Notemigonus crysoleucas				No apparent effect on social behavior and/or feeding.
Crustacea	Homarus americanus	Atema and Stein, 1972	La Rosa crude and extracts thereof.		Change in feeding times (doubling of waiting time) and behavior caused by addition of 1:100,000 parts crude oil to water; soluble fractions giving same oil/water ratio had no effect; light and electron microscopy showed no change in morphology of odor receptors; response similar over 5-day period, although hydrocarbons' characteristics did change by "weathering"; experimentally good as possible, but long-term effects and recovery not considered; very difficult problem.
Gastropoda	Nassarius obsoletus	Jacobson and Boylan, 1973.	Kerosene extract	1 to 4 ppb	Significant reduction in attraction to oyster extract (0.31 ppm); significant reduction in attraction to scallop extract (3 ppm); analytically and statistically sound; experimental concentrations realistic to chronically polluted harbors and spill-affected areas.
Crustacea	Pachygrapsus crassipes	Kittredge, 1971	Crude oil (Sisquoc sand in California) dilutions (as low as 1:100) of diethyl ether extracts.		Inhibition of chemically mediated feeding and 6 pheromone responses in the presence of dilutions of crude oil extracts; response recovery in 3 to 6 days; quantification less than adequate, not statistically tested; method of extract preparation of questionable validity; concentration of hydrocarbons not known.
	Uca pugnax	Krebs, 1973	No. 2 fuel oil, West Falmouth spill, heavily and moderately oiled marshes.		Results were that male and females exhibited breeding display colors, and males exhibited threat posture even though the breeding season had been over; mortality was heavy in these areas; interpretations based on observational information only; little quantification and adequate control areas lacking.
Fish	Onchorhynchus gorbuschka (salmon).	Rice, 1973	Prudhoe Bay crude oil		Small fry are much more tolerant of oil and avoid it a mcuh higher concentrations than large fry; large fry: TLm 48 to 110 ppm, avoidance at 1.6 ppm. The speculation that this avoidance could disrupt migrations may be reasonable since such an effect has been reported for zinc pollution on Atlantic salmon.

TABLE 4-2.– EVALUATION OF EXPERIMENTS AND OBSERVATIONS OF THE SUBLETHAL EFFECTS ON ORGANISMS BOTH OF POLLUTION AND OF OTHER ASSOCIATED ACTIVITIES OF THE PETROLEUM INDUSTRY– Continued

Group	Species	Reference	Type of petroleum product	Concentration	Effects and evaluation
C. Histological changes:					
Fish	Menidia menidia	Gardner, 1972	Texas-Louisiana crude oil	1 l w/40 l seawater, then separate fractions (soluble and insoluble); exposed for 168 h.	Various types of histological abnormalities exhibited after exposure to both the soluble and insoluble fractions; largely chemoreceptor structures studies but also ventricular myocardium; no analyses of concentrations seen by fish; technique seems good, but tissue and water content of hydrocarbons needed.
Clam, fish	Mya arenaria, Menidia menidia.	Gardner et al., 1973	Texas-Louisiana crude oil and No. 2 fuel.	600 ppm	0.95 l crude oil mixed with 37.85 l seawater; after settling, oil on top (water-insoluble fraction) at 600 ppm used to expose Menidia, also water layer (water-soluble fraction) at 126 ml/l used on other groups of Menidia; some histological damage to chemoreceptors of fish but concentrations seen by fish not known; Mya arenaria collected and sectioned 4 mo after a spill of No. 2 fuel oil showed an increased incidence of gonadal tumors, compared with those collected from control area; all results indicative of possibly good technique but effect not well quantified and neither was content of hydrocarbons; other causes for tumors possible.
Mollusca	Crassostrea virginica	St. Amant, 1970	Dredging, etc., associated with petroleum extraction in *marshes of Louisiana coast.*		Activities have caused increased incursion of higher salinity water into marshes that formerly had *lower salinity; decreased oyster production.*
Benthos, Zooplankton Neuston.		Mackin, 1971	Brine effluents from 5 different oil fields; volume and characteristics differ widely.		Over a radius of approximately 400 ft, the effluence from Trinity Bay and Fisher's Reef fields affects the size and diversity of benthic communities; no other effect from other distances, other fields, or the zooplankton or neuston was found. A quite complete coverage of species and conducted over a 1-yr period; would be good if had hydrocarbon data.
Benthos		Reish, 1965	Refinery effluent		Bottom of L.A. harbor that received wastes from *refineries was either uninhabited or inhabited* only by Capitella capitata; after a part of region dredged, number of species increased, then rapidly declined again; correlated increase of carbon in the sediment; region studies limited to only a narrow channel near the source of the effluents; in addition, this part of the harbor received wastes from many other sources; not certain that the oil was actually responsible, nor how far and to what dilutions severe damage extended.

		Reish, 19.	Refinery effluent		By 1970, all L.A. refineries ceased discharging wastes or eliminated the oxygen depleting fraction; number of benthic species increased from 0 in 1954 at the four most heavily polluted stations to 4, 6, 10, 11 in November 1970; work sketchy, but does demonstrate that oil wastes definitely were responsible for the impoverished benthic fauna before abatement; no samples from greater distances to suggest the extent of the effect by refinery wastes.
Marsh	Spartina anglica community.	Baker, 1971	Refinery effluent hydrocarbon; characteristics not specified.	About 2ppm phenols	S. anglica gradually killed over 20-yr period, probably repeated coating by thin oil films; in creek blue-green algae have replaced filamentous greens (S. anglica will grow in soil samples and effluent water samples).
Marsh grasses		Baker, 1971	Successive spillage of Kuwait crude.		Results, ranking from least to most tolerant species: (1) shallow rooted plants with no or small food reserves (Suaeda maritima, Salicornia sp.); (2) shrubby perennials (Halimione portulacoides); (3) filamentous green algae (Ulothrix sp., Baucheria sp.); (4) perennials (Spartina townsendi, Juncus maritima, Puccinellia maritima, Festuca rubra, Agrostis stonifera); (5) perennials of rosette habit with large food reserves (Cochleraia sp., Glaux maritima, Artemisia maritima).
Various	Various	Crapp, 1971	Benthic Kuwait crude emulsifier BP1002.		Communities, hard substrates, Milford Haven: (a) same shores compared after 7 to 9 yr, only species changing were also changed elsewhere due to temperature changes over a large area; (b) field experiments crude oil had little detectable effect, but emulsifiers reduced herbivorous molluscs with the result that inner tidal algae increased; (c) stranded weathered crude, mechanical smothering of some inner tidal animals.
		Crapp, 1971; Baker, 1973.	Refinery effluents: phenol oils, etc.		Effluents poorly described, only "oil," "phenols," etc.; grazing snails reduced in numbers, particularly small ones, nearer (27 m) versus further (1960 m) from outfall; fucoid algae more abundant at nearer stations; prior to this refinery, the shore had few algae, mostly barnacles and limpets; same situation in 1970, 1972.

See footnotes at end of table.

TABLE 4-2.– EVALUATION OF EXPERIMENTS AND OBSERVATIONS OF THE SUBLETHAL EFFECTS ON ORGANISMS, BOTH OF POLLUTION AND OF OTHER ASSOCIATED ACTIVITIES OF THE PETROLEUM INDUSTRY– Continued

Group	Species	Reference	Type of petroleum product	Concentration	Effects and evaluation
Invertebrates		Nicholson and Cimberg, 1971.	Santa Barbara crude and natural seep.		Coal Oil Point had a less varied invertebrate fauna than other comparable areas along the coast of Southern California; suggested that chronic exposure to the nearby natural seep might account for the low diversity by eliminating sensitive kinds; sampling along single line transects inappropriate for assessing the variety of organisms that inhabit a locality; Onuf added 21 more species to their list of 24 in 1½ h.
Mussels	Mytilus californianus	Kanter et al., 1971	Crude	1,000, 10,000, 100,000 ppm	Coal Oil Point mussels were more resistant than ones from other areas, suggesting that chronic exposure leads to selection for tolerant forms; alternative that inherent physiological variability between populations may account for differences in oil tolerance is not eliminated and is suggested by the 10 to 100-fold difference in tolerance of mussels from 2 nonseep area samples.
D. Behavior (continued)					
Fish	Gulf of Mexico sp	Bechtel & Copeland, 1970.	Petrochemical wasts	Different percent Houston Ship Channel water.	Claims that percent polluted water is a good predictor of species diversity; unfounded because confounded with salinity; to convincingly demonstrate that oil pollution responsible for decreased diversity, compare with samples covering a similar range of salinites in an unpolluted control bay.
Fish, shrimp	do	Spears, 1971	Oil field wastes	18 ppm	Yields of harvestable fisheries products less in every case in the 1 creek receiving oil field wastes than in 5 nearby relatively undisturbed creeks: 4 to 30 times fewer shrimp, 2 to 25 times fewer blue crabs, 5 to 16 times fewer game fish, 1.5 to 11 times fewer forage fish; adverse effects may extend to the bay receiving the oil field waters; on average, half as many stations on State tracts yielded harvestable organisms in the bay receiving oil field wastes; study useful because it does incorporate reasonable controls; drawbacks in applying to other situations: the brine is at least as toxic as the soil, control bay is not so variable in salinity, and rate of dilution in the receiving bay is undetermined.

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Appendix XX.—Outer Continental Shelf Lands Act

(See Legislative History, p. 2177)

Chapter 345—Public Law 212

[H.R. 5134]

AN Act to provide for the jurisdiction of the United States over the submerged lands of the outer Continental Shelf, and to authorize the Secretary of the Interior to lease such lands for certain purposes

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That:

This Act may be cited as the "Outer Continental Shelf Lands Act".

Sec. 2. Definitions.—When used in this Act—

(a) The term "outer Continental Shelf" means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in section 2 of the Submerged Lands Act (Public Law 31, Eighty-third Congress, first session),[1] and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control;

(b) The term "Secretary" means the Secretary of the Interior;

(c) The term "mineral lease" means any form of authorization for the exploration for, or development or removal of deposits of, oil, gas, or other minerals; and

(d) The term "person" includes, in addition to a natural person, an association, a State, political subdivision of a State, or a private, public, or municipal corporation.

Sec. 3. Jurisdiction Over Outer Continental Shelf.—(a) It is hereby declared to be the policy of the United States that the subsoil and seabed of the outer Continental Shelf appertain to the United States and are subject to its jurisdiction, control, and power of disposition as provided in this Act.

(b) This Act shall be construed in such manner that the character as high seas of the waters above the outer Continental Shelf and the right to navigation and fishing therein shall not be affected.

Sec. 4. Laws Applicable to Outer Continental Shelf.—(a) (1) The Constitution and laws and civil and political jurisdiction of the United States are hereby extended to the subsoil and seabed of the outer Continental Shelf and to all artificial islands and fixed structures which may be erected thereon for the purpose of exploring for, developing, removing, and transporting resources therefrom, to the same extent as if the outer Continental Shelf were an area of exclusive Federal jurisdiction located within a State: Provided, however, That mineral leases on the outer Continental Shelf shall be maintained or issued only under the provisions of this Act.

(2) To the extent that they are applicable and not inconsistent with this Act or with other Federal laws and regulations of the Secretary now in effect or hereafter adopted, the civil and criminal laws of each adjacent State as of the effective date of this Act are hereby declared to be the law of the United States for that portion of the subsoil and seabed of the outer Continental Shelf, and artificial islands and fixed structures erected thereon, which would be within the area of the State if its boundaries were extended seaward to the outer margin of the outer Continental Shelf, and the President shall determine and publish in the Federal Register such projected lines extending seaward and defining each such area. All of such applicable laws shall be administered and enforced by the appropriate officer and courts of the United States. State taxation laws shall not apply to the outer Continental Shelf.

(3) The provisions of this section for adoption of State law as the law of the United States shall never be interpreted as a basis for claiming any interest in or jurisdiction on behalf of any State for any purpose over the seabed and subsoil of the outer Continental Shelf, or the property and natural resources thereof or the revenues therefrom.

(b) The United States district courts shall have original jurisdiction of cases and controversies arising out of or in connection with any operations conducted on the outer Continental Shelf for the purpose of exploring for, developing, removing or transporting by pipeline the natural resources, or involving rights to the natural resources of the subsoil and seabed of the outer Continental Shelf, and proceedings with respect to any such case or controversy may be instituted

[1] 43 U.S.C.A. § 1301.

in the judicial district in which any defendant resides or may be found, or in the judicial district of the adjacent State nearest the place where the cause of action arose.

(c) With respect to disability or death of an employee resulting from any injury occurring as the result of operations described in subjection (b), compensation shall be payable under the provisions of the Longshoremen's and Harbor Workers' Compensation Act.[3] For the purposes of the extension of the provisions of the Longshoremen's and Harbor Workers' Compensation Act under this section—

(1) the term "employee" does not include a master or member of a crew of any vessel, or an officer or employee of the United States or any agency thereof or of any State or foreign government, or of any political subdivision thereof;

(2) the term "employer" means an employer any of whose employees are employed in such operations; and

(3) the term "United States" when used in a geographical sense includes the outer Continental Shelf and artificial islands and fixed structures thereon.

(d) For the purposes of the National Labor Relations Act, as amended,[4] any unfair labor practice, as defined in such Act, occurring upon any artificial island or fixed structure referred to in subsection (a) shall be deemed to have occurred within the judicial district of the adjacent State nearest the place of location of such island or structure.

(e) (1) The head of the Department in which the Coast Guard is operating shall have authority to promulgate and enforce such reasonable regulations with respect to lights and other warning devices, safety equipment, and other matters relating to the promotion of safety of life and property on the islands and structures referred to in subsection (a) or on the waters adjacent thereto, as he may deem necessary.

(2) The head of the Department in which the Coast Guard is operating may mark for the protection of navigation any such island or structure whenever the owner has failed suitably to mark the same in accordance with regulations issued hereunder, and the owner shall pay the cost thereof. Any person, firm, company, or corporation who shall fail or refuse to obey any of the lawful rules and regulations issued hereunder shall be guilty of a misdemeanor and shall be fined not more than $100 for each offense. Each day during which such violation shall continue shall be considered a new offense.

(f) The authority of the Secretary of the Army to prevent obstruction to navigation in the navigable waters of the United States is hereby extended to artificial islands and fixed structures located on the outer Continental Shelf.

(g) The specific application by this section of certain provisions of law to the subsoil and seabed of the outer Continental Shelf and the artificial islands and fixed structures referred to in subsection (a) or to acts or offenses occurring or committed thereon shall not give rise to any inference that the application to such islands and structures, acts, or offenses of any other provision of law is not intended.

Sec. 5. Administration of Leasing of the Outer Continental Shelf.—(a) (1) The Secretary shall administer the provisions of this Act relating to the leasing of the outer Continental Shelf, and shall prescribe such rules and regulations as may be necessary to carry out such provisions. The Secretary may at any time prescribe and amend such rules and regulations as he determines to be necessary and proper in order to provide for the prevention of waste and conservation of the natural resources of the outer Continental Shelf, and the protection of correlative rights therein, and, notwithstanding any other provisions herein, such rules and regulations shall apply to all operations conducted under a lease issued or maintained under the provisions of this Act. In the enforcement of conservation laws, rules, and regulations the Secretary is authorized to cooperate with the conservation agencies of the adjacent States. Without limiting the generality of the foregoing provisions of this section, the rules and regulations prescribed by the Secretary thereunder may provide for the assignment or relinquishment of leases, for the sale of royalty oil and gas accruing or reserved to the United States at not less than market value, and, in the interest of conservation, for unitization, pooling, drilling agreements, suspensions of operations or production, reduction of rentals or royalties, compensatory royalty agreements,

[3] 33 U.S.C.A. §§ 901–950.
[4] 29 U.S.C.A. §§ 151–167.

subsurface storage of oil or gas in any of said submerged lands, and drilling or other easements necessary for operations or production.

(2) Any person who knowingly and willfully violates any rule or regulation prescribed by the Secretary for the prevention of waste, the conservation of the natural resources, or the protection of correlative rights shall be deemed guilty of a misdemeanor and punishable by a fine of not more than $2,000 or by imprisonment for not more than six months, or by both such fine and imprisonment, and each day of violation shall be deemed to be a separate offense. The issuance and continuance in effect of any lease, or of any extension, renewal, or replacement of any lease under the provisions of this Act shall be conditioned upon compliance with the regulations issued under this Act and in force and effect on the date of the issuance of the lease if the lease is issued under the provisions of section 8 hereof, or with the regulations issued under the provisions of section 6(b), clause (2), hereof if the lease is maintained under the provisions of section 6 hereof.

(b) (1) Whenever the owner of a nonproducing lease fails to comply with any of the provisions of this Act, or of the lease, or of the regulations issued under this Act and in force and effect on the date of the issuance of the lease if the lease is issued under the provisions of section 8 hereof, or of the regulations issued under the provisions of section 6(b), clause (2), hereof, if the lease is maintained under the provisions of section 6 hereof, such lease may be canceled by the Secretary, subject to the right of judicial review as provided in section 8(j), if such default continues for the period of thirty days after mailing of notice by registered letter to the lease owner at his record post office address.

(2) Whenever the owner of any producing lease fails to comply with any of the provisions of this Act, or of the lease, or of the regulations issued under this Act and in force and effect on the date of the issuance of the lease if the lease is issued under the provisions of section 8 hereof, or of the regulations issued under the provisions of section 6(b), clause (2), hereof, if the lease is maintained under the provisions of section 6 hereof, such lease may be forfeited and canceled by an appropriate proceeding in any United States district court having jurisdiction under the provisions of section 4(b) of this Act.

(c) Rights-of-way through the submerged lands of the outer Continental Shelf, whether or not such lands are included in a lease maintained or issued pursuant to this Act, may be granted by the Secretary for pipeline purposes for the transportation of oil, natural gas, sulphur, or other mineral under such regulations and upon such conditions as to the application therefor and the survey, location and width thereof as may be prescribed by the Secretary, and upon the express condition that such oil or gas pipelines shall transport or purchase without discrimination, oil or natural gas produced from said submerged lands in the vicinity of the pipeline in such proportionate amounts as the Federal Power Commission, in the case of gas, and the Interstate Commerce Commission, in the case of oil, may, after a full hearing with due notice thereof to the interested parties, determine to be reasonable, taking into account, among other things, conservation and the prevention of waste. Failure to comply with the provisions of this section or the regulations and conditions prescribed thereunder shall be ground for forfeiture of the grant in an appropriate judicial proceeding instituted by the United States in any United States district court having jurisdiction under the provisions of section 4(b) of this Act.

Sec. 6. Maintenance of Leases on Outer Continental Shelf.—(a) The provisions of this section shall apply to any mineral lease covering submerged lands of the outer Continental Shelf issued by any State (including any extension, renewal, or replacement thereof heretofore granted pursuant to such lease or under the laws of such State) if—

(1) such lease, or a true copy thereof, is filed with the Secretary by the lessee or his duly authorized agent within ninety days from the effective date of this Act, or within such further period or periods as provided in section 7 hereof or as may be fixed from time to time by the Secretary;

(2) such lease was issued prior to December 21, 1948, and would have been on June 5, 1950, in force and effect in accordance with its terms and provisions and the law of the State issuing it had the State had authority to issue such lease:

(3) there is filed with the Secretary, within the period or periods specified in paragraph (1) of this subsection, (A) a certificate issued by the State official or agency having jurisdiction over such lease stating that it would have been in force and effect as required by the provisions of paragraph

(2) of this subsection, or (B) in the absence of such certificate, evidence in the form of affidavits, receipts, canceled checks, or other documents that may be required by the Secretary, sufficient to prove that such lease would have been so in force and effect;

(4) except as otherwise provided in section 7 hereof, all rents, royalties, and other sums payable under such lease between June 5, 1950, and the effective date of this Act, which have not been paid in accordance with the provisions thereof, or to the Secretary or to the Secretary of the Navy, are paid to the Secretary within the period or periods specified in paragraph (1) of this subsection, and all rents, royalties, and other sums payable under such lease after the effective date of this Act, are paid to the Secretary, who shall deposit such payments in the Treasury in accordance with section 9 of this Act;

(5) the holder of such lease certifies that such lease shall continue to be subject to the overriding royalty obligations existing on the effective date of this Act;

(6) such lease was not obtained by fraud or misrepresentation;

(7) such lease, if issued on or after June 23, 1947, was issued upon the basis of competitive bidding;

(8) such lease provides for a royalty to the lessor on oil and gas of not less than 12½ per centum and on sulphur of not less than 5 per centum in amount or value of the production saved, removed, or sold from the lease, or, in any case in which the lease provides for a lesser royalty, the holder thereof consents in writing, filed with the Secretary, to the increase of the royalty to the minimum herein specified;

(9) the holder thereof pays to the Secretary within the period or periods specified in paragraph (1) of this subsection an amount equivalent to any severance, gross production, or occupation taxes imposed by the State issuing the lease on the production from the lease, less the State's royalty interest in such production, between June 5, 1950, and the effective date of this Act and not heretofore paid to the State, and thereafter pays to the Secretary as an additional royalty on the production from the lease, less the United States' royalty interest in such production, a sum of money equal to the amount of the severance, gross production, or occupation taxes which would have been payable on such production to the State issuing the lease under its laws as they existed on the effective date of this Act;

(10) such lease will terminate within a period of not more than five years from the effective date of this Act in the absence of production or operations for drilling, or, in any case in which the lease provides for a longer period, the holder thereof consents in writing, filed with the Secretary, to the reduction of such period so that it will not exceed the maximum period herein specified; and

(11) the holder of such lease furnishes such surety bond, if any, as the Secretary may require and complies with such other reasonable requirements as the Secretary may deem necessary to protect the interests of the United States.

(b) Any person holding a mineral lease, which as determined by the Secretary, meets the requirements of subsection (a) of this section, may continue to maintain such lease, and may conduct operations thereunder, in accordance with (1) its provisions as to the area, the minerals covered, rentals and, subject to the provisions of paragraphs (8), (9) and (10) of subsection (a) of this section, as to royalties and as to the term thereof and of any extensions, renewals, or replacements authorized therein or heretofore authorized by the laws of the State issuing such lease, or, if oil or gas was not being produced in paying quantities from such lease on or before December 11, 1950, or if production in paying quantities has expired since December 11, 1950, then for a term from the effective date hereof equal to the term remaining unexpired on December 11, 1950, under the provisions of such lease or any extensions, renewals, or replacements authorized therein, or heretofore authorized by the laws of such State, and (2) such regulations as the Secretary may under section 5 of this Act prescribe within ninety days after making his determination that such lease meets the requirements of subsection (a) of this section: *Provided, however*, That any rights to sulphur under any lease maintained under the provisions of this subsection shall not extend beyond the primary term of such lease or any extension thereof under the provisions of such subsection (b) unless sulphur is being produced in paying quantities for drilling, well working, plant construction, or other operations for the production of sulphur, as approved by the Secretary, are being conducted on the area covered by such lease on the date of expiration of such primary term or extension: *Provided further*, That if sulphur is being produced in paying quantities on such date, then such rights shall continue to be maintained in accordance with such lease and the provisions of this Act: *Provided further*, That, if the primary term of a lease being maintained under subsection (b) hereof has expired prior to the effective date of this Act and oil or gas is being produced in paying quantities on such date, then such rights to sulphur as the lessee may have under such lease shall continue for twenty-four months from the effective date of this Act and as long thereafter as sulphur is produced in paying quantities, or drilling, well working, plant construction, or other operations for the production of sulphur, as approved by the Secretary, are being conducted on the area covered by the lease.

(c) The permission granted in subsection (b) of this section shall not be construed to be a waiver of such claims, if any, as the United States may have against the lessor or the lessee or any other person respecting sums payable or paid for or under the lease, or respecting activities conducted under the lease, prior to the effective date of this Act.

(d) Any person complaining of a negative determination by the Secretary of the Interior under this section may have such determination reviewed by the United States District Court for the District of Columbia by filing a petition for review within sixty days after receiving notice of such action by the Secretary.

(e) In the event any lease maintained under this section covers lands beneath navigable waters, as that term is used in the Submerged Lands Act, as well as lands of the outer Continental Shelf, the provisions of this section shall apply to such lease only insofar as it covers lands of the outer Continental Shelf.

Sec. 7. Controversy Over Jurisdiction.—In the event of a controversy between the United States and a State as to whether or not lands are subject to the provisions of this Act, the Secretary is authorized, notwithstanding the provisions of subsections (a) and (b) of section 6 of this Act, and with the concurrence of the Attorney General of the United States, to negotiate and enter into agreements with the State, its political subdivision or grantee or a lessee hereof, respecting operations under existing mineral leases and payment and impounding of rents, royalties, and other sums payable thereunder, or with the State, its political subdivision or grantee, respecting the issuance or nonissuance of new mineral leases pending the settlement of adjudication of the controversy. The authorization contained in the preceding sentence of this section shall not be construed to be a limitation upon the authority conferred on the Secretary in other sections of this Act. Payments made pursuant to such agreement, or pursuant to any stipulation between the United States and a State, shall be considered as compliance with section 6(a)(4) hereof. Upon the termination of such agreement or stipulation by reason of the final settlement or adjudication of such controversy, if the lands subject to any mineral lease are determined to be in whole or in part lands subject to the provisions of this Act, the lessee, if he has not already done so, shall comply with the requirements of section 6 (a), and thereupon the provisions of section 6 (b) shall govern such lease. The notice concerning "Oil and Gas Operations in the Submerged Coastal Lands of the Gulf of Mexico" issued by the Secretary on December 11, 1950 (15 F.R. 8835), as amended by the notice dated January 26, 1951 (16 F.R. 953), and as supplemented by the notices dated February 2, 1951 (16 F.R. 1203), March 5, 1951 (16 F.R. 2195), April 23, 1951 (16 F.R. 3623), June 25, 1951 (16 F.R. 6404), August 22, 1951 (16 F.R. 8720), October 24, 1951 (16 F.R. 10998), December 21, 1951 (17 F.R. 43), March 25, 1952 (17 F.R. 2821), June 26, 1952 (17 F.R. 5833), and December 24, 1952 (18 F.R. 48), respectively, is hereby approved and confirmed.

Sec. 8. Leasing of Outer Continental Shelf.—(a) In order to meet the urgent need for further exploration and development of the oil and gas deposits of the submerged lands of the outer Continental Shelf, the Secretary is authorized to grant to the highest responsible qualified bidder by competitive bidding under regulations promulgated in advance, oil and gas leases on submerged lands of the outer Continental Shelf which are not covered by leases meeting the requirements of subsection (a) of section 6 of this Act. The bidding shall be (1) by sealed bids, and (2) at the discretion of the Secretary, on the basis of a cash bonus with a royalty fixed by the Secretary at not less than 12½ per centum in amount or value of the production saved, removed or sold, or on the basis of royalty, but at not less than the per centum above mentioned, with a cash bonus fixed by the Secretary.

(b) An oil and gas lease issued by the Secretary pursuant to this section shall (1) cover a compact area not exceeding five thousand seven hundred and sixty acres, as the Secretary may determine, (2) be for a period of five years and as long thereafter as oil or gas may be produced from the area in paying quantities, or drilling or well reworking operations as approved by the Secretary are conducted thereon, (3) require the payment of a royalty of not less than 12½ per centum, in the amount or value of the production saved, removed, or sold from the lease, and (4) contain such rental provisions and such other terms and provisions as the Secretary may prescribe at the time of offering the area for lease.

(c) In order to meet the urgent need for further exploration and development of the sulphur deposits in the submerged lands of the outer Continental Shelf, the Secretary is authorized to grant to the qualified persons offering the highest cash bonuses on a basis of competitive bidding sulphur leases on submerged lands of the outer Continental Shelf, which are not covered by leases which include sulphur and meet the requirements of subsection (a) of section 6 of this Act, and which sulphur leases shall be offered for bid by sealed bids and granted on separate leases from oil and gas leases, and for a separate consideration, and without priority or preference accorded to oil and gas lessees on the same area.

(d) A sulphur lease issued by the Secretary pursuant to this section shall (1) cover an area of such size and dimensions as the Secretary may determine, (2) be for a period of not more than ten years and so long thereafter as sulphur may be produced from the area in paying quantities or drilling, well reworking, plant construction, or other operations for the production of sulphur, as approved by the Secretary, are conducted thereon, (3) require the payment to the United States of such royalty as may be specified in the lease but not less than 5 per centum of the gross production or value of the sulphur at the wellhead, and (4) contain such rental provisions and such other terms and provisions as the Secretary may by regulation prescribe at the time of offering the area for lease.

(e) The Secretary is authorized to grant to the qualified persons offering the highest cash bonuses on a basis of competitive bidding leases of any mineral other than oil, gas, and sulphur in any area of the outer Continental Shelf not then under lease for such mineral upon such royalty, rental, and other terms and conditions as the Secretary may prescribe at the time of offering the area for lease.

(f) Notice of sale of leases, and the terms of bidding, authorized by this section shall be published at least thirty days before the date of sale in accordance with rules and regulations promulgated by the Secretary.

(g) All moneys paid to the Secretary for or under leases granted pursuant to this section shall be deposited in the Treasury in accordance with section 9 of this Act.

(h) The issuance of any lease by the Secretary pursuant to this Act, or the making of any interim arrangements by the Secretary pursuant to section 7 of this Act shall not prejudice the ultimate settlement or adjudication of the question as to whether or not the area involved is in the outer Continental Shelf.

(i) The Secretary may cancel any lease obtained by fraud or misrepresentation.

(j) Any person complaining of a cancellation of a lease by the Secretary may have the Secretary's action reviewed in the United States District Court for the District of Columbia by filing a petition for review within sixty days after the Secretary takes such action.

Sec. 9. Disposition of Revenues.—All rentals, royalties, and other sums paid to the Secretary or the Secretary of the Navy under any lease on the outer Continental Shelf for the period from June 5, 1950, to date, and thereafter shall be deposited in the Treasury of the United States and credited to miscellaneous receipts.

Sec. 10. Refunds.—(a) Subject to the provisions of subsection (b) hereof, when it appears to the satisfaction of the Secretary that any person has made a payment to the United States in connection with any lease under this Act in excess of the amount he was lawfully required to pay, such excess shall be repaid without interest to such person or his legal representative, if a request for repayment of such excess is filed with the Secretary within two years after the making of the payment, or within ninety days after the effective date of this Act. The Secretary shall certify the amounts of all such repayments to the Secretary of the Treasury, who is authorized and directed to make such repayments out of any moneys in the special account established under section 9 of this Act and to issue his warrant in settlement thereof.

(b) No refund of or credit for such excess payment shall be made until after the expiration of thirty days from the date upon which a report giving the name of the person to whom the refund or credit is to be made, the amount of such refund or credit, and a summary of the facts upon which the determination of the Secretary was made is submitted to the President of the Senate and the Speaker of the House of Representatives for transmittal to the appropriate legislative committee of each body, respectively: *Provided*, That if the Congress shall not be in session on the date of such submission or shall adjourn prior to the expiration of thirty days from the date of such submission, then such payment or credit shall not be made until thirty days after the opening day of the next succeeding session of Congress.

Sec. 11. Geological and Geophysical Explorations.—Any agency of the United States and any person authorized by the Secretary may conduct geological and geophysical explorations in the outer Continental Shelf, which do not interfere with or endanger actual operations under any lease maintained or granted pursuant to this Act, and which are not unduly harmful to aquatic life in such area.

Sec. 12. Reservations.—(a) The President of the United States may, from time to time, withdraw from disposition any of the unleased lands of the outer Continental Shelf.

(b) In time of war, or when the President shall so prescribe, the United States shall have the right of first refusal to purchase at the market price all or any portion of any mineral produced from the outer Continental Shelf.

(c) All leases issued under this Act, and leases, the maintenance and operation of which are authorized under this Act, shall contain or be construed to contain a provision whereby authority is vested in the Secretary, upon a recommendation of the Secretary of Defense, during a state of war or national emergency declared by the Congress or the President of the United States after the effective date of this Act, to suspend operations under any lease; and all such leases shall contain or be construed to contain provisions for the payment of just compensation to the lessee whose operations are thus suspended.

(d) The United States reserves and retains the right to designate by and through the Secretary of Defense, with the approval of the President, as areas restricted from exploration and operation that part of the outer Continental Shelf needed for national defense; and so long as such designation remains in effect no exploration or operations may be conducted on any part of the surface of such area except with the concurrence of the Secretary of Defense; and if operations or production under any lease theretofore issued on lands within any such restricted area shall be suspended, any payment of rentals, minimum royalty, and royalty prescribed by such lease likewise shall be suspended during such period of suspension of operation and production, and the term of such lease shall be extended by adding thereto any such suspension period, and the United States shall be liable to the lessee for such compensation as is required to be paid under the Constitution of the United States.

(e) All uranium, thorium, and all other materials determined pursuant to paragraph (1) of subsection (b) of section 5 of the Atomic Energy Act of 1946, as amended,[4] to be peculiarly essential to the production of fissionable material, contained, in whatever concentration, in deposits in the subsoil or seabed of the outer Continental Shelf are hereby reserved for the use of the United States.

(f) The United States reserves and retains the ownership of and the right to extract all helium, under such rules and regulations as shall be prescribed by the Secretary, contained in gas produced from any portion of the outer Continental Shelf which may be subject to any lease maintained or granted pursuant to this Act, but the helium shall be extracted from such gas so as to cause no substantial delay in the delivery of gas produced to the purchaser of such gas.

Sec. 13. Naval Petroleum Reserve Executive Order Repealed.—Executive Order Numbered 10426, dated January 16, 1953,[5] entitled "Setting Aside Submerged Lands of the Continental Shelf as a Naval Petroleum Reserve", is hereby revoked.

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[4] 42 U.S.C.A. § 1805.
[5] 34 U.S.C.A. § 524 note.

Sec. 14. Prior Claims Not Affected.—Nothing herein contained shall affect such rights, if any, as may have been acquired under any law of the United States by any person in lands subject to this Act and such rights, if any, shall be governed by the law in effect at the time they may have been acquired: *Provided, however*, That nothing herein contained is intended or shall be construed as a finding, interpretation, or construction by the Congress that the law under which such rights may be claimed in fact applies to the lands subject to this Act or authorizes or compels the granting of such rights in such lands, and that the determination of the applicability or effect of such law shall be unaffected by anything herein contained.

Sec. 15. Report by Secretary.—As soon as practicable after the end of each fiscal year, the Secretary shall submit to the President of the Senate and the Speaker of the House of Representatives a report detailing the amounts of all moneys received and expended in connection with the administration of this Act during the preceding fiscal year.

Sec. 16. Appropriations.—There is hereby authorized to be appropriated such sums as may be necessary to carry out the provisions of this Act.

Sec. 17. Separability.—If any provision of this Act, or any section, subsection, sentence, clause, phrase or individual word, or the application thereof to any person or circumstance is held invalid, the validity of the remainder of the Act and of the application of any such provision, section, subsection, sentence, clause, phrase or individual word to other persons and circumstances shall not be affected thereby.

Approved August 7, 1953.

APPENDIX XXI. PUBLIC LAW 92-583

AN ACT To establish a national policy and develop a national program for the management, beneficial use, protection, and development of the land and water resources of the Nation's coastal zones, and for other purposes

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That the Act entitled "An Act to provide for a comprehensive, long-range, and coordinated national program in marine science, to establish a National Council on Marine Resources and Engineering Development, and a Commission on Marine Science, Engineering and Resources, and for other purposes", approved June 17, 1966 (80 Stat. 203), as amended (33 U.S.C. 1101–1124), is further amended by adding at the end thereof the following new title:

TITLE III—MANAGEMENT OF THE COASTAL ZONE

SHORT TITLE

Sec. 301. This title may be cited as the "Coastal Zone Management Act of 1972".

CONGRESSIONAL FINDINGS

Sec. 302. The Congress finds that—

(a) There is a national interest in the effective management, beneficial use, protection, and development of the coastal zone;

(b) The coastal zone is rich in a variety of natural, commercial, recreational, industrial, and esthetic resources of immediate and potential value to the present and future well-being of the Nation;

(c) The increasing and competing demands upon the lands and waters of our coastal zone occasioned by population growth and economic development, including requirements for industry, commerce, residential development, recreation, extraction of mineral resources and fossil fuels, transportation and navigation, waste disposal, and harvesting of fish, shellfish, and other living marine resources, have resulted in the loss of living marine resources, wildlife, nutrient-rich areas, permanent and adverse changes to ecological systems, decreasing open space for public use, and shoreline erosion;

(d) The coastal zone, and the fish, shellfish, other living marine resources, and wildlife therein, are ecologically fragile and consequently extremely vulnerable to destruction by man's alterations;

(e) Important ecological, cultural, historic, and esthetic values in the coastal zone which are essential to the well-being of all citizens are being irretrievably damaged or lost;

(f) Special natural and scenic characteristics are being damaged by ill-planned development that threatens these values;

(g) In light of competing demands and the urgent need to protect and to give high priority to natural systems in the coastal zone, present state and local institutional arrangements for planning and regulating land and water uses in such areas are inadequate; and

(h) The key to more effective protection and use of the land and water resources of the coastal zone is to encourage the states to exercise their full authority over the lands and waters in the coastal zone by assisting the states, in cooperation with Federal and local governments and other vitally affected interests, in developing land and water use programs for the coastal zone, including unified policies, criteria, standards, methods, and processes for dealing with land and water use decisions of more than local significance.

DECLARATION OF POLICY

SEC. 303. The Congress finds and declares that it is the national policy (a) to preserve, protect, develop, and where possible, to restore or enhance, the resources of the Nation's coastal zone for this and succeeding generations, (b) to encourage and assist the states to exercise effectively their responsibilities in the coastal zone through the development and implementation of management programs to achieve wise use of the land and water resources of the coastal zone giving full consideration to ecological, cultural, historic, and esthetic values as well as to needs for economic development, (c) for all Federal agencies engaged in programs affecting the coastal zone to cooperate and participate with state and local governments and regional agencies in effectuating the purposes of this title, and (d) to encourage the participation of the public, of Federal, state, and local governments and of regional agencies in the development of coastal zone management programs. With respect to implementation of such management programs, it is the national policy to encourage cooperation among the various state and regional agencies including establishment of interstate and regional agreements, cooperative procedures, and joint action particularly regarding environmental problems.

DEFINITIONS

SEC. 304. For the purposes of this title—

(a) "Coastal zone" means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal states, and includes transitional and intertidal areas, salt marshes, wetlands, and beaches. The zone extends, in Great Lakes waters, to the international boundary between the United States and Canada and, in other areas, seaward to the outer limit of the United States territorial sea. The zone extends inland from the shorelines only to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters. Excluded from the coastal zone are lands the use of which is by law subject solely to the discretion of or which is held in trust by the Federal Government, its officers or agents.

(b) "Coastal waters" means (1) in the Great Lakes area, the waters within the territorial jurisdiction of the United States consisting of the Great Lakes, their connecting waters, harbors, roadsteads, and estuary-type areas such as bays, shallows, and marshes and (2) in other areas, those waters, adjacent to the shoreline, which contain a measurable quantity or percentage of sea water, including, but not limited to, sounds, bays, lagoons, bayous, ponds, and estuaries.

(c) "Coastal state" means a state of the United States in, or bordering on, the Atlantic, Pacific, or Arctic Ocean, the Gulf of Mexico, Long Island Sound, or one or more of the Great Lakes. For the purposes of this title, the term also includes Puerto Rico, the Virgin Islands, Guam, and American Samoa.

(d) "Estuary" means that part of a river or stream or other body of water having unimpaired connection with the open sea, where the sea water is measurably diluted with fresh water derived from land drainage. The term includes estuary-type areas of the Great Lakes.

(e) "Estuarine sanctuary" means a research area which may include any part or all of an estuary, adjoining transitional areas, and adjcent uplands, constituting to the extent feasible a natural unit, set aside to provide scientists and students the opportunity to examine over a period of time the ecological relationships within the area.

(f) "Secretary" means the Secretary of Commerce.

(g) "Management program" includes, but is not limited to, a comprehensive statement in words, maps, illustrations, or other media of communication, prepared and adopted by the state in accordance with the provisions of this title, setting forth objectives, policies, and standards to guide public and private uses of lands and waters in the coastal zone.

(h) "Water use" means activities which are conducted in or on the water; but does not mean or include the establishment of any water quality standard or criteria or the regulation of the discharge or runoff of water pollutants except the standards, criteria, or regulations which are incorporated in any program as required by the provisions of section 307(f).

(i) "Land use" means activities which are conducted in or on the shorelands within the coastal zone, subject to the requirements outlined in section 307(g).

MANAGEMENT PROGRAM DEVELOPMENT GRANTS

SEC. 305. (a) The Secretary is authorized to make annual grants to any coastal state for the purpose of assisting in the development of a management program for the land and water resources of its coastal zone.

(b) Such management program shall include:

(1) an identification of the boundaries of the coastal zone subject to the management program;

(2) a definition of what shall constitute permissible land and water uses within the coastal zone which have a direct and significant impact on the coastal waters;

(3) an inventory and designation of areas of particular concern within the coastal zone;

(4) an identification of the means by which the state proposes to exert control over the land and water uses referred to in paragraph (2) of this subsection, including a listing of relevant constitutional provisions, legislative enactments, regulations, and judicial decisions;

(5) broad guidelines on priority of uses in particular areas, including specifically those uses of lowest priority;

(6) a description of the organizational structure proposed to implement the management program, including the responsibilities and interrelationships of local, areawide, state, regional, and interstate agencies in the management process.

(c) The grants shall not exceed 66⅔ per centum of the costs of the program in any one year and no state shall be eligible to receive more than three annual grants pursuant to this section. Federal funds received from other sources shall not be used to match such grants. In order to qualify for grants under this section, the state must reasonably demonstrate to the satisfaction of the Secretary that such grants will be used to develop a management program consistent with the requirements set forth in section 306 of this title. After making the initial grant to a coastal state, no subsequent grant shall be made under this section unless the Secretary finds that the state is satisfactorily developing such management program.

(d) Upon completion of the development of the state's management program, the state shall submit such program to the Secretary for review and approval pursuant to the provisions of section 306 of this title, or such other action as he deems necessary. On final approval of such program by the Secretary, the state's eligibility for further grants under this section shall terminate, and the state shall be eligible for grants under section 306 of this title.

(e) Grants under this section shall be allocated to the states based on rules and regulations promulgated by the Secretary: *Provided, however*, That no management program development grant under this section shall be made in excess of 10 per centum nor less than 1 per centum of the total amount appropriated to carry out the purposes of this section.

(f) Grants or portions thereof not obligated by a state during the fiscal year for which they were first authorized to be obligated by the state, or during the fiscal year immediately following, shall revert to the Secretary, and shall be added by him to the funds available for grants under this section.

(g) With approval of the Secretary, the state may allocate to a local government, to an areawide agency designated under section 204 of the Demonstration Cities and Metropolitan Development Act of 1966, to a regional agency, or to an interstate agency, a portion of the grant under this section, for the purpose of carrying out the provisions of this section.

(h) The authority to make grants under this section shall expire on June 30, 1977.

ADMINISTRATIVE GRANTS

SEC. 306. (a) The Secretary is authorized to make annual grants to any coastal state for not more than 66⅔ per centum of the costs of administering the state's management program, if he approves such program in accordance with subsection (c) hereof. Federal funds received from other sources shall not be used to pay the state's share of costs.

(b) Such grants shall be allocated to the states with approved programs based on rules and regulations promulgated by the Secretary which shall take into account the extent and nature of the shoreline and area covered by the plan, population of the area, and other relevant factors: *Provided, however,* That no annual administrative grant under this section shall be made in excess to 10 per centum nor less than 1 per centum of the total amount appropriated to carry out the purposes of this section.

(c) Prior to granting approval of a management program submitted by a coastal state, the Secretary shall find that:

(1) The state has developed and adopted a management program for its coastal zone in accordance with rules and regulations promulgated by the Secretary, after notice, and with the opportunity of full participation by relevant Federal agencies, state agencies, local governments, regional organizations, port authorities, and other interested parties, public and private, which is adequate to carry out the purposes of this title and is consistent with the policy declared in section 303 of this title.

(2) The state has:

(A) coordinated its program with local, areawide, and interstate plans applicable to areas within the coastal zone existing on January 1 of the year in which the state's management program is submitted to the Secretary, which plans have been developed by a local government, an areawide agency designated pursuant to regulations established under section 204 of the Demonstration Cities and Metropolitan Development Act of 1966, a regional agency, or an interstate agency; and

(B) established an effective mechanism for continuing consultation and coordination between the management agency designated pursuant to paragraph (5) of this subsection and with local governments, interstate agencies, regional agencies, and areawide agencies within the coastal zone to assure the full participation of such local governments and agencies in carrying out the purposes of this title.

(3) The state has held public hearings in the development of the management program.

(4) The management program and any changes thereto have been reviewed and approved by the Governor.

(5) The Governor of the state has designated a single agency to receive and administer the grants for implementing the management program required under paragraph (1) of this subsection.

(6) The state is organized to implement the management program required under paragraph (1) of this subsection.

(7) The state has the authorities necessary to implement the program, including the authority required under subsection (d) of this section.

(8) The management program provides for adequate consideration of the national interest involved in the siting of facilities necessary to meet requirements which are other than local in nature.

(9) The management program makes provision for procedures whereby specific areas may be designated for the purpose of preserving or restoring them for their conservation, recreational, ecological, or esthetic values.

(d) Prior to granting approval of the management program, the Secretary shall find that the state, acting through its chosen agency or agencies, including local governments, areawide agencies designated under section 204 of the Demonstration Cities and Metropolitan Development Act of 1966, regional agencies, or interestate agencies, has authority for the management of the coastal zone in accordance with the management program. Such authority shall include power—

(1) to administer land and water use regulations, control development in order to ensure compliance with the management program, and to resolve conflicts among competing uses; and

(2) to acquire fee simple and less than fee simple interests in lands, waters, and other property through condemnation or other means when necessary to achieve conformance with the management program.

(e) Prior to granting approval, the Secretary shall also find that the program provides:

(1) for any one or a combination of the following general techniques for control of land and water uses within the coastal zone;

(A) State establishment of criteria and standards for local implementation, subject to administrative review and enforcement of compliance;

(B) Direct state land and water use planning and regulation; or

(C) State administrative review for consistency with the management program of all development plans, projects, or land and water use regulations, including exceptions and variances thereto, proposed by any state or local authority or private developer, with power to approve or disapprove after public notice and an opportunity for hearings.

(2) for a method of assuring that local land and water use regulations within the coastal zone do not unreasonably restrict or exclude land and water uses of regional benefit.

(f) With the approval of the Secretary, a state may allocate to a local government, an areawide agency designated under section 204 of the Demonstration Cities and Metropolitan Development Act of 1966, a regional agency, or an interstate agency, a portion of the grant under this section for the purpose of carrying out the provisions of this section: *Provided*, That such allocation shall not relieve the state of the responsibility for ensuring that any funds so allocated are applied in furtherance of such state's approved management program.

(g) The state shall be authorized to amend the management program. The modification shall be in accordance with the procedures required under subsection (c) of this section. Any amendment or modification of the program must be approved by the Secretary before additional administrative grants are made to the state under the program as amended.

(h) At the discretion of the state and with the approval of the Secretary, a management program may be developed and adopted in segments so that immediate attention may be devoted to those areas within the coastal zone which most urgently need management programs: *Provided*, That the state adequately provides for the ultimate coordination of the various segments of the management program into a single unified program and that the unified program will be completed as soon as is reasonably practicable.

INTERAGENCY COORDINATION AND COOPERATION

SEC. 307. (a) In carrying out his functions and responsibilities under this title, the Secretary shall consult with, cooperate with, and, to the maximum extent practicable, coordinate his activities with other interested Federal agencies.

(b) The Secretary shall not approve the management program submitted by a state pursuant to section 306 unless the views of Federal agencies principally affected by such program have been adequately considered. In case of serious disagreement between any Federal agency and the state in the development of the program the Secretary, in cooperation with the Executive Office of the President, shall seek to mediate the differences.

(c)(1) Each Federal agency conducting or supporting activities directly affecting the coastal zone shall conduct or support those activities in a manner which is, to the maximum extent practicable, consistent with approved state management programs.

(2) Any Federal agency shall undertake any development project in the coastal zone of a state shall insure that the project is, to the maximum extent practicable, consistent with approved state management programs.

(3) After final approval by the Secretary of a state's management program, any applicant for a required Federal license or permit to conduct an activity affecting land or water uses in the coastal zone of that state shall provide in the application to the licensing or permitting agency a certification that the proposed activity complies with the state's approved program and that such activity will be

conducted in a manner consistent with the program. At the same time, the applicant shall furnish to the state or its designated agency a copy of the certification, with all necessary information and data. Each coastal state shall establish procedures for public notice in the case of all such certifications and, to the extent it deems appropriate, procedures for public hearings in connection therewith. At the earliest practicable time, the state or its designated agency shall notify the Federal agency concerned that the state concurs with or objects to the applicant's certification. If the state or its designated agency fails to furnish the required notification within six months after receipt of its copy of the applicant's certification, the state's concurrence with the certification shall be conclusively presumed. No license or permit shall be granted by the Federal agency until the state or its designated agency has concurred with the applicant's certification or until, by the state's failure to act, the concurrence is conclusively presumed, unless the Secretary on his own initiative or upon appeal by the applicant, finds after providing a reasonable opportunity for detailed comments from the Federal agency involved and from the state, that the activity is consistent with the objectives of this title or is otherwise necessary in the interest of national security.

(d) State and local governments submitting applications for Federal assistance under other Federal programs affecting the coastal zone shall indicate the views of the appropriate state or local agency as to the relationship of such activities to the approved management program for the coastal zone. Such applications shall be submitted and coordinated in accordance with the provisions of title IV of the Intergovernmental Coordination Act of 1968 (82 Stat. 1098). Federal agencies shall not approve proposed projects that are inconsistent with a constla state's management program, except upon a finding by the Secretary that such project is consistent with the purposes of this title or necessary in the interest of national security.

(1) to diminish either Federal or state jurisdiction, responsibility, or rights in the field of planning, development, or control of water resources, submerged lands, or navigable waters; nor to displace, supersede, limit, or modify any interstate compact or the jurisdiction or responsibility of any legally established joint or common agency of two or more states or of two or more states and the Federal Government; nor to limit the authority of Congress to authorize and fund projects;

(2) as superseding, modifying, or repealing existing laws applicable to the various Federal agencies; nor to affect the jurisdiction, powers, or prerogatives of the International Joint Commission, United States and Canada, the Permanent Engineering Board, and the United States operating entity or entities established pursuant to the Columbia River Basin Treaty, signed at Washington, January 17, 1961, or the International Boundary and Water Commission, United States and Mexico.

(f) Notwithstanding any other provision of this title, nothing in this title shall in any way affect any requirement (1) established by the Federal Water Pollution Control Act, as amended, or the Clean Air Act, as amended, or (2) established by the Federal Government or by any state or local government pursuant to such Acts. Such requirements shall be incorporated in any program developed pursuant to this title and shall be the water pollution control and air pollution control requirements applicable to such program.

(g) When any state's coastal zone management program, submitted for approval or proposed for modification pursuant to section 306 of this title, includes requirements as to shorelands which also would be subject to any Federally supported national land use program which may be hereafter enacted, the Secretary, prior to approving such program, shall obtain the concurrence of the Secretary of the Interior, or such other Federal official as may be designated to administer the national land use program, with respect to that portion of the coastal zone management program affecting such inland areas.

PUBLIC HEARINGS

SEC. 308. All public hearings required under this title must be announced at least thirty days prior to the hearing date. At the time of the announcement, all agency materials pertinent to the hearings, including documents, studies, and other data, must be made available to the public for review and study. As similar materials are subsequently developed, they shall be made available to the public as they become available to the agency.

REVIEW OF PERFORMANCE

SEC. 309. (a) The Secretary shall conduct a continuing review of the management programs of the coastal states and of the performance of each state.

(b) The Secretary shall have the authority to terminate any financial assistance extended under section 306 and to withdraw any unexpended portion of such assistance if (1) he determines that the state is failing to adhere to and is not justified in deviating from the program approved by the Secretary; and (2) the state has been given notice of the proposed termination and withdrawal and given an opportunity to present evidence of adherence or justification for altering its program.

RECORDS

SEC. 310. (a) Each recipient of a grant under this title shall keep such records as the Secretary shall prescribe, including records which fully disclose the amount and disposition of the funds received under the grant, the total cost of the project or undertaking supplied by other sources, and such other records as will facilitate an effective audit.

(b) The Secretary and the Comptroller General of the United States, or any of their duly authorized representatives, shall have access for the purpose of audit and examination to any books, documents, papers, and records of the recipient of the grant that are pertinent to the determination that funds granted are used in accordance with this title.

ADVISORY COMMITTEE

SEC. 311. (a) The Secretary is authorized and directed to establish a Coastal Zone Management Advisory Committee to advise, consult with, and make recommendations to the Secretary on matters of policy concerning the coastal zone. Such committee shall be composed of not more than fifteen persons designated by the Secretary and shall perform such functions and operate in such a manner as the Secretary may direct. The Secretary shall insure that the committee membership as a group possesses a broad range of experience and knowledge relating to problems involving management, use, conservation, protection, and development of coastal zone resources.

(b) Members of the committee who are not regular full-time employees of the United States, while serving on the business of the committee, including traveltime, may receive compensation at rates not exceeding $100 per diem; and while so serving away from their homes or regular places of business may be allowed travel expenses, including per diem in lieu of subsistence, as authorized by section 5703 of title 5, United States Code, for individuals in the Government service employed intermittently.

ESTUARINE SANCTUARIES

SEC. 312. The Secretary, in accordance with rules and regulations promulgated by him, is authorized to make available to a coastal state grants of up to 50 per centum of the costs of acquisition, development, and operation of estuarine sanctuaries for the purpose of creating natural field laboratories to gather data and make studies of the natural and human processes occurring within the estuaries of the coastal zone. The Federal share of the cost for each such sanctuary shall not exceed $2,000,000. No Federal funds received pursuant to section 305 or section 306 shall be used for the purpose of this section.

ANNUAL REPORT

SEC. 313. (a) The Secretary shall prepare and submit to the President for transmittal to the Congress not later than November 1 of each year a report on the administration of this title for the preceding fiscal year. The report shall include but not be restricted to (1) an identification of the state programs approved pursuant to this title during the preceding Federal fiscal year and a description of those programs; (2) a listing of the states participating in the provisions of this title and a description of the status of each state's programs and its accomplishments during the preceding Federal fiscal year; (3) an itemization of the allocation of funds to the various coastal states and a breakdown of the major projects and areas on which these funds were expended; (4) an identification of any state programs which have been reviewed and disapproved or with respect to which grants have been terminated under this title, and a statement of the reasons for such action; (5) a listing of all activities and projects which, pursuant to the provisions of subsection (c) or subsection (d) of section 307, are not consistent with an applicable approved state management program; (6) a summary of the regulations issued by the Secretary or in effect during the preceding Federal fiscal year; (7) a summary of a coordinated national strategy and program for the Nation's coastal zone including identification and discussion of Federal, regional, state, and local responsibilities and functions therein; (8) a summary of outstanding problems arising in the administration of this title in order of priority; and (9) such other information as may be appropriate.

(b) The report required by subsection (a) shall contain such recommendations for additional legislation as the Secretary deems necessary to achieve the objectives of this title and enhance its effective operation.

RULES AND REGULATIONS

SEC. 314. The Secretary shall develop and promulgate, pursuant to section 553 of title 5, United States Code, after notice and opportunity for full participation by relevant Federal agencies, state agencies, local governments, regional organizations, port authorities, and other interested parties, both public and private, such rules and regulations as may be necessary to carry out the provisions of this title.

AUTHORIZATION OF APPROPRIATIONS

SEC. 315. (a) There are authorized to be appropriated—

(1) the sum of $9,000,000 for the fiscal year ending June 30, 1973, and for each of the fiscal years 1974 through 1977 for grants under section 305, to remain available until expended;

(2) such sums, not to exceed $30,000,000, for the fiscal year ending June 30, 1974, and for each of the fiscal years 1975 through 1977, as may be necessary, for grants under section 306 to remain available until expended; and

(3) such sums, not to exceed $6,000,000 for the fiscal year ending June 30, 1974, as may be necessary, for grants under section 312, to remain available until expended.

(b) There are also authorized to be appropriated such sums, not to exceed $3,000,000, for fiscal year 1973 and for each of the four succeeding fiscal years, as may be necessary for administrative expenses incident to the administration of this title.

[Approved October 27, 1972.]

APPENDIX XXII. ESTIMATE OF THE COSTS OF THE SANTA BARBARA OIL SPILL OF 1969 BY PROFESSORS WALTER J. MEAD OF THE UNIVERSITY OF CALIFORNIA, SANTA BARBARA, AND PHILIP E. SORENSON OF FLORIDA STATE UNIVERSITY[1]

Dr. Walter J. Mead, University of California-Santa Barbara, and Dr. Philip E. Sorenson, Florida State University, (Platform A: The Oil Spill that Spread Around the World, pp. 36–40), have estimated the economic costs of the 1969 oil spill. Their estimates and comments follow:

Beach cleanup by operator	$4,887,000
Oil well control efforts by operator	3,600,000
Oil collection efforts by operator	2,000,000
Subtotal	10,487,000
All Federal agencies	382,000
State of California[1]	200,000
County of Santa Barbara	57,200
City of Santa Barbara[2]	([11])
Damage to tourism[3]	([11])
Damage to commercial fishing industry[4]	804,250

[1] Source: United States Department of the Interior, Geological Survey, Draft Environmental Statement, Volume III "Oil and Gas Development in the Santa Barbara Channel Outer Continental Shelf off California." Washington, D.C. 1975. pp. 183–185.

Property value loss [5]	1,197,000
Fish life damage	([11])
Bird life damage [6]	7,400
Seal and sea lion damage [7]	([11])
Intertidal plant and animal damage: [8]	
Low estimate	1,000
High estimate	25,000
Value of lost oil [9]	130,000
Recreational value lost [10]	3,150,000
Low estimate	16,415,850
High estimate	16,439,850

[1] Mainly Department of Fish and Game expenses.

[2] No direct cost of any significance. Some minor surveillance by City officials.

[3] The community firmly believed that the spill had a pronounced effect on tourism but the study indicates the contrary. There was some diversion from motels and restaurants near the ocean to other nearby areas and some diversion from the Santa Barbara area to other recreation areas in southern California but the net effect was negligible.

[4] Although biological studies indicate no serious effects on the fish there is a social cost involved since no fishing boats operated for a period of about two months because the harbor was blocked by a boom part of the time and gear was fouled by oil for the remainder. The loss shown is for a reduction in value of the 1969 fish catch together with uncompensated damage to the commercial fishing fleet.

[5] Some beach front real estate was damaged by the spill and there was a small decline in property values but the authors consider the decline temporary and that it will dissipate within five years if no further oil pollution occurs. The loss shown is for decreased rentals. However, a class action suit has recovered $4,500,000 damages for beach front property owners and boat owners.

[6] The authors state: "Bird losses during the period when the oil spill was most serious were 'relatively moderate' according to the U.S. Bureau of Sports Fisheries and Wildlife. The California Department of Fish and Game estimated that, by March 31, 1969, bird losses amounted to 3,600, not counting birds that perished in the open water and failed to drift ashore. By May 31, 1969, known bird deaths had increased to 3,686. Due to fortuitous circumstances, the bird population was uncommonly low while the oil spill was at its worst. In the absence of any large-scale bird loss we cannot assess a significant economic charge for bird damage. We will assume that the unknown bird losses equalled in number the known bird deaths. We know of no objective means by which the economic cost of bird losses may be assessed. We believe that this unknown value is greater than zero, hence to assert a value of zero would be to insert an avoidable error in our cost estimate. Accordingly we have arbitrarily assumed that each bird loss involved a social cost of one dollar. Thus the total cost for bird damage is $7,400." The authors further state that "even if a cost of ten dollars per bird is assumed, the bird damage is not a significant element in the total cost." However, some bird lovers would decline an estimate of value of a one dollar, or even a ten dollar, cost per bird. It is not unreasonable to assume that an avid ornithologist would place a value of $1,000 per bird, in which case this would become a significant element in the total social cost.

[7] A controversial article in Life magazine (Snell, 1969), which was accepted at face value by conservationists, indicated severe oil damage to the pinneped population of San Miguel Island, but biological studies (U.S. Department of the Interior, 1969; and Allen, 1969) do not confirm this.

[8] The authors admit that "it is impossible to assign a social cost representing damage to plant and animal life in the intertidal zone of the oil spill. On the other hand we can assert with some confidence that the cost is greater than zero . . . we have no means by which a reasonable cost estimate can be made." Therefore, they used the arbitrary values of $1,000 and $25,000.

[9] Since the oil from the blowout was denied to society, the value of this oil must be taken into account. The authors accept Allen's estimate that the amount of oil spilled in the first four months was about 80,000 barrels (Allen, 1969). They calculate the "marginal social value of the oil at $2.15 per barrel rather than the 1969 market price of $3.25 per barrel" since they claim the latter is artificially high due to oil import quotas. After deducting lifting and transportation costs that the oil would have incurred if it had been used the net social cost of the lost oil is given as $130,000.

[10] The cost of recreation lost was derived from a detailed survey in which residents were asked to compare the enjoyment they received from a beach visit to the enjoyment they received from going to a movie. A typical beach visit was established to be 1.74 times as enjoyable as a typical movie. In the twelve months following the spill it was estimated that there were 744,000 fewer visits to the beaches because of oil pollution.

[11] "Negligible.

Not all of the costs estimated by Mead and Sorenson were losses to society. The public received at least some side benefits from the expenditure of nearly $5 million for beach clean-up, during which debris from preceding floods was also removed. Payment for the use of resources that otherwise would be idle during clean-up is in some measure a benefit to society.

Appendix XXIII. Petroleum Development in the California Coastal Zone

(California Coastal Zone Conservation Commissions, Preliminary Coastal Plan, San Francisco, March 6, 1975, pp. 210–223)

PETROLEUM DEVELOPMENT

Findings

California Has Potentially Recoverable Petroleum Resources.—California has three general areas of petroleum production: onshore, State waters offshore, and Federal waters offshore. Estimates as to how much recoverable oil remains in these areas vary greatly, and depend on assumptions as to: (1) the size of known reservoirs and reservoirs thought to exist because of favorable conditions but not yet verified; and (2) the percentage of the oil in California reservoirs that might ultimately be recovered (average recovery efficiency). Using reservoir data from publications of the California Resources Agency and the National Petroleum Council, and assuming that California's historical average recovery efficiency of about 25 per cent prevails, the following figures describe California's estimated potentially recoverable petroleum resources—proven reserves plus 25 percent of the petroleum thought to exist based on geologic data, but not yet discovered: Onshore, 10.0 billion barrels; offshore, 12.8 billion barrels; total California, 22.8 billion barrels.

Using the same reservoir data, but assuming that increased oil prices and improved recovery technologies might result in an improved average recovery efficiency of up to 35 percent, as some experts believe possible for California, the following figures describe the estimated potentially recoverable petroleum resources: Onshore, 19.8 billion barrels; offshore, 18.6 billion barrels; total California, 37.4 billion barrels:. [E–f72]

Offshore Areas Are Future Locations of Oil and Gas Production.—California's onshore petroleum resources are still very substantial, though the largest reservoirs have probably been discovered and substantially developed already, and most of the remaining undiscovered onshore resource may lie in smaller pools and at greater depths than the reservoirs that historically have accounted for much of California's oil production. Increased onshore production will depend on improved secondary and tertiary recovery techniques, and on rising oil prices that encourage increased exploration, deeper drilling, and secondary and tertiary recovery from discovered reservoirs. The offshore resources now offer the least expensive option for rapid production of large volumes of oil in California. Much of the California offshore resource is close to the shoreline, and therefore production facilities may be highly visible from the coast. Most of the oil offshore of California is believed to lie beneath Federal submerged lands beyond California's jurisdiction, as much as 65 percent of it as water depths of 1,500 feet or more. The extent and cost of developing the Federal offshore resource will not be completely known until exploratory drilling occurs. /E–f73[

Current Offshore Production Comes from States Leased Areas.—Most present California offshore production comes from leases in the Santa Barbara Channel and offshore Wilmington and Huntington Beach reservoirs. According to 1971 data, there are over 1,800 actual producing wells on State-owned submerged lands between Point Conception and Huntington Beach. The State receives lease payments and royalties from any petroleum production on its submerged lands, which are managed by the State Lands Commission. The vast majority of the State's submerged lands have been made State petroleum resource sanctuaries in which no petroleum recovery activities are allowed. Laws creating additional petroleum sanctuaries have been proposed in the California Legislature and the U.S. Congress. Coastal cities (e.g., Long Beach) also hold several leases and receive a portion of the petroleum revenues; the State Lands Division maintains operating authority on the leases. [E–f74]

Moratorium Placed on New Offshore Drilling in State Waters.—In 1969, following the blowout on a platform in Federal waters off Santa Barbara, the State Lands Commission placed a moratorium on new drilling offshore in State waters. In December 1973 the State Lands Commission voted to permit drilling of new wells from already-built platforms on existing leases, subject to approval on a lease-by-lease basis. In late 1974 the Lands Commission granted approvals to several oil companies for such drilling, but then reversed these decisions in early 1975 pending further evaluation. [E–f74]

Federal Lease-Sale of Southern California Areas Scheduled for July 1975.—The Department of the Interior has called for lease proposals from oil companies for petroleum drilling in huge areas of submerged lands offshore of Los Angeles County beyond the three-mile State jurisdiction, for lease proposals for large areas off central and northern California at a later date, and for increased drilling on existing Federal leases in the Santa Barbara Channel. It the Department of the Interior decides to proceed with its lease-sale of the southern California area, the sale will occur about July 1975. [E–f75]

New Proposals for Federal Government to Sponsor Exploration.—The Chairman of the State Lands Commission and some members of the California congressional delegation are presently proposing that the Federal government sponsor all exploratory drilling on the Outer Continental Shelf (OCS), either by contracting with private companies to perform the work, or by developing a capability to do such exploration. This proposal would permit the government full knowledge of the extent of the OCS resource and the value of specific OCS areas prior to any leasing to private companies for development. [new]

California Has No Control over Federal Offshore Drilling.—Although these Federal activities may affect California's ocean water quality, marine life, and scenic values, could possibly deplete oil reservoirs extending under adjacent State submerged lands, and may directly lead to significant onshore developments of refineries, tanker terminals, storage tanks, and pipelines requiring permits from the Coastal Commission, California has no direct control over the Federal plans at this time. [E–f75]

Deficiencies in Federal Offshore Regulation and Supervision Are Being Remedied.—In the past, Federal regulations governing drilling and production procedures on Federal submerged lands, including requirements for depth of casing for blow-out preventers and crew training and supervision, have been less stringent than California Division of Oil and Gas regulations governing operations on State submerged lands, where there have been no significant spills resulting from offshore oil and gas operations. Deficiencies in Federal regulations led directly to the well blow-out in Federal waters off Santa Barbara in 1969. Federal regulations, procedures, and regulatory staff are now being greatly upgraded. It is expected that when revision of Federal regulations for the Pacific Coast area are completed, they will be in substantial conformance with those of the State. [E–f76]

Petroleum Production Is Declining.—The leasing of lands, exploration, drilling, and production of petroleum is an expensive and risky process. Offshore exploration and production operations are generally much more expensive than onshore activities. Exploration for petroleum has generally decreased in California and nationwide, however, over the past 20 years. The success rate of finding and completing new petroleum fields has also steadily declined. Petroleum shortages, increased costs of extraction, and the need for technological research continually push the price of petroleum upward, which in turn should allow increased exploration and research toward technological advances. Over the first six months of 1974 exploratory and drilling activity have increased. [E–f80]

Regional Amplification.—South Coast: Production of petroleum in the Los Angeles basin peaked in 1969; the same is true for production in the coastal area of the Basin. Exploratory drilling has been at historically low levels in both the onshore and offshore portions of the coastal area. Oil production and development drilling are both likely to continue to decline, although the increases in crude oil prices since 1973 may reduce the production decline rate below the approximately 10 percent per year rate normally experienced by California oil wells. It is projected that the average rate of decline in California production shipped to Los Angeles/Long Beach area refineries will be four percent per year to 1985. [E–f80RA]

California Has a Low Recovery Rate.—The nationwide recovery efficiency of oil has steadily increased to approximately 31 percent. California's 25 percent recovery efficiency lags behind other major oil and gas producing regions due to: (1) generally high viscosity of much of California's oil, and the relatively low pressures affecting reservoir drive properties of associated natural gases and water; (2) complex geologic formations holding the petroleum, with many reservoir problems; and, to a lesser degree (3) lack of State regulation that might maximize ultimate recovery of oil and gas by regulating well completion and production practices. [E–f77]

California Has Less Stringent Regulation over Petroleum Development.—Completion and production practices in many oil-producing States, including Alaska, Louisiana, Texas, and Wyoming, are regulated by a State agency (the Canadian province of Alberta also regulates petroleum development). California's laws do not provide for actual regulation of completion and production practices by the Division of Oil and Gas, and the California petroleum industry is allowed very wide discretion in production rates and such practices as simultaneous production from many pools, and optional ratios of gas/oil production, which in turn can lead to low recovery efficiencies. Some other states also have requirements for public disclosure of exploratory data within some period of time after filing with the State regulatory agency, to increase geologic investigations, stimulate exploration, promote a more competitive industry, and increase oil production; and the Department of the Interior has proposed regulations for OCS lease purchasers that would require public disclosure of geological and geophysical data following the purchase, to be made public within six months. California has no such disclosure requirement. [E–f78]

Secondary and Tertiary Production Methods Will Improve Petroleum Recovery.—Secondary and tertiary production methods offer the promise of increased efficiency in recovering oil and gas. California has benefited from secondary recovery innovations and their applications. About 15 percent of California's present oil production comes from secondary recovery operations. In some reservoirs, very little primary production is possible, but secondary recovery may increase production after primary recovery by 10–50 per cent of the original oil in place, and terfiar recovery may offer the potential for a total recovery of 30–70 per cent. Substantial improvements in recovery efficiency, will require improved technology, greater capital investments, higher well maintenance costs, and a higher price for refined products. With a greatly increased effort at secondary and tertiary methods average recovery efficiency for California may ultimately go as high as 35–40 percent of original oil in place. [E–f79]

Existing Wells Will Provide Increased Production; Consolidation of Drilling Sites Is Desirable.—Increased primary, secondary, and tertiary production from existing wells will entail substantially fewer new developments and land use conflicts than exploration and drilling for virginal reservoirs, onshore or offshore. Unitization (development of a reservoir as a single unit) and consolidation concentrates activity within smaller areas than does separate development by several petroleum companies. Unitization is practicularly desirable offshore—economically, environmentally, and aesthetically. [E–f81]

Offshore Oil Structures Are Visually Prominent.—Offshore petroleum operations are usually conducted from manmade platforms above the water's surface. Exploratory drilling and some production drilling are primarily accomplished from mobile platforms, whereas most production of oil and gas is controlled from fixed platforms. It is very difficult to make the judgment that offshore oil drilling and production platform are intrinsically at variance with the objectives of the Coastal Act. There has been substantial objection by some segments of the public to their use, based primarily on aesthetic grounds and concern for navigational safety. Because of their size and the elevation of coastal lands, these platforms can be seen from the coast even when located at great distances (12–20 miles) from the shoreline; they are particularly prominent when located near the coast. The existing designs apparently have large margin for improvement. Some members of the public note with approval their beneficial effects on sport fishing. The deepest platform production in the world presently is in 420 feet. Exxon Company U.S.A. plans to construct and operate a fixed platform in 850 feet of water in the Santa Barbara Channel. [E–f82 and RA]

Platforms and Islands Offer Multiple Public Uses.—Offshore oil drilling facilities, whether located on artificial islands or platforms, can provide public uses other than that of extracting oil. Under certain safety and aesthetic conditions, additional functions could be provided. This would likely require some engineering adjustments within sound principles of industrial and marine safety on the platforms. Additional functions, which may be appropriate for some installations, are scientific and educational accommodations, such as a physical oceanography research and education lab; general public accommodations for the observation of drilling operations; government installations (Coast Guard, weather service); aquafarming and mariculture operations; and platform self-sustaining power equipment. [E–f82RA]

Subsea Completion and Submerged Production Systems Reduce Costs and Aesthetic Impacts.—As of mid-1974, approximately 40 individual wells in shallow water on State-lands in the Santa Barbara Channel area had been completed entirely underwater rather than from permanent platforms, by using "subsea completion systems." Such systems still require support facilities on permanent platforms or onshore, but permit reduction in the number of platforms required for the development of the offshore resource. More sophisticated "submerged production systems," which would permit clustering of numerous wells completed subsea around a single subsea center that would in turn pump the oil and gas to facilities on platforms or onshore, would still further reduce the need for platforms. This would reduce both the aesthetic impacts of offshore development and the great expense of constructing platforms in deep waters. Actual experience with subsea completions and submerged production systems in deep water is still extremely limited. The difficulties involved in servicing or repairing such systems mean increased environmental risk. Such facilities need to be tested extensively by industry under operational conditions, with full observation afforded to appropriate government agencies, before they are utilized in deep water offshore activities. [E-f83]

Offshore Drilling Is More Hazardous than Onshore.—Oil and gas leaks in offshore drilling or production are statistically rare, and steadily improving offshore drilling technology should still further reduce the incidence of occurrence. However, the draft programmatic Environmental Impact Statement prepared by the Bureau of Land Maagement for the nationwide accelerated Federal offshore leasing program noted that major spills associated with OCS development are inevitable. The California offshore environment is relatively mild compared to the environment in offshore drilling areas elsewhere in the world, such as the North Sea and the Gulf of Alaska, and therefore presents somewhat reduced environment risks. Nevertheless, even in California offshore drilling generally involves greater environmental hazards than onshore drilling for several reasons: (1) People are at a logistical disadvantage in working in the offshore environment, wheher on the surface or underwater. Response time to crisis is slower than onshore, and the ability to maintain equipment and receive supplies is constrained. (2) Offshore facilities are subjected to more danger, including storms, vessel collisions, seawater corrosion, low water temperature problems, water currents, seismic activity, and tsunami (seismic sea waves). Platforms can be designed and constructed to withstand known Pacific Coast phenomena. (3) Leaks of oil and gas are more quickly diffused, and more difficult to plug. [E-f84]

Basic Spill Cleanup Methods Help Minimize Environmental Damage.—If an oil spill should occur, the substances must be contained and recovered quickly to minimize environmental damage. Present containment methods utilize floating booms or pneumatic curtains which confine the oil. Recovery methods include absorbing materials (e.g., straw), suction devices, adhesive materials to remove the oil from seawater, and skimming mechanisms that remove oil from water. Oil may also be dispersed into the water column by the addition of chemicals, collected with gelling substances, forced to the sea floor by combining with sinking agents, or burned with combustion fluids. Use of sinking and burning agents are generally forbidden by the California Department of Fish and Game. [E-f85]

Spill Containment and Cleanup Methods Are Still Inadequate.—Since 1969 larger amounts of money have been spent on improving oil spill prevention and containment programs and for cleanup equipment. Although the technology for containment and recovery of offshore oil spills has improved since the Santa Barbara spill, no system is likely to be completely effective. Using presently available equipment, oil containment and recovery can be reasonably effective in calm waters; but moderate to stormy conditions (winds of 20 or more knots and wave heights over five feet) will seriously hinder deployment of equipment, and will spread the spill regardless of containment attempts. Such conditions will also act to disperse and degrade the spill. Most oil spill contingency plans, including the National Oil Spill Contingency Plan implemented under the guidance of the Coast Guard, and the State of California Oil Spill Contingency Plan, have been tested under simulated conditions but have not yet been proven under actual crisis situation. [E-f86] (For further findings on oil spills and spill liability, as well as Coastal Plan policy, see Marine Environment section.)

Oil Field Brines Can Be Disposed of by Reinjection into Oil Producing Zones.—Inadequately treated oil field brines released at sea are highly polluting. In many instances, these brines can practically be disposed of by reinjecting them under pressure into oil producing zones. In addition to protecting water quality and decreasing odors associated with oil production, this practice can frequently help increase oil recovery from already-developed reservoirs. The Water Quality Control Board presently issues discharge requirements and the Division of Oil and Gas regulates any reinjection of brines. [E–f90]

Offshore Production Will Encourage Onshore Development.—Offshore petroleum production may encourage greater industrialization in certain areas of the coastal zone, will increase water and land transportation, and will necessitate construction of oil and gas pipelines and storage facilities. Offshore production off California could reduce the need for additional tanker terminal capacity along the coast. [E–f89]

Policies

136. Need for Offshore Development Should Be Clearly Determined.—New offshore oil and gas development of State or Federal lands shall be permitted only after: (1) development of the Outer Continental Shelf (OCS) off California has been clearly identified as an integral and priority part of a comprehensive, balanced national energy conservation and development program that gives consideration to full-scale energy conservation programs and to short-term and long-term resources availability [E–p16b]; or (2) a comprehensive analysis has determined the need for California offshore production in light of the anticipated inflow to California and PAD V of oil and other forms of energy from all other sources, including onshore oil production, Alaska North Slope oil and gas production, production in other regions of Alaska, foreign oil and gas imports, and in view of California's projected capacities to refine and store the anticipated inflow of oil from sources other than new offshore productions [E–p16a]; and (3) the coastal agency determines that the impacts on onshore resources and possible impacts on the coastal zone marine resources as a result of OCS development are acceptable according to the standards set forth in the Coastal Plan. [E–p16c]

Regional Amplification.—Central Coast: The current prohibition of oil exploration and drilling in the State tidelands of the Central Coast Region should be retained unless overriding national need is demonstrated. [E–p16RA]

137. Require Full Evaluation of Offshore Drilling Proposals.—Applicants for drilling permits in State offshore lands shall be required to submit to the State Lands Commission, State Energy Commission, and coastal agency one-, five-, and ten-year plans for exploration, production, and all related onshore and offshore development (including platforms, submerged production systems, pipelines, separation and storage facilities, and refineries) that might follow if drilling is successful. To the extent not already provided in the required California Environmental Impact Report, such development plans shall include the economic, environmental, and aesthetic impact on the immediate area and the entire coastal zone offshore and onshore facilities and operations, including all transportation and distribution facilities, and all measures to mitigate any environmental hazards of onshore and offshore activities, including alternatives to the anticipated facilities, programs for containment and recovery of potential oil spills, and improvements in marine traffic lanes, navigational equipment, and traffic control. The adequacy of such measures shall be taken into account in approving or disapproving the application. Plans shall also include discussion of petroleum supply and demand as specified in Policy 136. [E–p17] All the facilities and accommodations required in the lease shall be completed on a predetermined schedule specified in the lease. [E–p21RA] Plans shall be recognized as being dependent upon the results of exploratory drilling and changing techniques, and, as such, flexible, but changes in which plans shall be justified by the applicant with full disclosure of supporting data. [E–p17]

138. Allow Offshore Drilling Only Where Safe.—Offshore drilling and production shall be permitted only where it can be demonstrated that: (1) the most advanced state-of-the-art drilling and production technology is utilized; (2) the geologic characteristics of the area have been adequately investigated and are consistent with safe drilling and production; and (3) the proposed well sites are the least environmentally hazardous and aesthetically disruptive sites feasible. [E–p18]

139. Consolidate Drilling, Production, and Processing Sites.—All petroleum-related development and operations shall be consolidated (i.e., drilling, production, separation facilities, and support sites shall be unitized—developed and operated by a single company or group of companies for the benefit of all interested companies—or shall be shared) to the maximum extent feasible, unless it can be shown that unitization or consolidation will not reduce the number of facilities, or significantly reduce the number of producing wells or support facilities required to produce the reservoir economically and with minimal environmental impacts. For offshore facilities, unitization negotiations shall be entered into by all operators holding State leases covering one producing structure, and unitization of a new offshore field shall be carried out before commercial production is initiated. The unitization or consolidation requirements shall apply to all types of offshore platforms, submerged production systems, pipelines, storage facilities, separation facilities, and equipment and rights-of-way for transporting petroleum to refineries, whenever technically and economically feasible, and where legally permissible. [E–p19]

140. Use Submerged Completion and Production Systems Where Feasible and Environmentally Safe.—Subsea completion of wells and submerged production systems shall be used where environmentally safe, as demonstrated through adequate testing of equipment, through adequate testing of equipment by industry, observed by the appropriate government agencies, and where technically and economically feasible. In those areas where oil platforms or islands would have a substantial adverse environmental effect, including degradation of aesthetic values, no offshore drilling should be permitted unless and until subsea completions or submerged production systems are demonstrated to be environmentally safe. [E–p20]

141. Platforms Preferred Over Islands; Minimize Impact of Platforms.—Where subsea drilling, completion, or production is found to be technically or economically infeasible, or environmentally unsafe, thereby making platforms or islands necessary to development of the resource; or where platforms are necessary to service subsea completions, or submerged production systems, the following policies shall apply. [E–p21]

(*a*) *Prefer Platforms.*—Platforms shall be preferred over islands wherever safety considerations permit.

(*b*) *Minimize Number of Platforms.*—The number of offshore platforms shall be minimized by using each platform to drill as many wells, and/or to serve as many subsea completion and production systems, as is technically and economically feasible, and environmentally safe.

(*c*) *Review Design of Facilities.*—The design and aesthetics of the platforms or islands shall be carefully reviewed by the coastal agency and by the immediately landward local governments, and shall be consistent with the general design criteria of the Coastal Plan.

(*d*) *Allow Recreation in Waters Off Platforms.*—The waters surrounding new platforms or islands shall be open to sport fishing, diving, and boating, consistent with boating safety rules and practices.

(*e*) *Consider Multi-Purpose Public Area.*—Prior to actual construction of an artificial island, if an island is determined to be needed, full consideration shall be given to installation of multi-purpose public interest uses, including but not limited to small-boat landing piers and amenity public recreation areas, scientific and educational facilities (e.g., marine biology, oceanography and meteorology research stations), public tours of drilling operations, Coast Guard or U.S. Weather Service station, or aquaculture operations, consistent with public safety and other policies of the Coastal Plan. If the State Lands Commission and the coastal agency find such multiple uses to be technically and economically feasible, they shall be required in the terms of the lease (or subsequently in the construction permit if not determined at that time).

(*f*) *Prevent Polluting Runoff.*—All water that contacts working surfaces of oil islands (including rain runoff) shall be contained and not allowed to drain in an untreated state into the ocean. Treatment shall be adequate to remove essentially all petroleum or chemical residues from the estimated maximum amounts of runoff water. [E–p21]

142. Minimize Impact of Onshore Facilities.—All onshore drilling, production, and onshore support facilities for offshore operations, including separation plants, pipelines, terminals and storage facilities, shall be designed and located to minimize their environmental impacts consistent with recovery of the resource. Prior to putting up leases for bidding, the State Lands Commission should submit its lease provisions relating to minimizing the environmental impact of anticipated associated facilities to the coastal agency. Where such development would result in substantial adverse impacts to the resources of the coastal zone, it shall be permitted only upon a demonstration that there is a need for the project, as specified in Policy 136 that alternatives would have a greater adverse environmental impact, and that there is little likelihood of improvement in technology that would substantially reduce such impacts in the immediate future (e.g., new technology for carrying out subsea production, oil and gas separation, storage, and natural gas liquefaction that might reduce the need for large onshore facilities). [E-p22]

143. Increase Oil Recovery Efficiency.—The California Legislature should: (1) enact legislation to require the California Division of Oil and Gas to regulate petroleum completion and production for individual wells, including setting maximum efficient rates of production, as analogous government agencies do in other major oil producing states; and (2) adopt a resolution calling for the Federal Energy Administration to encourage primary, secondary, and tertiary production from existing wells. [E-p24]

144. Disclose Exploration and Production Data.—The Legislature should enact legislation requiring that all original exploratory and production data from surveys or drilling of wells (including all logs, complete well histories, cores, drilling, cutting, water samples, chemical analyses, pressure and temperature measurements, etc.) be submitted within 60 days after finishing to the Division of Oil and Gas, with appropriate assurances of strict confidentiality, and shall be made public information one year after submittal, except that where such public disclosure would result in severe inequity to a well operator, year-to-year extensions of confidentiality might be granted by the Division of Oil and Gas. [E-p25]

145. Protection Aganist Any Adverse Impact of Federal OCS Development.—The Coastal Commission or the coastal agency, the California Legislature, the California congressional delegation, the State Lands Commission, the Division of Oil and Gas, and all other concerned agencies should seek agreement from the Department of Interior and other Federal authorities that Federal Outer Continental Shelf (OCS) leases will be approved by the Department of Interior only if the following conditions are met:

(*a*) *Demonstration of Need.*—Need for Federal OCS development off California must be clearly determined as required in Policy 136. [E-p27]

(*b*) Full consideration should be given to proposals that the Federal government sponsor all exploratory drilling on the OCS, either by contracting with private companies to perform the work, or by developing a governmental capability to do such drilling, in order to acquire full data about the OCS resources and its value prior to any leasing to private companies. [new]

(*c*) *Provide for Public Review.*—Opportunities for effective review of proposed OCS development plans must be provided for the general public, interested units of State, regional, and local government, and other segments of the communities most immediately effected by OCS development activities.

(*d*) *Develop and Disclose Long-Term Plans.*—One-, five-, and ten-year plans for petroleum production and all related development as described above in Policy 137, and their impacts on the California coast, should be fully developed and disclosed.

(*e*) *Prevent Drainage of State Petroleum Sanctuaries.*—The leases in question should be clearly separated from the State petroleum sanctuaries to prevent drainage of oil and gas reservoirs that may lie partially on State submerged lands.

(*f*) *Establish Stringent Safety Standards.*—Petroleum production under Federal jurisdiction off the California coast should be made subject to safety standards at least as stringent as those for production on State-regulated offshore areas (i.e., those contained in the California Division of Oil and Gas regulations and the manual of procedures of the States Lands Division).

(*g*) *Evaluate Unitization or Consolidation Possibilities.*—The possibility of unitization or consolidation of all operations and facilities should be fully evaluated and required where feasible, as described in Policy 139.

(*h*) *Consider Use of Subsea Systems.*—The possibility of use of submerged drilling, completion, and production systems that have been adequately tested to meet rigid environmental safety standards should be fully evaluated as a partial alternative to platforms.

(*i*) *Some OCS Revenues Should Go to States.*—The Federal government should agree to provide moneys to California (and to other coastal states) prior to leasing, with the funds to be reimbursed either through a fee related to production volumes, or by making available a portion of its revenues from OCS lease sales or production royalties, or by granting funds from some other source, to assist the State and local governments in planning for and overcoming or mitigating any adverse impact of this production (e.g., planning for transportation terminals, additional refineries, pipelines and storage areas, and other support facilities in a way that minimizes environmental impacts), and to assist the State and local governments to purchase land for recreation or provide other amenities along the coast to help offset the impact of OCS development.

(*j*) *Designate Sanctuaries in Certain Areas.*—Sites and tracts should be designated as sanctuaries (1) if they are unusually subject to the risk of oil spills due to geological seismic disturbance; or (2) if they offer unusual coastal aesthetic assets or the local economy is particularly dependent upon the protection of coastal aesthetic assets. Portions of the Santa Barbara Channel, Monterey Bay, and Santa Monica Bay would appear to be candidates for sanctuary status. [E–p27]

(*k*) *Compatibility with Coastal Plan Policies.*—Federal OCS development and related activities should be compatible with policies set forth in the Coastal Plan.

146. Prevent Subsidence; Reinject Oil Field Brines.—Liquid and gas extraction projects that could cause or contribute to subsidence hazard (where there is a potential for significant present or future property damage) shall not be permitted and existing operations stopped unless it is determined that there is no reasonable alternative. In such cases, the best available techniques for minimizing or preventing land subsidence shall be utilized. [G–p9] Lease or unit operators constructing new facilities shall reinject all oil field brines into oil producing zones unless injection into other subsurface zones will reduce environmental risks. Exceptions to reinjection will be granted only after submission to the coastal agency of detailed plans adequately providing for the elimination of petroleum odors and all potential fresh water or ocean water quality problems. [E–p23] Monitoring programs to record land surface and nearshore ocean floor movements shall be continued in all areas of subsidence problems and shall be initiated in locations of new large-scale fluid extraction on land or nearshore before operations begin. Such monitoring shall continue during and after liquid and gas extraction operations until surface conditions have stabilized. Costs of monitoring and mitigation programs shall be borne by liquid and gas extraction operations, overseen by an appropriate State agency. [G–p9]


PROCEDURAL LEASING FLOW CHART FOR O.C.S. OIL AND GAS PRODUCTION
ADDITIONAL REVIEWS AND
PROCEDURAL STEPS
CAUSED BY HR 6218
(STAFF WORKING DRAFT)
(1-30-76)
LEGEND


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ADDITIONAL REVIEWS AND PROCEDURAL STEPS CAUSED BY HR 6218 (STAFF WORKING DRAFT) (1-30-76)
T D HEWITT (CONOCO)
L E MACK (API)
22-76
ENVIRONMENTAL BASELINE STUDIES
MONITORING STUDIES BEGIN
Civil Suits may stop procedure at any point indefinitely
Cancellation of Lease at any time may stop procedure (HR 6218 Sec 5, Par 2)
LEGEND
BLM Bureau of Land Management
CEQ Council on Environmental Quality
Corps Corps of Engineers
CFR Code of Federal Regulations
DEIS Draft Environmental Impact Statement
DOI Dept of Interior
EBMS Environmental and Baseline Monitoring Studies
EIS Environmental Impact Statement
FEIS Final Environmental Impact Statement
FWL Fish and Wild Life Service
NEPA National Environmental Protection Act (1969)
NOAA National Oceanic and Atmospheric Administration
OCS Outer Continental Shelf
PDOD Program Decision Option Document
PH Public Hearing
RAB Regional Advisory Board
Secretary Secretary of the Interior
USCG United States Coast Guard
USGS United States Geological Survey
OIL WELL
GAS WELL
DRY HOLE
Current Reviews and Procedural Steps
Special Circumstances (Sometimes Done)
Additional Reviews and Procedural Steps caused by HR 6218
PROCEDURAL LEASING FLOW CHART FOR O.C.S. OIL AND GAS PRODUCTION (H.R. 6218)