April 1975

A. E. Res. 75

Atlantic Outer Continental Shelf Energy Resources: Economic Implications for Long Island

by

Robert J. Kalter

Wallace E. Tyner

Department of Agricultural Economics
Cornell University Agricultural Experiment Station
New York State College of Agriculture and Life Sciences
A Statutory College of the State University
Cornell University, Ithaca, New York

ATLANTIC OUTER CONTINENTAL SHELF ENERGY RESOURCES: ECONOMIC IMPLICATIONS FOR LONG ISLAND

Robert J. Kalter

Wallace E. Tyner

April 1975

Department of Agricultural Economics

Cornell University

Ithaca, New York 14853

This work is a result of research conducted under the auspices of the New York State Sea Grant Program, and sponsored by a contract with the Nassau-Suffolk Regional Planning Board.

Acknowledgements

The authors wish to acknowledge the assistance and support of Mr. DeWitt Davies of the Nassau-Suffolk Regional Planning Board and Mr. Donald Squires, Director of the New York State Sea Grant Program. In addition, the authors acknowledge the assistance of a number of other individuals from local and federal government, private industry, and the academic community. We are also grateful to John Broderick for his help in computer programming and to Lynn Hopkins who typed and proofread the entire paper. Of course, the authors are solely responsible for any errors contained in the paper.

EXECUTIVE SUMMARY

This study attempts to evaluate some of the potential economic impacts on Nassau and Suffolk counties of Long Island which could result from Atlantic Outer Continental Shelf (AOCS) leasing. The major conclusions of the study are briefly stated in this executive summary.

1. Based on economic and environmental (oil spill) criteria, a Long Island impact area was delineated to include prospective drilling areas which would be likely to have an impact on the Island. This area is bound by 39°30'N on the south, the New Jersey and Long Island coast lines (74°W) on the west, 41°N on the north, and 70°20'W on the east. Drilling and production within parts of this area could have significant economic and environmental impacts on Long Island.

2. Using two geological assumptions, concerning AOCS energy resource locations, a range of hydrocarbon reserve estimates for the impac area were developed. Reserves would likely range from .5 to .9 billion barrels of petroleum, but could range from 0 to 1.8 billion barrels, or higher. Natural gas reserves would likely range from 3.2 to 6.0 trillion cubic feet, but could range from 0 to 12.1 trillion cubic feet, or higher. These reserve estimates should be considered speculative, and were developed for purposes of analysis only.

3. Based on the reserve estimates and prior work by the authors, a hypothetical leasing schedule was prepared for each alternative assumption concerning hydrocarbon locations. Leasing in the Long Island impact area could begin as early as 1976 and continue for two to seven years given the assumptions of our analysis.

4. Oil and gas production could, then, commence as early as 1981 and continue beyond the year 2000. Using the .9 billion barrels reserve figure, peak oil production from the region would be less than 150,000 barrels per day (55 million per year). Natural gas production would be 959 million cubic feet per day (.35 trillion cubic feet per year). However, economic and environmental impacts could begin with exploratory drilling as early as 1976 or 1977.

5. Using a previously developed model designed to optimize private producer decisions, the time streams of production, investment and federal government revenue were generated, and the investment costs subdivided into various components such as exploration, platforms, and pipelines.

6. Total investment costs amounted to about $2.7 billion over the development period. The discounted value of federal government revenue from royalties and bonus payments came to $.7 billion, and from taxes $.4 billion for a total of $1.1 billion. If the

federal government should agree to grant states and localities 37 1/2 percent of bonus and royalty income, this could represent about $270 million in government income for the region (discounted).

7. Direct economic impacts on Long Island were estimated for both employment and sales. The employment impact would be no more than 6,300 workers, less than one percent of the existing Long Island work force. Sales impacts could range from $138 to $265 million.

8. Quantitative estimates of recreation and fishing losses due to oil spills were not developed due to inadequate data on physical phenomena. The analysis showed a minor chance of an oil spill affecting the Island from outside the impact area, but up to a one in three chance of a large spill beaching on Long Island from drilling sites within the impact area. Information needs and the analytical process need for further work in this area were discussed in detail.

9. Indirect impact multipliers were developed which could be applied to any direct impact estimates to derive the magnitude of indirect effects. These multipliers clustered in the area of 3.2.

10. The refinery location issue was evaluated with the aid of previous studies. It appears highly unlikely that future refineries would be located on Long Island. Hence, no refinery associated impacts were estimated.

11. From estimating recoverable reserves to projecting direct and indirect economic impacts, this analysis is fraught with uncertainty. Decision makers should consider not only the quantitative estimates but also the high degree of uncertainty in these estimates.

12. Finally, and perhaps most important, this analysis has <u>not</u> compared the economic conditions <u>with</u> and <u>without</u> AOCS oil leasing and development. It has only evaluated some of the likely effects of initiating AOCS production. It has not evaluated the likely regional development pattern in the absence of AOCS development. In particular, it has not estimated the economic or environmental impacts of increased petroleum imports (via tanker) into the region. The correct decision framework is to compare projected conditions <u>with</u> and <u>without</u> AOCS leasing, not <u>before</u> and <u>after</u> leasing.

This summary cannot possibly capture the totality of the analysis. Readers are urged to continue through the report in order to obtain a fuller understanding of the complexities and uncertainties involved in the analysis.

Despite the existing complexities and uncertainties, AOCS leasing decisions can and will be made. It is hoped that this analysis and those which have preceded it will assist Long Island officials in developing and advocating policy measures in the interest of the citizens of Long Island and of the United States.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF TABLES (Con't.)

LIST OF FIGURES

Atlantic Outer Continental Shelf Energy Resources:
Economic Implications for Long Island

INTRODUCTION

The nation faces a dilemma over energy policy. National security and considerations of economic independence seem to dictate the need for a reduction in energy imports. Most public officials, regardless of political orientation, agree on this point, although the extent and timing of any decrease is subject to less of a consensus. Yet to achieve any sizeable reduction, new sources of domestically produced energy will need to be developed and/or substantial changes in energy consumption must occur. In either case, the economic and social costs will be high. But what is the proper mix and timing of the actions required? The questions are obviously national in scope. There are no simple answers. The decision making process must begin with an analysis and comparison of the various alternatives available. In the end, however, the decisions must be made in the political arena where all of the various alternatives can be weighed with respect to their environmental, economic and social benefits and costs.

In this process, it is important that each region, affected by one or more of the alternatives, learn and communicate to decision makers as much as possible about the potential regional impacts. Only in this way, are such impacts likely to be given adequate consideration. On the east coast, one of the alternatives being proposed is development of the Atlantic Outer Continental Shelf (AOCS) for production of petroleum and natural gas. As a consequence, this study was commissioned by the Nassau-Suffolk Regional Planning Board in an attempt to better understand the economic impacts of such a development. Comprising the bulk of Long Island, these two counties are likely to be affected by any AOCS leasing activity undertaken by the Federal Government. On the other hand, so little is known about actual hydrocarbon resources on the AOCS that any evaluation of this type must be considered speculative. Nonetheless, policy decisions at the national level will be based on existing information, and this same pool of information can form the basis of an evaluation regarding Long Island.

Exogenous factors often affect the economic and social life of regions. Whether these impacts should be considered positive or negative by the region in question is not always a simple question to answer. Normally, any economic change can be expected to make certain sectors of an economy better off and others worse off. A region must face both this distribution question and the issue of whether the net impact of these forces will result in an overall gain or loss.

In the following discussion, three major issues will be considered. First, we will look at the potential impacts (both gross and net) of AOCS activities on employment and income within the Long Island region. When assessing alternative futures, however, it will be assumed that the most important aspects are net changes. Gross effects say nothing about overall well-being within a region. For most planning purposes, decision makers are interested in improvements in social welfare and net effects are a more useful indicator for this purpose. However, both the direct and indirect impacts on employment and income must be considered in evaluating net impacts. Second, required changes in the provision of and expenditures for public services should be separately evaluated. Only in this way can the local fiscal effects of AOCS leasing be understood and an appropriate basis for sharing public revenues derived. Third, potential changes in the recreation and fishing sectors due to offshore petroleum production will also be analyzed, since these activities are likely to be most heavily impacted by any adverse environmental considerations of AOCS development.

The remainder of this report is divided into three chapters. Chapter 2 reviews the AOCS production possibilities for the Mid-Atlantic region. Hypothetical reserve estimates by region are provided along with projected costs of exploration and development. Alternative assumptions on timing and location of offshore leasing are analyzed to determine the sensitivity of analytical results to the leasing schedule. In Chapter 3, the economic and social impacts of potential AOCS hydrocarbon production on Nassau and Suffolk counties are examined. Included in this analysis are potential impacts of exploration, development and productive activity. Their direct and indirect income and employment impacts will be the focus, but fiscal implications for local governments will also be reviewed. The onshore implications (i. e., refinery activity) of any OCS activity will be included in the analysis. A separate analysis of potential impacts on recreation and fishing will be provided, to the extent that data permits. Chapter 4 reviews the effects of information constraints on the analysis.

THE ATLANTIC OUTER CONTINENTAL SHELF: GEOLOGY, POTENTIAL RESERVES, PRODUCTION COSTS AND LEASING POSSIBILITIES

This chapter discusses the production possibilities and projected production costs for the Atlantic Outer Continental Shelf with particular emphasis on the Long Island area. Hypothetical petroleum reserve estimates by region are developed along with regional projections of production costs. Alternative assumptions on timing and location of offshore leasing are provided to test the sensitivity of the impact analysis to the characteristics of the leasing program.

Geology and Potential Reserves: For the AOCS, a wide range of speculative estimates of recoverable oil reserves have been calculated. This range is due, in part, to the different approaches used for evaluation of wildcat (unexplored) areas. There are two major approaches to calculating speculative reserves (Theobald). One approach, the geological, relates the area or volume of rock potentially containing oil or gas (sedimentary deposits) to known reserves of oil or gas in similar geologic areas. A second approach, the mathematical, projects future trends from past statistics and only implicitly considers trends in geological or technological factors. At the national level, the National Petroleum Council, the U. S. Geological Survey (1972), the Potential Gas Committee, Pratt, and Weeks all use the geological method of calculating reserves. Hubbert of U. S. Geological Survey (1974) and Moore use the mathematical approach (Council on Environmental Quality; Russell; Weeks; Theobald).

Speculative estimates of recoverable oil reserves on the AOCS range from 5 to 20 billion barrels of oil. Those using the mathematical approach to reserve estimation generally arrive at estimates in the low end of the range. The estimates presented and used in this study are based primarily on the geologic approach using the methods developed in a study by Spivak and Shelburne (p. 1306). They estimated the total volume of sedimentary rock on the AOCS and slope and used a factor of 71,000 barrels of oil per cubic mile of sedimentary rock to arrive at recoverable reserve estimates for the area north of the 33° parallel. This factor is based upon average recovery for all known hydrocarbon deposits in the United States. For the area south of the 33° parallel, a factor of 15,000 bbl. per cubic mile of sediment was used. This was based on estimates of ultimate production and volume of sedimentary rock in several basins of the United States similar geologically to the offshore areas of South Carolina and Georgia. Estimates of recoverable gas and natural gas liquids were calculated by applying the ratio of expected gas to oil production in the United States as a whole to the AOCS speculative oil reserve estimates. The factor for natural gas was 6.7 Mcf per barrel of crude oil. For natural gas liquids, the factor is .201 barrels per barrel of crude oil (p. 1308). Both associated and non-associated gas were included in the gas estimate.

Table 1 summarizes the Spivak and Shelburne estimates of speculative recoverable reserves for the AOCS. In addition, estimates from other sources

Table 1.--Estimates of Undiscovered Economically Recoverable Oil and Gas in the Atlantic OCS

	Recoverable Crude Oil (billion barrels)	Natural Gas (trillion cubic feet)
Spivak and Shelburne[1]	10.0	67.0
U. S. Geological Survey[2]	10-20	55-110
National Petroleum Council[3]	5.8	54.5
National Petroleum Council-Potential Gas Committee[4]	19	46
Potential Gas Committee[5]	--	35

[1]The Spivak and Shelburne estimates include 5.30 billion barrels of oil and 36.0 trillion cubic feet of natural gas for the Atlantic OCS north of latitude 33°, .20 billion barrels of oil and 1.0 trillion cubic feet of natural gas for the Atlantic OCS south of latitude 33°. They also estimate that there is 3.30 billion barrels of oil and 22.0 trillion cubic feet of natural gas north of latitude 33° on the continental slope and 1.20 billion barrels of oil and 8.0 trillion cubic feet of natural gas south of latitude 33° on the continental slope.

[2]The U. S. Geological Survey (1974) estimate includes both crude oil and natural gas liquids, so it may be 15 to 20 percent higher than for crude oil only.

[3]The National Petroleum Council (1972) estimate includes 10.75 billion barrels of oil-in-place for the Atlantic offshore area north of latitude 33°, 1.75 billion barrels for the offshore area south of 33° to the Florida boundary, and 1.90 billion barrels for the Florida offshore. The 14.4 billion barrels total was converted to ultimate production with a 40 percent recovery efficiency.

[4]The National Petroleum Council Committee on Possible Future Petroleum Provinces (1970) presents independent estimates of recoverable oil resources but uses the Potential Gas Committee's 1968 estimate for ultimate natural gas production from the Atlantic OCS.

[5]The Potential Gas Committee estimate includes the entire Atlantic offshore area, except Florida, to a depth of 1,500 feet (U. S. Geological Survey, "Comparison and Discussion of Some Estimates of United States Resources of Petroleum Liquids and Natural Gas," 1972).

are shown for comparison. All are based upon a geologic approach to hydrocarbon estimation. The variation in estimates can be explained by two principal factors: (1) the delineation of areal extent in the Atlantic and the feasible production areas designated for inclusion in the estimation process, and (2) the expected content of oil and natural gas deposits per unit of sedimentary rock (Council on Environmental Quality, pp. 2-14).

The two AOCS areas with the largest reserve potential are the Georges Bank and Baltimore Canyon areas. Georges Bank lies about 40 miles off Cape Cod. It is between 200 and 215 miles long and up to 25 or 30 miles wide at its midpoint. Water depth in the Bank varies from 250 to 660 feet and increases rapidly from 660 to 6,600 feet on the adjacent slope. Structure depth for the sedimentary rock underlying this area has been estimated at between .8 and 2.5 miles thick depending upon the specific sub-region in question. On the basis of these volume estimates and using the Spivak and Shelburne content coefficients, a median recoverable reserve estimate of 1.3 billion barrels of oil and 8.6 trillion cubic feet of natural gas is derived.

The Baltimore Canyon Trough lies off the Delaware and New Jersey coasts. It is approximately 125 miles long, about 50 miles wide at its center and 5 to 10 miles wide at its northern and southern extremes. Water depth in the Canyon and westward varies between 200 and 660 feet, with most of the area lying in 200 to 300 feet of water. On the continental slope, water depth rapidly increases to as much as 6,600 feet. Structure depth for the sedimentary rock underlying this area has been estimated at between 1.4 and 2.6 miles depending upon the specific sub-region in question. On the basis of these volume estimates and using the Spivak and Shelburne content coefficients, a median recoverable reserve estimate of 2.17 billion barrels of oil and 14.54 trillion cubic feet of natural gas is derived.

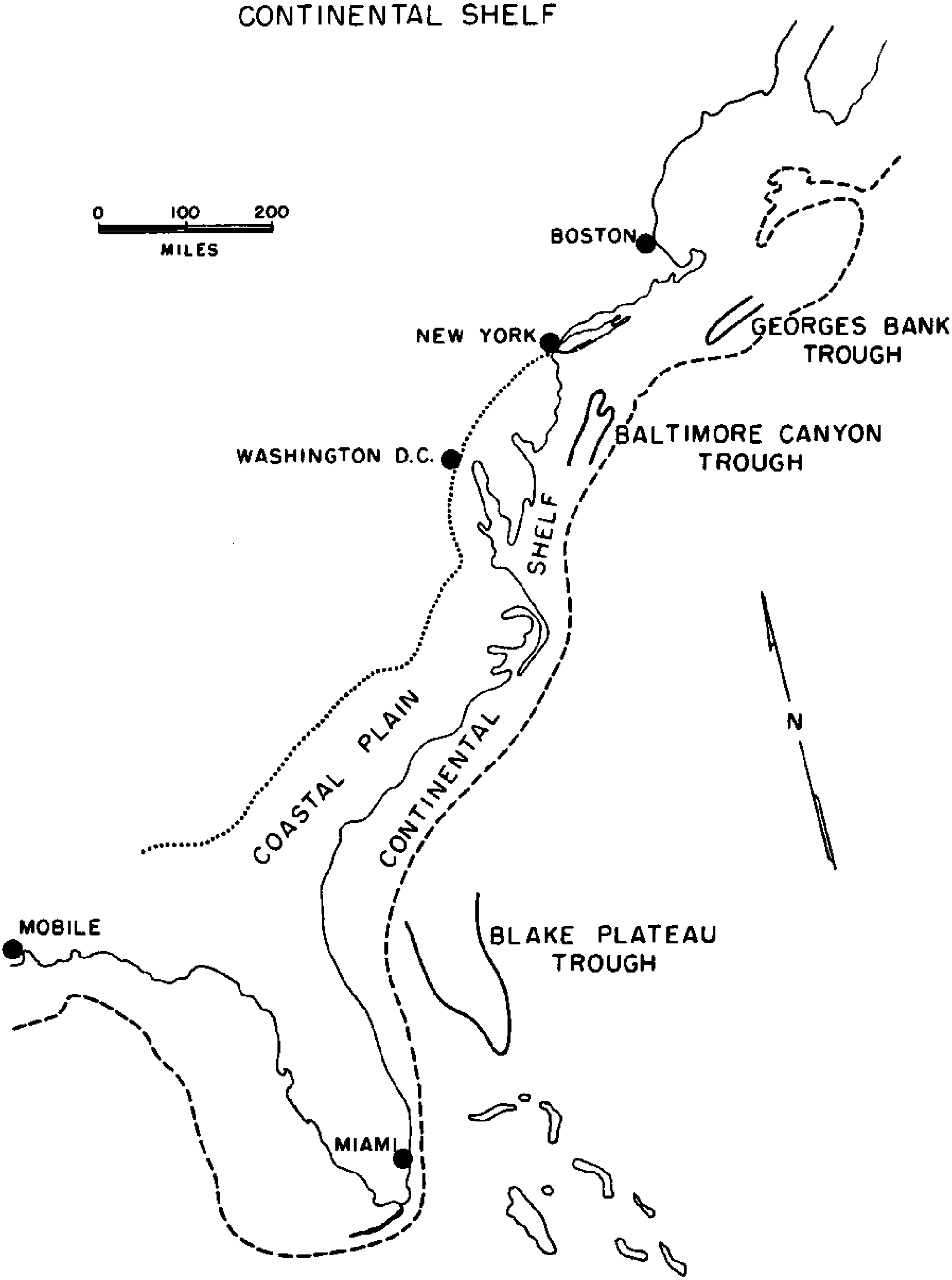
Georges Bank and the Baltimore Canyon were selected for special consideration because they are the most prominent and promising geologic features off the Atlantic coast. Most experts consider Baltimore Canyon as the area which offers the best potential for significant petroleum discoveries. The general location of these areas is shown in Figure 1. The remaining acreage on the Atlantic Outer Continental Shelf and slope was not subdivided to a comparable level of detail for this analysis. Rather, the total remaining area north and south of the 33° parallel is shown along with a breakdown between the continental shelf and the continental slope. Although substantial quantities of hydrocarbon deposits might be expected in these areas, in the aggregate, the extent of possible discovery zones does not warrant a further breakdown at this time.[1]

Table 2 summarizes the results of applying the Spivak and Shelburne estimation methods to sub-regional areas in the AOCS. Based upon our calcu-

---

[1]The area on the Atlantic OCS south of the 33° latitude has a substantially lower potential for oil entrapment than the area north of the 33° latitude. This lower potential is caused by the high percentage of carbonate rock in the area (Spivak and Shelburne, p. 1308).

FIGURE I. ATLANTIC COASTAL PLAIN AND CONTINENTAL SHELF



lations of areal extent for each sub-region (using U. S. Geological Survey maps), structure depth estimates for the various sub-regions (from Spivak and Shelburne) and their hydrocarbon content coefficients for the northern and southern AOCS, potential median resource values were calculated. For each median estimate, a high and low value was computed to bracket a probable range (based upon other studies). The spread was based upon a high value of twice the median and a low of one-half the median. The estimates assume that hydrocarbon deposits are spread uniformly over the designated spatial areas in proportion to the volume of sedimentary rock. Hence, potential resource values may be incorrectly distributed if hydrocarbon pooling has taken place in an alternate way (as is highly likely given the size of the regions being discussed). It is recognized that the geologic extrapolation approach is only valid for large areas and cannot be reliably used for estimates of small areas. Nonetheless, the regional and sub-regional extrapolations do offer one set of assumptions on hydrocarbon distribution which is useful for analysis. Alternative assumptions regarding the pooling of hydrocarbons can and will be utilized, as appropriate, in the subsequent evaluation to indicate the sensitivity of policy analysis to such factors.

In Table 2, the AOCS is subdivided into the major structural features of the Mid and North Atlantic -- the Baltimore Canyon and the Georges Bank areas, the Long Island impact area, and other shelf and slope areas. The resource estimates are classified by water depth in Table 3. Development of resources in water depths only up to 1500 feet was considered to be technically feasible within the time frame of this analysis.

The division between Mid and North Atlantic was somewhat arbitrarily set at 40°N for purposes of cost calculations in this study. The Long Island impact area was also subdivided at 40°N for purposes of analysis. South of 40°N the Long Island impact area consists of the northern portion of the Baltimore Canyon area and other shelf areas north of 39°30'N. The Baltimore Canyon area includes the Baltimore Canyon Proper, the area between the coast and the canyon, and the area between the canyon and the continental slope. In addition to these areas south of 40°N, the Long Island impact area also includes the area north of 40°N to 41°N bounded on the west by Long Island and on the east by 70°20'W. Hence, the total Long Island impact area is the area bounded by 39°30' on the south, 41° on the north, the New Jersey and Long Island coasts on the west, and 70°20'W or the continental slope on the east.

The Long Island impact area was derived using two separate criteria. The area was designed to incorporate all locations that would likely have an economic impact on Long Island through offshore support activities and/or all areas from which an oil spill would be likely to beach on Long Island. The first sub-area, the northern end of the Baltimore Canyon region, includes the area between 39°30'N and 40°N. Although there is up to a 20 percent chance of spills south of this area beaching on Long Island in the spring (with no clean up), the minimum time to shore was estimated at 54 to 61 days (Council on Environmental Quality, pp. 6-9) which allows time for clean up or dispersion of any spills that would occur. Probabilities in other seasons are much lower. Chances of spills beaching from this portion of the impact area, itself, are variable. In some sections of the area, any chance of a spill beaching

Table 2.--Potentially Recoverable AOCS Hydrocarbon Estimates by Sub-Region

AREA	Extent	Average Structure Depth	Volume of Sedimentary Rock
	Square Miles	Miles	Cubic Miles
<u>LONG ISLAND IMPACT AREA</u>			
Northern Baltimore Canyon Area (39°30' to 40°N)			
-Baltimore Canyon Proper	550	2.6	1,430
-Between the coast and the canyon	750	1.4	1,050
- Between the canyon and the slope	390	2.0	780
Other Shelf Area between 39°30' and 40°N	650	1.0	650
Shelf Area between 40°N and 41°N and L.I. and 70°20'W	8,800	1.0	8,800
<u>OTHER ATLANTIC OCS AREAS</u>			
Georges Bank Area			
-Georges Bank Proper	4,400	1.6	7,040
-East of the Bank and west of the slope	8,800	.8	7,040
-Continental Slope	1,650	2.5	4,125
Baltimore Canyon Area			
-Baltimore Canyon Proper	4,950	2.6	12,870
-Between the coast and the canyon	4,250	1.4	5,950
-Between the canyon and the slope	910	2.0	1,820
-Continental Slope	2,250	3.0	6,750
<u>OTHER MID AND NORTH ATLANTIC SHELF AREAS</u>	26,550	1.0	26,550
<u>OTHER MID AND NORTH ATLANTIC SLOPE AREAS</u>	18,000	1.9	34.200
TOTAL N. 33°N			
<u>SHELF-SOUTH OF 33°</u>	13,600	1.1	15,000
<u>SLOPE-SOUTH OF 33°</u>	21,200	3.7	78,400
TOTAL S. 33°			
TOTAL AOCS			
TOTAL DEVELOPMENT POTENTIAL AOCS[1]			

[1]Based on all areas in less than 1500 feet of water depth.

Source: Calculations based on National Petroleum Council (1973) and Spivak and Shelburne data.

Oil			Gas			Natural Gas Liquids		
Billion Barrels			Trillion Cubic Feet			Billion Barrels		
median	high	low	median	high	low	median	high	low
.90	1.80	.45	6.03	12.06	3.02	.17	.34	.09
.23	.46	.12	1.54	3.08	.77	.04	.08	.02
.10	.20	.05	.67	1.34	.34	.02	.04	.01
.07	.14	.04	.47	.94	.24	.01	.02	.01
.06	.12	.03	.40	.80	.20	.01	.02	.01
.05	.10	.03	.34	.68	.17	.01	.02	.00
.62	1.24	.31	4.15	8.30	2.08	.12	.24	.06
1.29	2.58	.65	8.64	17.28	4.33	.26	.52	.13
.50	1.00	.25	3.35	6.70	1.68	.10	.20	.05
.50	1.00	.25	3.35	6.70	1.68	.10	.20	.05
.29	.58	.15	1.94	3.88	.97	.06	.12	.03
1.94	3.88	.98	13.00	26.00	6.50	.39	.78	.20
.91	1.82	.46	6.10	12.20	3.05	.18	.36	.09
.42	.84	.21	2.81	5.62	1.41	.08	.16	.04
.13	.26	.07	.87	1.74	.44	.03	.06	.02
.48	.96	.24	3.22	6.44	1.61	.10	.20	.05
1.89	3.78	.95	12.66	25.32	6.33	.38	.76	.19
2.43	4.86	1.21	16.28	32.56	8.14	.49	.98	.24
8.45	16.90	4.23	56.61	113.22	28.32	1.70	3.40	.85
.23	.46	.12	1.54	3.08	.77	.05	.09	.02
1.18	2.36	.59	7.91	15.82	3.96	.24	.47	.12
1.41	2.82	.71	9.45	18.90	4.73	.29	.56	.14
9.87	19.74	4.94	66.14	132.28	33.07	2.00	3.98	.99
5.71	11.42	2.86	38.27	76.54	19.14	1.16	2.32	.58

Table 3.--Potentially Recoverable AOCS Hydrocarbon Estimates by Water Depth

AREA	Median Oil Estimate by Water Depth				
	0-600'	600-1500'	Sub-Total Less Than 1500'	1500'	Total
	Billion Barrels				
LONG ISLAND IMPACT AREA	.90		.90		.90
OTHER MID- AND NORTH ATLANTIC AREAS					
-Baltimore Canyon area	1.46	.02	1.48	.46	1.94
-Georges Bank area	1.00	.02	1.02	.27	1.29
-Other shelf areas	1.89		1.89		1.89
-Other slope areas		.12	.12	2.31	2.43
TOTAL-NORTH OF 33°N	5.25	.16	5.41	3.04	8.45
SHELF-SOUTH OF 33°N	.23		.23		.23
SLOPE-SOUTH OF 33°N		.06	.06	1.12	1.18
TOTAL-SOUTH OF 33°N	.23	.06	.29	1.12	1.41
TOTAL AOCS	5.48	.22	5.70	4.16	9.86

on the Island would be remote (Devanney and Stewart, February 1974). However, Long Island could potentially serve as a base of operations for OCS development in the area, so it was included. In general, it was assumed that a base of operations would not be established more than 100 air miles from the drilling and production area. This distance could be substantially reduced, however, if logical alternatives to Long Island exist at a more reasonable distance.

The second sub-area of potential leasing and production which could affect Long Island is the area east and southeast of Long Island and immediately north of the Baltimore Canyon area. This area is approximately bound by 40°N (on the south), 74°W, Long Island, 41°N, and 70°20'W (on the east). Beyond this area the probability of a spill reaching shore on Long Island is always 10 percent or less, and usually much lower (Devanney and Stewart, November 1974). There is little chance of a spill reaching Long Island from the Georges Bank Area (Council on Environmental Quality, pp. 6-7). Exploration and production facilities located anywhere in this impact area could feasibly be serviced from a Long Island base.

Production Costs: AOCS production costs will be composed of investment and operating components. These components can, however, differ for the various types of hydrocarbon discoveries (oil or natural gas), for various water and structure depths and for different climatic conditions. In analyzing regional impacts of OCS activity, information on these factors and their components is needed to ascertain some of the potential onshore linkages and their magnitude. The following discussion will treat the overall production cost issue. The overall magnitudes involved for the Long Island impact area and the respective components of those totals will be taken up at a later point.

A number of factors make up the investment costs required if primary production from hydrocarbon reservoirs is to take place. For convenience, they can be subdivided into two categories: exploration and development costs. Exploration costs include those elements involved in determining the location of hydrocarbons in preparation for drilling development wells and initiating production. Development costs encompass a host of elements required to install production wells, initiate production activity, transport field output to established shore facilities and abandon a depleted field.

Several methods are commonly used to display per unit exploration and development costs.[2] One approach calculates investment cost per barrel of ultimate production (total recovery from the reservoir). Another displays costs on the basis of a "new daily barrel" or "per barrel of daily capacity." That is, the investment cost required to produce a barrel of output daily per year long period. Finally, a variant of the "new daily barrel" approach can be used -- the cost per unit of installed (or peak) annual capacity. This is equivalent to dividing the "new daily barrel" approach by 365. Given the models used to simulate leasing behavior, the latter definition will be used in this study (Kalter, et al., 1974). The result can be compared with the cost per ultimate barrel approach, however, only by making limiting assumptions with respect to factors like field life, decline rate and installed capacity. Since these factors are products of our model, the definition cannot be used for analytical purposes.

Generally, all exploratory activities, beginning with geophysical and geological surveys and concluding with the drilling of exploratory wells, are included in exploration costs. However, for an analysis of leasing behavior, only the cost of exploratory wells should be included since most of the geological and geophysical surveying will be done prior to the lease sale. Therefore, these costs can be considered sunk in terms of an investment decision. Furthermore, the cost of geological and geophysical surveys is minimal compared to other exploration and production elements (U. S. Department of the Interior, 1970, pp. 189-191). The cost of exploration, then, is a function of the cost of each exploratory well and the number of wells which are drilled on any given structure or tract. The number of wells required to

---

[2] Another display often used is that of total system investment costs, rather than per unit values. Given associated estimates of factors like reservoir size, these can be translated to a value on the schedule of unit costs.

explore a structure and the discovery efficiency (success ratio) varies significantly among structures (Weaver, p. 13). Discovery efficiency offshore generally averages 10 percent or less, meaning that 10 percent of the exploratory wells are successful in locating commercial hydrocarbon deposits (American Petroleum Institute, Quarterly Review, 1974).

In estimating AOCS exploration costs, estimates from known areas will be used as baseline information from which extrapolations can be made. In this regard, Gulf of Mexico data appears most relevant and appropriate. The National Petroleum Council (Ocean Petroleum Resources, p. 9) has estimated the cost of an exploratory well in the Gulf of Mexico (in 200 meters of water) at $2.7 million. They estimate that nine exploratory wells would be drilled for the average reservoir resulting in exploratory costs of $24.3 million.[3] Exploration costs would not be expected to vary significantly by type of hydrocarbon deposit or by reservoir size.

Development costs are a function of a number of variables. Some of these are platform costs, water depth, structure depth (drilling depth), percentage of dual completions, dry hole risk factors, drilling difficulty, labor costs, climate, and others. As with exploration costs, Gulf of Mexico cost data can be determined and extrapolated to the AOCS.

Several studies have estimated development costs, by component, for the Gulf. In a draft working paper, NPC scientists have calculated average development costs for application to three reservoir sizes. Coupled with the exploratory costs discussed previously, these estimates provide a basis for determining the total investment costs of reservoirs in the Gulf. NPC assumes that the same exploratory and development expenses will apply to each of the three reservoir sizes considered. Table 4 details these estimates, adjusted to present values.

The production capability of each system is determined by reservoir characteristics. The first system has a peak capacity of approximately 15,000 bbl./day assuming 500 bbl./well/day X 36 producing wells X a .9 maximum efficient rate (MER) constraint on production. The second system has a peak capacity of 30,000 bbl./day assuming 1,000 bbl./well/day and the third system has a peak capacity of 50,000 bbl./day assuming 1,500 bbl./well/day. No secondary or tertiary production costs are included in these estimates. To determine the cost per unit of installed capacity, these oil production rates are adjusted for production of associated gas and natural gas liquids. Converting on a revenue basis, using a $.50 price for gas and a $11 price for natural gas liquids, the oil equivalent peak production levels become 16,517, 33,033, and 55,025 bbl./day. Costs per unit of installed capacity, in 1974 dollars, for each reservoir size are $17.86, $8.93, and

---

[3]A reservoir is not necessarily coterminous with a leasehold. However, unitization is assumed in the analysis. Thus, when reduced to per unit values the derived cost figures can be used for comparable locations and reservoir sizes. Since this study deals with rather broad spatial areas, values pertaining to the average reservoir are appropriate.

Table 4.-- Gulf of Mexico Investment Costs (200 meter water depth)

Cost Component	$ in millions	
Development		
2 platforms @ $15 million/unit	$ 30.0	
40 development wells @ $.5 million/unit	20.0	
60 miles of 20" pipeline @ $15,000/inch/mile	18.0	
2 sets of production facilities @ $5 million/unit	10.0	
Storage	2.0	
Future field improvements (recompletions)*	1.6	
Field abandonment*	1.8	
Total development costs		$ 83.4
Exploratory		
9 wells @ $2.7 million/unit		24.3
Total investment costs		$ 107.7

*Discount to present value using a 12 percent rate, year 8 for future field improvements and year 15 for abandonment.

$5.36, respectively. This is equivalent to $6,521, $3,260, and $1,956 per new daily barrel.

As a check on these values, several other studies were reviewed. A study done for the Bureau of Mines used another approach for calculating petroleum production costs in the Gulf (U. S. Department of the Interior, Bureau of Mines, 1972). This study calculated all development costs for a 20 and a 30 year oil production model. For the 20 year model, development costs were $32.5 million and installed (peak) capacity was 3,332,000 barrels per year. Costs per unit of installed capacity were $9.75 or $3,560 per new daily barrel. For the 30 year model, cost per unit of installed capacity was $13.34 or $4,869 per new daily barrel. These costs included the development of associated gas and condensate production. Converting these outputs to oil equivalents, the costs per unit of installed (peak) capacity became $8.42 and $11.17, respectively, or $3,073 and $4,077 per new daily barrel. It is not clear in what year these costs were calculated but they appear to be about 1970.

Another study used the cost per barrel of ultimate production approach to cost estimation (U. S. Department of the Interior, 1970). That study calculated all the various exploration and development components and presented the costs per barrel of recoverable reserves added. For the Gulf of Mexico, a range of $1.30 to $1.35 per ultimate barrel resulted. Since no reserve figures were indicated, these results were coupled with several of the NPC reserve and capacity figures. This provides data for a rough order of magnitude comparison to other methods. Using the NPC reservoir of 65 million barrels with a 30,000 barrel peak daily capacity, the costs were $7.87 per unit of installed capacity and $2,871 per new daily barrel. With the NPC reservoir of 175 million barrels and 50,000 barrel peak daily capacity, the costs were $12.71 per unit of installed capacity and $4,638 per new daily barrel. These figures are calculated using $1.325 per ultimate barrel of production. The values are probably in 1968 dollars, but it is not specified in the study.

Table 5 lists the adjusted cost estimates by source and year. This comparison may be misleading, however. Without knowledge of the underlying assumptions used in each approach, derivation of a common unit for display may be inaccurate. As indicated above, underlying assumptions are often not given by the various data sources. For example, the method used to convert cost per ultimate barrel of production to cost per unit of initial capacity was forced to utilize two data sources which were not necessarily commensurate. Nonetheless, the comparison given in Table 5 is useful to gain a rough order of magnitude understanding of production costs on the Gulf.

In reviewing Table 5, the following technical issues should be kept in mind:

1. Figures derived from NPC data assume that total investment costs do not vary with reservoir size. This is clearly a simplification of the real world. Obviously, the number of platforms, well development costs, pipeline costs, and production facility installations can vary with reservoir size. Although the relationship between total costs and the reservoir size may not be linear, the NPC approach would tend to overestimate investment costs for small reservoirs. Consequently, the average NPC per unit investment costs, which are a weighted average of the costs for the three reservoir sizes assuming equal proportions for weights, may be somewhat overstated. It is likely that per unit investment costs actually take on the form of a step function over a range of reservoir sizes.

2. Cost estimates from the three sources listed in Table 5 may relate to different water and structure depths. For example, although the NPC estimates refer to a water depth of 200 meters (600 feet) the Bureau of Mines data relates to 33 meters (100 feet) and the Bureau of Land Management studies to 100 meters or less (300 feet). As a result, per unit costs should be somewhat lower but this would depend upon changes in technology and other factors.

3. The 1968 and 1970 estimates from the Bureau of Mines and the Bureau of Land Management bear an unknown relationship to current production costs on the Gulf. Inflation has tended to increase unit costs since the earlier studies. However, increases in efficiency and technological advances have probably lowered unit costs over the same time period. The net effect of these two forces is uncertain.

The estimates relating to the Gulf of Mexico can be compared with recent studies on the North Sea. It is apparent from these studies that a consider-

Table 5.--Development and Exploration Costs

Source		Unit of Installed Capacity	New Daily Barrel	Year
GULF OF MEXICO				
NPC - 15,000 bbl./day	$	17.86	$ 6521	1974
NPC - 30,000 bbl./day		8.93	3260	1974
NPC - 50,000 bbl./day		5.36	1956	1974
NPC - average*		10.71	3911	1974
Bur. of Mines - 20 yr. (oil only)		9.75	3560	1970
Bur. of Mines - 30 yr. (oil only)		13.34	4868	1970
Bur. of Mines - 20 yr. (tot. Hydroc.)		8.42	3074	1970
Bur. of Mines - 30 yr. (tot. Hydroc.)		11.17	4076	1970
BLM applied to NPC - 30,000 bbl.		7.87	2871	1968
BLM applied to NPC - 50,000 bbl.		12.71	4638	1968
NORTH SEA				
Lenning		7.73	2820	1974 (Mar.)
Ocean Construction		20.55	7500	1974 (Nov.)

*Derived by calculating a weighted average of the three NPC reservoir sizes assuming equal weights.

able escalation in investment costs may have taken place recently. However, estimates derived from NPC data tend to bear an appropriate relationship to those of the North Sea, given the locational variations in the two areas. The exception to this is the value for a 15,000 barrel per day reservoir. As indicated above, this value may be excessively high because of the manner in which it was calculated.

AOCS Extrapolation: Given a review of the available investment cost estimates for oil production in the Gulf of Mexico, the next step is to choose an appropriate value (or range of values) for extrapolation to AOCS conditions. Given their currency and apparent consistency with other studies, it appears that the estimates derived by members of the National Petroleum Council would be most appropriate for this purpose.

It must be recognized, however, that unit costs derived from NPC data may not properly specify the relationship between investment and initial installed capacity over various reservoir sizes. Moreover, to obtain an average cost over all reservoirs, the distribution of reservoirs by size must be known. For lack of appropriate information, we assume that equal installed capacities would exist among the three sizes discussed. Implicit is the assumption that equal weights reflect the a priori beliefs of prospective bidders about the distribution. The complex relationships between total initial investment, reservoir size and other geologic characteristics, economies of scale in investment, and other factors determining cost per unit of installed capacity need to be the subject of further research. Nonetheless, we believe the approach used here is an adequate first approximation for this analysis.

Indices necessary to extrapolate Gulf of Mexico cost data to the AOCS have been prepared by the NPC for both exploration and development costs (Ocean Petroleum Resources, pp. 9-11). These values are reproduced in Tables 6 and 7. One difficulty with applying these values to the AOCS is that only the North and South Atlantic are classified, not the Middle Atlantic. Yet the Baltimore Canyon, one of the more promising areas for exploration, lies in the Middle Atlantic. On the basis of conversations with government officials, however, cost estimates for the Middle Atlantic were prepared using the midpoint of two climatic conditions -- moderate and severe. For this purpose, Middle Atlantic was defined as the area between the 33° and the 40° parallels.

Another difficulty with the NPC extrapolation values lies in the fact that they pertain only to water depths of 200 meters or greater. Some geologically promising areas in the AOCS may be in lesser water depths. In that case, costs may be somewhat overestimated, although the magnitude is probably not large.

Table 8 summarizes AOCS production cost estimates for 200 meter water depths, based upon application of NPC extrapolation indices to Gulf of Mexico cost estimates derived from NPC data. An estimate is provided for each of the three reservoir sizes and the average. The average value is the mean cost of the three sizes. Estimates for other than 200 meters are not shown because their values, using current technology, make these areas economically marginal for development. When appropriate, however, they can be calculated in a similar manner.

Operating costs for primary recovery of petroleum are less ambiguous than investment costs. A number of sources indicate that such costs in the Gulf of Mexico are approximately \$.50 per barrel (U. S. Department of the Interior, 1970; Weaver; National Petroleum Council, 1974). For the AOCS, we will use a value of \$.55 per barrel based upon our conversations with industry people.

Non-Associated Natural Gas: In the previous discussion, all joint exploration costs were attributed to oil discovery. In calculating production costs for non-associated natural gas, we will maintain the same assumption. Therefore, only the development portion of investment costs will be considered here.

Table 6.--Offshore Exploration Expenditure Indices
(1.0 = $2.7 million per well in 1974 dollars)

Water Depths (Meters)		Climatic Conditions		
		Mild (1)	Moderate (2)	Severe (3)
200	(660')	0.8	1.0	1.8
500	(1,650')	1.0	1.3	2.1
800	(2,640')	2.3	2.6	3.3
4,000	(13,200')	3.8	4.0	4.3

Note: Typical of the various climatic conditions are:

(1) Senegal, Gabon, Honduras, Mediterranean, Java Sea, Persian Gulf.

(2) Gulf of Mexico, South Atlantic, South Pacific, Northwest Australia, Sea of Japan, Yellow Sea.

(3) North Sea, Bay of Biscay, South Australia, Gulf of Alaska, North Atlantic, North Pacific, West Coast of Canada, Nova Scotia.

Table 7.--Offshore Development and Production Expenditure Indices (1.0 = $95 million per system in 1974 dollars)

Water Depth (Meters)		Climatic Conditions		
		Mild (1)	Moderate (2)	Severe (3)
200	(660')	0.9	1.0	2.8
300	(990')	---	---	6.2
500	(1,650')	2.7	3.0	---
1,000	(3,300')	4.3	4.8	10.2

Note: Typical of the various climatic conditions are:

(1) Senegal, Gabon, Honduras, Mediterranean, Java Sea, Persian Gulf.

(2) Gulf of Mexico, South Atlantic, South Pacific, Northwest Australia, Sea of Japan, Yellow Sea.

(3) North Sea, Bay of Biscay, South Australia, Gulf of Alaska, North Atlantic, North Pacific, West Coast of Canada, Nova Scotia.

Table 8.--Atlantic OCS Production Cost Estimates Per Unit of Installed Capacity for 200 Meter Water Depth

	Low	Medium	High	Average
South Atlantic	$ 5.36	$ 8.93	$ 17.86	$ 10.71
Mid Atlantic	9.66	16.11	32.21	19.33
North Atlantic	13.80	23.00	45.99	27.60

Although this is an approximation of the actual situation, it is a reasonable approach to apply in wildcat areas as long as the value of crude oil maintains its current high differential with natural gas.

The development cost for non-associated gas should be substantially lower than that for oil reservoirs. Fewer wells would have to be drilled for a comparable size reservoir perhaps eliminating the need for additional platforms. Storage costs would be substantially lower, and other cost components (such as transportation) would be reduced (Ellis, 1974). It is estimated that the development cost for non-associated gas would be about two-thirds of the cost for an oil reservoir. Moreover, the production and decline rate for non-associated natural gas are often institutionally determined. That is, the production rate often must be set low enough to assure a steady supply of gas to meet long term contractual obligations. Hence, production level and decline are a function not only of reservoir characteristics and economic variables but also of institutional constraints. For purposes of per unit cost calculations, the installed capacity will assume that recoverable reserves are depleted in 18 years with a flat production profile. Cost per unit of installed capacity for non-associated gas may then be calculated. Using component cost estimates developed in an earlier study (Department of the Interior, 1970, pp. 205-208) and assuming an 18 year production horizon with a .001 production decline rate, the cost per unit of installed capacity is approximately $1.10 per Mcf in the Gulf. This figure represents the incremental cost of developing a natural gas field assuming that the exploration expenses are allocated to oil production. This cost estimate may be compared with a cost figure of about $1.60, which includes exploration expenses, obtained from proprietory sources. Hence, the estimate appears to be approximately correct. However, more empirical research is needed for verification.

Operating costs for natural gas production ranged from $.04 to $.06 per Mcf in the Interior study (Department of the Interior, 1970, pp. 206-208). In the subsequent analysis an operating cost of $.05 per Mcf will be used.

<u>A Hypothetical Leasing Program</u>: There are over 75 million acres offshore on the Atlantic shelf and slope. Of this, about 49 million acres are in less than 1500 feet of water and thus suitable for commercial development with current technology. In designing a probable, but hypothetical, leasing program for the AOCS, we assumed that two-thirds of the acreage available for commercial development would be nominated for lease sales by the existing nomination process. Thus, 33 million acres would be offered over the life of the program. Historically, about half the acreage nominated and offered for sale is actually leased by producers.

We further assumed that all the potential AOCS oil and natural gas reserves are located under the acreage actually offered and purchased for development. These assumptions, however, are not crucial to the analysis. On the other hand, the magnitude of estimated reserves is central to the evaluation. For purposes of exposition, we will use the median resource estimates from Table 2. These values can be easily varied to test other forecasts.

Alternative annual sale scales were considered for our hypothetical leasing program. Because of the low level of expected reserves relative to domestic demand, a three million acre annual offering was selected for analysis. This would permit rapid development of the reserves present yet be physically and institutionally feasible. An annual sale of this size results in an eleven year leasing program for the AOCS under our initial assumption of 33 million acres to be offered. Obviously, any alternative rate could be evaluated, but the rate chosen appears most likely at this writing.

The order in which specific areas would be leased was decided on the basis of reserve potential and expected economic return. From the reserve estimates in Table 2, each sub-region was ranked according to the barrels of oil per acre. Using a lease offering of three million acres per year, sub-regions were leased in order of the expected petroleum concentration derived above subject to an economic return constraint. In some cases the profitability constraint caused changes in the lease ordering because of expected differences in production costs. For example, the Baltimore Canyon area would likely be leased before the Georges Bank because of the significantly lower investment costs. Similarly, potentially productive areas on the continental slope would be leased last because of the significantly higher investment costs. A complete leasing schedule, based on these criteria, for the eleven years is given in Kalter, et al., 1974.

For nonspecific broad areas such as Other North Atlantic shelf, it was assumed that the petroleum was equally divided over the area offered for lease. This assumption is important only insofar as it affects the timing of sales and location of reserves. Alternative assumptions could easily be employed. For the nonspecific Atlantic shelf and slope areas north of 33°, it was assumed that one-half would be considered North Atlantic and one-half Mid-Atlantic for investment cost purposes. The Mid-Atlantic areas are leased first because of greater expected economic return.

The other factor affecting a projected lease program is expected production lags after the lease is granted. In the Gulf of Mexico, a three year production lag is common. However, since there has been no drilling or facility development off the U. S. Atlantic coast, the initial production lags are expected to be higher. A five year production lag was assumed for sales during the first year of leasing and a four year lag for those in the second. All future sales were assumed to have a three year production lag. The initial lags assume leasing begins no sooner than 1976. Hence, the earliest production would be expected in 1981.

Issues of sale scale, location and anticipated production lags raise a number of other interesting and important aspects related to a leasing program. Examples include the effects of manpower and equipment constraints or the implication of obtaining improved (public) geologic information prior to government leasing. These issues are not analyzed here. In not treating with these and other related issues, we are not denying their importance; quite the opposite, for they deserve a full analytical treatment which was beyond the scope of this analysis, but which will be possible at a later date.

A leasing schedule for the Long Island impact area is given in Table 9. This schedule is derived from the hypothetical leasing schedule developed by the authors in a previous paper (Kalter, et al., 1974, pp. 68-69). Leasing in the Long Island impact area could begin as early as 1976 (year 1) and continue through 1982 (year 7). A total of 4.8 million acres could be offered for lease in the area containing .9 billion barrels of oil and 6 trillion cubic feet of natural gas. Although leasing was assumed to begin in 1976, production was not projected to begin until 1981 because of an initial lag in production of five years.

The area between 39°30'N and 40°N (the northern Baltimore Canyon area) would be leased in the first four years of the leasing program. One million acres would be offered for lease over the four year period potentially containing .3 billion barrels of oil and 1.9 TCF of natural gas. This area contains CEQ drilling site 5 (Council on Environmental Quality, p. 63).

Table 9.--Hypothetical Leasing Schedule for the Long Island Impact Area

Years	Year Nos.	Area	Acres Offered (million)	Oil (bil. bbl.)	Gas (TCF)
1976-77	1-2	Baltimore Canyon Area	.72	.23	1.54
1978-79	3-4	Other Mid-Atlantic Area	.28	.05	.34
1980-82	5-7	E-SE of Long Island	3.75	.62	4.15
		TOTAL	4.75	.90	6.03

The area between 40°N and 41°N, east-southeast of Long Island would be leased in years 5-7 (1980-82) of the leasing program. The 3.8 million acres offered could contain .6 billion barrels of oil and 4.2 TCF of natural gas. Production in this area could commence in 1983 assuming a 3 year lag for development.

In summary, about 4.8 million of the 33 million acres projected to be leased (14 percent of the total) could have an impact on Long Island. This area could contain about .9 billion barrels of oil, 6.0 trillion cubic feet of natural gas, and .2 billion barrels of natural gas liquids (about 16 percent of the estimated AOCS recoverable reserves). If leasing begins in 1976, production could commence in 1981 and continue for 21 years through 2001 (Kalter, et al., 1974).

An alternative hydrocarbon pooling assumption could be used to test the sensitivity of the results to the volumetric assumption used. It is highly unlikely that amounts of hydrocarbon deposits greater than the estimates given above would be found in the areas listed as other Mid or North Atlantic (such as the area east-southeast of Long Island). These areas are not nearly as promising geologically as the areas with much deeper structure depths.

The most logical alternative is to assume that hydrocarbon deposits are concentrated in the most promising geologic formations. For the Mid- and North Atlantic, these would be the Baltimore Canyon and the Georges Bank. Thus, in deriving alternate estimates based on this assumption, we presume that all hydrocarbon deposits previously estimated for the continental shelf north of 33°N (5.3 bil. bbl.) are concentrated in Baltimore Canyon and Georges Bank shelf areas with sedimentary deposits at least 1.5 miles deep. Within these areas, it is assumed that deposits are divided in proportion to the volume of sedimentary rock. This assumption provides a polar extreme to the equal distribution assumption used above.

Table 10 provides the alternative reserve estimates by sub-region based on total petroleum deposits of 5.26 billion barrels on the shelf north of 33°N. Using these median reserve estimates, about .5 billion barrels of oil, 3.2 trillion cubic feet of natural gas and .1 billion barrels of natural gas liquids could be found in the Long Island impact area. All of this could be located at the northern end of the Baltimore Canyon south of 40°N (one promising area is about 60 miles south of Long Island and 60 miles east of New Jersey). Most of this resource would be leased in the first two years of an accelerated leasing program. Production could be expected to begin in 1981 and continue for at least fifteen years.

The timing of both reserve scenarios assumes a rapid leasing and development program; results could be quite different under alternative schedules. If the AOCS were leased at a slower rate, but reserve figures remain unchanged, essentially the same impacts could be expected, but spread out over a longer time period. Reduced spill impacts could possibly occur if technological advances in exploration and production were made over the longer development time period. However, this difference would probably be minimal considering that production is not expected to begin until 1981 in either case. The impacts on Long Island would also be different if alternative reserve figures were used. Since all AOCS reserve figures are hypothetical, the analysis in Chapter 3 will be conducted using impact area reserve figures of 50 percent and 150 percent of the two alternatives listed above. The median reserve estimates for the two alternatives range from .5 to .9 billion barrels of oil. The combined low to high range is from .25 to 1.80 billion barrels of oil. For natural gas the range is from 1.6 to 12.1 trillion cubic feet. Economic impacts will be estimated for this range of reserve estimates for the Long Island impact area. In this way, the sensitivity of the analytical results to petroleum discovery rates can be tested.

Table 10.--Potentially Recoverable AOCS Hydrocarbon Estimates by Sub-Region

AREA	Extent	Average Structure Depth	Volume of Sedimentary Rock	Oil			Gas			Natural Gas Liquids		
				Billion Barrels			Trillion Cubic Feet			Billion Barrels		
	Square Miles	Miles	Cubic Miles	median	high	low	median	high	low	median	high	low
LONG ISLAND IMPACT AREA				.48	.96	.25	3.22	6.43	1.61	.09	.19	.05
-Baltimore Canyon Proper	550	2.6	1,430	.31	.62	.16	2.08	4.15	1.04	.06	.12	.03
-Between the canyon and the slope	390	2.0	780	.17	.34	.09	1.14	2.28	.57	.03	.07	.02
OTHER AOCS AREAS				4.78	9.56	2.40	32.03	64.05	16.01	.96	1.92	.48
-Georges Bank Proper	4,400	1.6	7,040	1.55	3.10	.78	10.39	20.77	5.19	.31	.62	.16
-Baltimore Canyon Proper	4,950	2.6	12,870	2.83	5.66	1.42	18.96	37.92	9.48	.57	1.14	.28
-Between the canyon and the slope	910	2.0	1,820	.40	.80	.20	2.68	5.36	1.34	.08	.16	.04
TOTAL SHELF N. 33°N				5.26	10.52	2.65	35.25	70.48	17.62	1.05	2.11	.53

ECONOMIC AND SOCIAL IMPACTS

In this chapter, the potential impacts on Long Island of leasing Atlantic Outer Continental Shelf acreage for hydrocarbon exploration are evaluated. Potential hydrocarbon reserves and their associated production costs were estimated in the previous chapter for that portion of the AOCS acreage which could have potential economic impacts on Long Island. These estimates will be used here in determining the probable magnitude of such impacts.

Development of offshore hydrocarbon resources proceeds in six general stages. These steps pertain to each lease sale and the specific tracts encompassed by the sale. They include:

1. Geophysical exploration,
2. Exploratory drilling,
3. Field development,
4. Hydrocarbon production,
5. Transportation and storage, and
6. Processing (Council on Environmental Quality, 1974, p. 4-1).

Of course, not all of the development stages are undertaken for a specific leasehold if exploratory activity determines an absence of commercial hydrocarbon deposits. Consequently, the potential effects of AOCS activity on Long Island will vary with the stage of leasehold development, the extent to which development proceeds, the technical and economic factors associated with the development of a given set of leaseholds, and the timing and location of lease sales. Each development stage, relating to a specific leasehold and in concert with the development activity taking place on all leaseholds, can have potential impacts for Long Island as well as other geographical areas within the United States. These impacts can either be positive or negative and, depending upon one's point of view, may be interpreted differently by individuals residing in the same region.

The remainder of this chapter will attempt to identify the more important potential impacts to Long Island of AOCS development. In so doing, we make no pretense of exhausting the possible implications which may accrue due to the leasing of federal lands in this area. However, we will attempt to utilize the various OCS development stages as a guide through which the more important potential impacts can be discerned. In each of these cases, a more substantial evaluation will be undertaken.

The OCS Development Process: To enable a better understanding of the differential effects caused by each of the six development stages, a brief description of the process will be provided. Geophysical exploration includes measurements of magnetic and gravity fields, seismic analysis, bottom sampling, and bottom coring (Council on Environmental Quality, 1974, p. 4-1). Geophysical exploration alone has a minimal effect on the onshore regions surrounding the activity. Historical experience indicates no permanent environmental damage would result from this type of activity. Since specialized crews and equipment are needed, it is unlikely that additional employment would be generated from onshore regions close to new wildcat exploration areas. Field crews are small and data processing normally takes place onshore at established facilities of private sector firms. When extensive activity of this nature takes place in a given area, a base of operations may need to be established on a temporary basis. In such cases, small amounts of additional income may be generated for the region surrounding the temporary base of operations. Studies in the Gulf of Mexico indicate that reconnaissance and detailed seismographic exploration can be carried out for a given tract at a cost of less than $150,000 (U. S. Department of the Interior, Offshore Petroleum Studies, 1972, pp. 10-11). That figure is for the total contract cost to the firms involved and assumes water depths of 100 feet and distances from shore of 50 miles. This type of activity normally takes place prior to a lease sale and is usually carried out by a consortium of companies who plan on participating in the bidding process. Given the small amounts of manpower and dollars involved, it is likely that any such activity in the AOCS would have a minimal effect on Long Island. This is particularly true in view of the fact that the most likely temporary base of operations would be in the New York City harbor area.

The only way to determine accurately if commercial quantities of oil or natural gas exist under the ocean floor is through exploratory drilling. This activity is normally carried out from a drill ship or a semisubmersible drilling rig. It is during exploratory drilling that the possibility of well blowouts resulting in hydrocarbon spills is the greatest. A blowout is caused when a sudden increase in pressure in the hole being drilled results in loss of control of the well and release of large quantities of oil or natural gas into the ocean waters (Council on Environmental Quality, 1974, p. 4-4). Hence, the environmental risks of a spill are greatest during the exploration phase. On the other hand, potential impacts on regional income and employment are also greater in this phase of development than they were for geophysical exploration. Given our estimates in the previous chapter, it appears that exploratory drilling for a given reservoir could cost $34 to $44 million or about $4 to $5 million per exploratory well drilled. Moreover, it is generally assumed that the average exploratory drilling rig in service requires 175 workers; from 50 to 70 of whom would be stationed on the rig at any one time with a seven day on-seven day off rotation. Remaining workers would staff onshore transportation and support operations (Resource Planning Associates, Inc. and David M. Dornbusch and Company, 1973, pp. I-6, I-7). Onshore activities associated with exploratory drilling would probably occur at or near a port facilitiy or other transshipment point. Assuming a three to five year lag between acreage leasing and hydrocarbon production, one could expect most exploratory drilling activity to be completed on a newly leased area within three years. Consequently, for the Long Island impact area, exploration activities would begin in 1976 and continue at least through 1985. The major activity in the Baltimore Canyon portion of the impact area would continue through 1980 given the assumptions developed in the previous chapter. The economic impact, other than environmentally related impacts, during this phase of development would depend largely upon whether airports and/or ocean ports on Long Island were used as support and transshipment points for drilling activity.

If commercial deposits of oil or natural gas are located, field development is initiated. Additional exploratory wells are drilled to further delineate the field and semipermanent platforms are constructed for hydrocarbon production. Development wells are drilled and processing-transportation facilities established from these platforms (Council on Environmental Quality, 1974, p. 4-7). When platforms are used, a number of wells (up to 40 on large platforms) can be completed from a single platform using directional drilling techniques. Blowout risk is lower for development wells than for exploratory wells since the geologic structure is better known (Council on Environmental Quality, 1974, p. 4-14). However, spills may occur or other contaminants, such as drilling mud, may be released into the ocean at the drill site. The economic impact due to the development phase is potentially the largest of the various stages. Over $120 million of investment cost may need to be committed in the development of a single reservoir (for the Long Island impact area). The extent to which employment and incomes on Long Island would be affected depends upon the location of supply and material facilities, transshipment points, and the indirect impacts of direct supply. These factors will be discussed in greater detail below.

Once production has begun, the oil and/or natural gas must be transported to processing and distribution points on shore. Most often, pipelines are used for this purpose, rather than tankers, except for the early periods of petroleum production in a new field. Only when small isolated deposits or deposits extremely far from the shoreline are discovered, would it be economic to transport hydrocarbon production through modes other than pipeline. Although laying pipe through coastal wetlands can result in serious degradation to the environment, transporting offshore production through such a mode is probably environmentally safer than other means (Council on Environmental Quality, 1974). Pipeline investment costs may be as high as 25 percent of the total reservoir development costs cited previously. Their exact locations, however, will depend on both the location of discovered hydrocarbon deposits and that of the appropriate onshore processing and transshipment facilities.

The last phase of hydrocarbon development includes petroleum refining and natural gas distribution (usually after minimal processing). Major environmental, social and economic impacts could be expected in the general area of a refinery complex. On the other hand, minor implications would appear to stem from transshipping natural gas. These implications will be discussed in more detail below.

Techniques of Regional Analysis: On the basis of the brief description given in the previous section, it appears that the major onshore implications of developing and producing discovered hydrocarbon deposits on the Atlantic Outer Continental Shelf will stem from the exploratory, development and processing stages. From the standpoint of both increases in regional activity (employment and income) and potential environmental damages causing a reduction in such activity, these three stages will be most important. The question which must now be asked is: By what means should such potential impacts be estimated in view of the surrounding geologic uncertainty and imperfect knowledge of onshore economic linkages?

Perloff has pointed out that measures of regional change can encompass concepts of both "volume" and "welfare" (Perloff, 1963). For example, total sales, income and employment in a region as well as per capita real income, its changes and stability may be important in judging the effects of a given exogenous change. What needs to be noted is that a linear relationship does not necessarily exist between those measures associated with volume and those related to welfare. Obviously, however, use of per capita measures would provide a relative gauge among alternatives and would, thus, be a better indicator of regional change both within a region and between regions of various physical and economic sizes. The latter is especially important since regional size will influence the absolute size of any onshore effects. In any case, regional per capita income effects can be determined from total impacts and, therefore, the measurement methodology discussed below will concentrate on the absolute effects that can be forecast.

Such an analysis can logically be separated into two components. First, the direct impacts which accrue to the region must be measured. Such a measurement should consider the overall investment and operating expenses required to develop that portion of the Atlantic Outer Continental Shelf which can have an economic impact on Long Island. However, of that total (taking into consideration the element of time), appropriate consideration must be _iven only to that portion which accrues to the region. In essence, sales by the region to facilitate AOCS development can be treated as an export from the area. Environmental damages will also have a direct impact and can be considered like an import for economic analysis.

The second component is the so-called multiplier or expansion effect of an initial or direct impact. It is dependent upon the first and is normally considered a regional transfer. That is, no national gain is involved, only a change in the location of economic activity. In effect, the multiplier impact refers to the round-by-round respending effects of the initial action.

Care must be taken in the quantification of both the direct and indirect effects of leasing activity in the Atlantic Outer Continental Shelf. Standard techniques can lead to the measurement of artificial regional changes. This stems from our definition of regional growth and the assumption made concerning regional employment. If full employment is projected for the region over the lifetime of offshore activity, onshore impacts can result in a labor inflow to the region with no necessary improvement in regional per capita incomes. On the other hand, if full employment is not forecast or if slack (underemployment) exists in the regional labor markets, direct and multiplier impacts can result in real changes in regional per capita incomes. Also, a redistribution of labor resources toward higher valued occupations because of the offshore activity could result in improvement in the average per capita income regardless of the rate of unemployment. Thus, if per capita rather than total regional income is important, the assumptions the analyst makes on these issues is critical to the evaluation results. Most empirical situations would tend to present a mix of conditions, over time, rather than one of the polar cases outlined above. Little research exists to resolve this problem. We will initially proceed by ignoring the population inflow question. If this turns out to be an important issue, we can return to it at a later point.

The incidence on Long Island of offshore development expenditures depends, as indicated above, on the location of supply and processing points. On the other hand, the indirect or multiplier effects of such activity depend upon the extent and degree of economic linkages within the regional economy. Various techniques have been developed to measure such linkages. The three most commonly used are: (1) economic base analysis; (2) regional input-output analysis; and (3) econometric modeling. Each of these approaches will be discussed in detail below. Given the constraints surrounding this particular research effort, one approach, the economic base form of analysis, will be chosen to estimate the regional multiplier values (and, hence, the indirect impacts) for Long Island. First, however, we will consider the direct or first round impacts of AOCS leasing.

Direct Impacts: As indicated above, direct impacts of AOCS leasing on Long Island can take place during the development, production and processing phases of the lease activity. The development and production phases have a potential impact in proportion to a region's ability to supply factors of production at competitive prices. Due to spatial considerations, an obvious comparative advantage exists, *ceteris paribus*, for regions in close proximity to the area of activity. Development and production activity can also have negative impacts on a regional area through the mechanism of environmental damages. Reduced economic activity in existing sectors due to such damages must be weighed against any positive effects stemming from a region's ability to supply factor inputs. Finally, the processing component of hydrocarbon development could have potential impacts (both positive and negative) on the region where such activity is located. In the following sections, each of these aspects will be discussed in detail.

Factors of Production: In Chapter 2 we gave a rough forecast of the exploratory, development and operations costs of drilling for hydrocarbon deposits under various conditions in the Atlantic. When coupled with hypothetical leasing schedules and a model of bidding behavior whose objective function is to maximize after-tax net present value for the private sector, estimates of the various cost components for the Long Island impact area can be derived through time (Kalter *et al.*, 1974). Utilizing alternative assumptions with respect to hydrocarbon pooling in the Long Island impact area, this approach can provide us with the background information necessary to analyze potential onshore impacts. Tables 11 and 12 display that information for the two hydrocarbon pooling assumptions utilized in Chapter 2.

The values in Tables 11 and 12 are based upon an analysis of production costs for the Mid-Atlantic region. Using figures derived from National Petroleum Council (1974) data extrapolated to Mid-Atlantic conditions, the separate cost component percentages for oil and associated natural gas development are as follows:

exploration	18
production platform	30
development wells	20
pipeline	18
production and storage facilities	12
other	2

Table 11.--Hydrocarbon Production Costs, by Major Development Phase, for the Long Island Impact Area*

(Hydrocarbon Pooling Assumption No. 1)

Leasing Year No.	Exploration	Platform	Well development	Pipelines	Prod. fac. and Storage	Operating Cost	Total
1	26						26
2	40	21	14				75
3	8	120	52				180
4	6	79	58	44	22		209
5	73	38	30	92	65		298
6	73	121	57	32	8	19	310
7	69	225	127	93	48	20	582
8		196	146	135	89	28	594
9			49	88	85	42	264
10						54	54
11						54	54
12						54	54
13						54	54
14						54	54
15						54	54
16						54	54
17						54	54
18						54	54
19						54	54
20						53	53
21						49	49
22						45	45
23						46	46
24						35	35
25						34	34
26						34	34
27						25	25
28						16	16
29						16	16
30						11	11
31						5	5
32							
TOTAL	295	800	533	483	317	1018	3447

*All values in millions of 1974 dollars.

Table 12.--Hydrocarbon Production Costs, by Major Development Phase, for the Long Island Impact Area*
(Hydrocarbon Pooling Assumption No. 2)

Leasing Year No.	Explor-ation	Plat-form	Well Devel-opment	Pipe-line	Prod. fac. and Storage	Operating Cost	Total
1	69						69
2	71	54	36				161
3		246	117				363
4		96	87	81	46		310
5			24	158	110		292
6						34	34
7						34	34
8						34	34
9						34	34
10						34	34
11						34	34
12						34	34
13						34	34
14						34	34
15						34	34
16						34	34
17						34	34
18						34	34
19						34	34
20						35	35
21						29	29
22						19	19
23						19	19
TOTAL	140	396	264	239	156	578	1773

*All values in millions of 1974 dollars.

For non-associated gas and natural gas liquids, the same proportions as above were used except for exploration cost which was included in oil development. For example, 30/82 of the non-associate natural gas cost, or 36 percent, was attributed to platform cost.

The results shown are based upon the allocation of exploratory and development costs over an assumed development period. In the case of the first lease sale, that development period was assumed to be five years. The required time horizon was reduced to four years for the second year of lease sales and to three years thereafter. To determine the time stream of the cost components over all lease areas, the time phasing of each cost component over the development period was needed. A different time phasing was utilized for the 5, 4, and 3 year development periods. Exploration costs were allocated to the first year or two years depending upon the length of the development period. Platform and well development costs followed exploration expenses in the middle year(s), and pipeline and production facilities were allocated to the later years. The time streams for each cost component for both oil and natural gas were then combined for all lease years to produce the data in Tables 11 and 12. Operating costs for both oil and natural gas were also calculated for each lease year and combined for the Tables. This exercise was completed for both hydrocarbon pooling assumptions used in this analysis. Table 11 reflects reserves and development costs assuming the AOCS hydrocarbon resources are distributed according to the volume of sedimentary rock over all AOCS areas (Pooling Assumption No. 1). Table 12 reflects the alternative assumption (and associated costs) that reserves are concentrated in the Baltimore Canyon and Georges Bank areas according to the volume of sedimentary rock (Pooling Assumption No. 2). In both cases, the costs given are limited to potential hydrocarbon development within the Long Island impact area defined previously.

The cost component breakdown lacks sufficient disaggregation to be related to a Standard Industrial Classification taxonomy of onshore activity. The authors know of no appropriate breakdown in this regard with respect to offshore hydrocarbon development. The national input-output model for 1967 (the latest available) does, however detail the industrial source for the factors of production used by establishments engaged in crude oil, natural gas and natural gas liquids development. The direct requirements of such establishments are displayed in Table 13. That is, for each dollar of produced hydrocarbon sales during 1967, the values shown give the value of factor inputs required and the value added. The measures shown can only be used as an indication of potential onshore industries affected by leasing activity. They do not give a true representation of the economic establishments potentially impacted by OCS activity either regionally or nationally, for the following reasons:

1. The data base was established with 1967 inputs; therefore, it is not current with respect to relative prices, technology or trade patterns.

2. The values given pertain to both onshore and offshore activity by the industry during the stipulated year.

3. The values are a composite of all activity by the economic sector involved, including exploratory actions, development

Table 13.--Direct Requirements Per Dollar of Delivery to Final Demand (1967) for the Crude Petroleum and Natural Gas Sector*
(SIC 1311 and 1321)

Rank	Sector	Direct Requirement
1	Real Estate and Rental	.16161
2	Gross Imports of Goods and Services	.07159
3	Maintenance and Repair Construction	.03168
4	Crude Petroleum and Natural Gas	.02487
5	Business Services	.01609
6	Wholesale and Retail Trade	.01162
7	Electric, Gas, Water and Sanitary Services	.01145
8	Chemicals and Selected Chemical Products	.01090
9	Electric Industrial Equipment and Apparatus	.01075
10	Scrap, used and second hand goods	.00973
11	Transportation and Warehousing	.00971
12	Primary Iron and Steel Manufacturing	.00796
13	Finance and Insurance	.00618
14	Business Travel, Entertainment and Gifts	.00576
15	General Industrial Machinery and Equipment	.00570
16	Stone and Clay Products	.00552
17	Machine Shop Products	.00532
18	Other Fabricated Metal Products	.00416
19	Construction, Mining and Oil Field Machinery	.00381
20	Engines and Turbines	.00323
21	Heating, Plumbing and Structural Metal Products	.00322
22	Rubber and Miscellaneous Plastics Products	.00227

Table 13.--continued

Rank	Sector		Direct Requirement
23	Petroleum Refining and Related Industries		.00220
24	Automobile Repair and Services		.00114
25	Communications; Except Radio and TV Broadcasting		.00082
26	Scientific and Controlling Instruments		.00062
27	Paints and Allied Products		.00059
28	Federal Government Enterprises		.00042
29	Office Supplies		.00041
30	Medical, Educational Services and Nonprofit Organizations		.00038
31	Radio, Television and Communication Equipment		.00033
32	Miscellaneous Textile Goods and Floor Coverings		.00032
32	Metalworking Machinery and Equipment		.00032
34	Electric Lighting and Wiring Equipment		.00017
35	Electronic Components and Accessories		.00011
36	Paper and Allied Products, Except Containers		.00006
37	Printing and Publishing		.00004
38	Coal Mining		.00002
38	Miscellaneous Manufacturing		.00002
40	Paperboard Containers and Boxes		.00001
40	Miscellaneous Electrical Machinery, Equipment and Supplies		.00001
	Value Added		.57287
	Employee Comp.	.05865	
	Indirect Business Tax	.04892	
	Property-Type Income	.46530	

*Source: "The Input-Output Structure of the U. S. Economy: 1967," Survey of Current Business, February 1974.

of resource deposits, and their production. Consequently, the use of the values given would have to be predicated upon a similar mix of actions in the year being forecast. Not only is such a mix unlikely to occur in subsequent years, but even if it did, the values would be inappropriate for our use. That is, we ideally would like to have the factors of production broken out for each of the major components of the industry's activity (exploration, development, production and transportation).

4. The values given refer to the total requirements of the development-production process rather than to those furnished by a specific region. For our purposes, a regional breakdown or a mechanism by which such a breakdown could be made would be preferred.

Lacking detailed data with regard to the above points, however, the national input-output data does give some indication of sectors which could be affected by OCS activity. In addition, data on the location quotient (see Table 14) for each industrial sector on the Island can add information on potential exporting sectors. The location quotient can show, for a given economic sector within a region, whether the export component is less than, equal to or in excess of the national average for that sector. For example, if the sand and gravel sector of Long Island is six percent of the region's total employment and if three percent of the national work force is engaged in this sector, then the location quotient would be 2 for the Island. Assuming that all other factors for the region are similar to that of the nation (i.e., production, income, and consumption), a location quotient greater than 1 implies that the sector in question engages in export activity.[4] Used in conjunction with other sources, such as the results given in Chapter 2, the information shown can permit some judgments to be made about potential effects on Long Island of activity within the defined impact zone. It is to this specific question that we now turn.

---

[4]For empirical purposes, the location quotient can be specified as:

$$LQ = \frac{S_i/N_i}{S/N}$$

where S_i equals the number of wage earners in industry i for a given region, S equals the number of wage earners in all industries in the same region, N_i equals the number of wage earners in industry i in the United States, and N equals the number of wage earners in all industries in the United States.

Table 14.--Nassau-Suffolk Industrial Sector Specialization Relative to the U.S.*
(1972)

Rank	Sector	Location Quotient
1	Electrical Equipment and Supplies	1.95
2	Amusement and Recreation Services	1.74
3	Fisheries	1.73
4	Local and Interurban Passenger Transit	1.73
5	Food Stores	1.73
6	Agricultural Services and Hunting	1.65
7	Miscellaneous Business Services	1.62
8	Instruments and Related Products	1.59
9	Furniture and Home Furnishings Stores	1.59
10	Miscellaneous Repair Services	1.56
11	General Merchandise	1.53
12	Transportation Equipment	1.52
13	Apparel and Accessory Stores	1.49
14	Educational Services	1.42
15	Special Trade Contractors	1.40
15	Insurance Agents, Brokers and Services	1.40
17	Electric, Gas and Sanitary Service	1.39
18	Motion Pictures	1.36
18	Miscellaneous Services	1.36
20	Auto Repair, Services and Garages	1.25
21	Miscellaneous Manufacturing Industries	1.22
22	Chemicals and Allied Products	1.21

Table 14.--continued

Rank	Sector	Location Quotient
23	Combined Real Estate, Insurance, Etc.	1.20
24	Medical and Other Health Services	1.18
25	Communication	1.11
25	Wholesale Trade	1.11
25	Eating and Drinking Places	1.11
26	Banking	1.10
27	Building Materials and Farm Equipment	1.09
28	Transportation Services	1.04
28	Legal Services	1.04
30	Real Estate	1.02
31	Insurance Carriers	.98
32	Automotive Dealers and Service Stations	.96
33	Credit Agencies Other Than Banks	.92
34	Heavy Construction Contractors	.87
35	Fabricated Metal Products	.86
36	Nonprofit Membership Organizations	.83
37	General Building Contractors	.81
38	Apparel and Other Textile Products	.76
38	Rubber and Plastic Products	.76
40	Ordnance and Accessories	.73
41	Trucking and Warehousing	.67
42	Lumber and Wood Products	.64
43	Furniture and Fixtures	.60

Table 14.--continued

Rank	Sector	Location Quotient
43	Paper and Allied Products	.60
43	Printing and Publishing	.60
44	Security, Commodity Brokers and Services	.56
45	Personal Services	.52
46	Transportation by Air	.50
47	Water Transportation	.47
48	Holding and Other Investment Companies	.37
48	Hotels and Other Lodging Places	.37
48	Textile Mill Products	.37
51	Stone, Clay, and Glass Products	.34
52	Machinery, Except Electrical	.24
53	Nonmetalic Minerals, Except Fuels	.23
54	Food and Kindred Products	.19

*Source: County Business Patterns 1972, (Washington: GPO), 1973.

As indicated by a recent Department of the Interior memorandum:

> Many of the industries and services required by the oil and gas industry for OCS development are already located in the Mid-Atlantic. Such industries are marine supply and repairs, general machine repair, welding shops, warehousing and storage, freight handling, and trucking and rail service. They are readily available and will be utilized. Other services such as drilling services, catering to rig and platform crews, and drilling tool, mud, and chemical supplies are more specialized. Since specialized industries are highly developed in the Gulf of Mexico region, it is expected, that at least initially, they will export products and services directly from the Gulf region. They can be expected to utilize some storage facilities, occasionally dock ships in the Atlantic coast, and in some cases, establish small office bases in the Mid-Atlantic region to direct operations.
>
> In all phases of OCS development, port facilities will be utilized. Because of the size and draft of drilling ships, semi-submersible rigs and supply vessels handling heavy equipment, major port facilities will be needed. Because of the location of the sale, the Port of New York and New Jersey and/or the Port of Philadelphia may be utilized for these purposes. Those industries and services needing a location close to such ports, such as warehousing and storage, and machine repair and supplies, may be expected to be provided from one or both of these areas. Jack-up rigs and smaller supply vessels might be serviced from smaller ports.

A recent study prepared by the U. S. Army Corps of Engineers (1972) points out that no major port facilities currently exist nor is there future potential for such facilities in the Long Island area. The closest port available to service and supply large scale operations in the Long Island impact area of the AOCS would be the Port of New York. Consequently, location of warehousing services, supply depots, associated support facilities and the necessary manpower to operate such facilities is unlikely to have a major impact on the Nassau-Suffolk County region. Implications for the New York City area, proper, may, however, be substantial.

In addition, no ship building yards currently exist in the Long Island region. The nearest ship building facility is at the old Brooklyn Navy Yard. Although the commercial operations now conducting business at that location have developed a skilled labor force, it is primarily drawn from the resident labor force immediately surrounding the facility location. Moreover, the facility is not currently equipped to undertake construction of either semi-submersible drilling rigs or production platforms. Because of the specialized nature of such activity, it is likely that no rig or platform fabrication would be undertaken on the east coast for at least the first five to ten years of OCS development. Existing shipyards are not equipped to handle such activity and the increased cost associated with this type of fabrication would far outweigh transportation costs of platforms and rigs from existing yards in the Gulf States area. Assuming adequate capacity in these southern locations, the economic incentive for developing east coast production facilities does not appear to be substantial. In view of the fact that leasing in the Gulf Coast area will be tapering off as available acreage with quality prospects diminishes and given the current forecasts of the AOCS potential reserves, sufficient capacity will probably be available in existing Gulf Coast shipyards for this type of construction during the time period assumed for AOCS development.

In view of the above discussion, it appears that exploration and platform installation activity will have little economic impact on the Long Island area. Use of Long Island facilities as a transshipment point for the manpower employed on drilling rigs and platforms appears to be the most likely possibility for consideration. Given the location of the Long Island impact area vis-a-vis airport facilities in Nassau-Suffolk County, the study area could provide a base of operations for that portion of the OCS activity requiring transportation and support of the offshore labor force. In the Gulf of Mexico situation, aircraft (helicopter) operations have been the primary mechanisms used for transporting such manpower between shore facilities and rig or platform locations. In addition, small and lightweight supplies are often transported by this mode. On the other hand, as the recent Department of the Interior memorandum points out:

> In general, many crew members of drilling rigs and platforms are specialized and highly mobile, so that those persons employed on the rigs and platforms would not necessarily be drawn from the regional labor force or moved into the area.

Moreover, the manpower requirements do not appear to be substantial. Based upon Council on Environmental Quality data (1974) the Department of the Interior has tentatively estimated that only 500 workers would be required to support exploratory drilling rigs and ships in the Baltimore Canyon area through 1985 due to the first three million acre lease sale. In addition, assuming approximately 90 persons are needed to man each installed platform, the Department has estimated that between 2700 and 4500 persons would be required during the production phase for the Mid-Atlantic region.

These values may be compared with those derived by the Gulf South Research Institute (1973). In a study conducted in the Gulf of Mexico area, with results extrapolated to possible Atlantic OCS activity, they found that a total employment increase of 20,900 would be associated with an oil production rate of 500,000 barrels per day. A third study conducted at the Massachusetts Institute of Technology (Ahren, 1973) estimated total employment to be 3,724 in the Georges Bank area at a production rate of 500,000 barrels per day. Commenting on the difficulty of utilizing these data sources, the National Ocean Policy Study said:

> It is very difficult to analyse the data, because one does not exactly know which activities are included in each of the studies, or how data were obtained. Moreover, extrapolating data for one region from data obtained in another area where circumstances surrounding oil and gas development may be quite different, is likely to create built-in biases and inaccuracies (U. S. Congress, Senate, Nov. 1974).

However, we may get some idea what an upper limit on employment effects might be by using the 20,900 employment figure associated with 500,000 barrels per day of production. If we assume that employment effects are proportional to production and that the peak daily production in the Long Island impact area would be 150,000 barrels per day, the maximum total employment effect would be 6,300 which is less than one percent of total Long Island employment as of June, 1971 (Kamer, p. 2).

The well development phase of OCS activity is similar to the exploratory and platform development phases. Major dependence for movement of materials and supplies would concentrate on existing port areas. Manpower requirements, on the other hand, could utilize other facilities as a base of operations. The impact of the pipeline installation and production facility and storage phases of development will depend primarily on the location of processing facilities, port operations, and hydrocarbon deposits. As we will indicate in a subsequent section, refinery capacity related to AOCS development is unlikely to be placed in the Long Island region. Given the potential location of such facilities in the New Jersey-Pennsylvania-Maryland area and the location of the Ports of New York and Philadelphia, impacts of this activity on Long Island are assumed to be negligible. As indicated by the region's location quotients, Long Island does not appear to have major product exporting capacity in economic sectors that would be related to such activity (steel fabrication, construction, or machinery products). Moreover, the manpower requirements related to such activities would undoubtedly be based in the area immediately surrounding any temporary base of operations. Since offshore pipeline laying operations and construction of production and storage facilities are highly specialized activities, it is likely that nonregional firms would be engaged to undertake this activity.

Finally, the costs of the operating phase for discovered OCS reservoirs need to be considered. Recent studies in the Gulf of Mexico (U. S. Department of the Interior, 1972) indicate that of the direct (labor, transportation, equipment maintenance, operating supplies, work over expense, and radio-telephone expense), indirect and fixed costs involved, less than 13 percent is attributed to factors which might affect Long Island. These factors include the labor, overhead, food expense, and labor transportation components. Given the nature of operating expenses, it would be expected that only a portion of these could ultimately affect Long Island. For example, it is generally known that food service in the Gulf of Mexico is provided through port facilities and not by air transportation. Other operating costs would also have a high probability of entering local economies through major ports which would serve as operation bases or through the areas containing refinery and processing facilities.

In view of the above discussion, it appears that the portion of production costs attributable to pipelines, production facilities and storage facilities which would have a <u>direct</u> impact on the Nassau-Suffolk County region would be negligible. With respect to exploration activity, platform development, well development, and operating expenses, the potential impacts relate largely to the possible establishment of bases of operation servicing offshore manpower requirements and furnishing supplies for which the region may have a comparative advantage. The gross impacts of such activity would probably not exceed ten percent of the total costs involved. Although this estimate must, by necessity, be subjectively derived, a sufficient number of information sources have been reviewed to place a reasonably high level of confidence in it. The products expected to be supplied from regional industries would be those that do not require technical sophistication to produce. An example would be simple metal products. The expensive and complex equipment required for drilling and production (for example, drill bits and monitoring equipment) would probably be shipped into the area from locations where production currently exists. Table 15 summarizes the maximum potential direct effects on Long Island of AOCS development within the impact area. The values shown represent ten percent of the exploration, platform, well development and operating costs for each year of field life under the two hydrocarbon pooling assumptions used for this study. It should be noted that these values refer to regional sales and not to a net change in regional income.

Oil Spill Impacts: This section provides an overview of the process involved in determining the economic impacts on recreation and fishing in the Long Island area from potential AOCS oil spills. As will be seen below, no quantitative estimates of future economic loss can reasonably be provided. The appropriate analytical process is described, and examples of the necessary calculations are supplied, but certain critical links between estimates of the recoverable hydrocarbon resource and the magnitude of economic losses in recreation and fishing cannot be reliably established. These crucial links and missing data will be identified in the course of outlining the analytical framework.

Background material and much of the available statistical data is taken from the spill impact work of Devanney and Stewart (Devanney and Stewart, February 1974; Devanney and Stewart, November 1974; Lahman et al.; Stewart et al.; Devanney and Stewart, April 1974). No effort will be undertaken to comprehensively summarize the results of their work. Rather, the analysis is aimed at applying their findings to a process for determining the magnitude of potential economic impacts. Also, no analysis of biological or environmental impacts per se (except as they affect recreation and fishing) will be undertaken. Readers are referred to the Massachusetts Institute of Technology and Council on Environmental Quality reports in this regard (Schrader et al.; Council on Environmental Quality, 1974).

To estimate the magnitude of potential economic losses due to oil spills, a number of factors must be considered. The analysis proceeds in three general stages depicted in Figure 2. To complete this analysis, data and/or assumptions for the following variables and parameters are required:

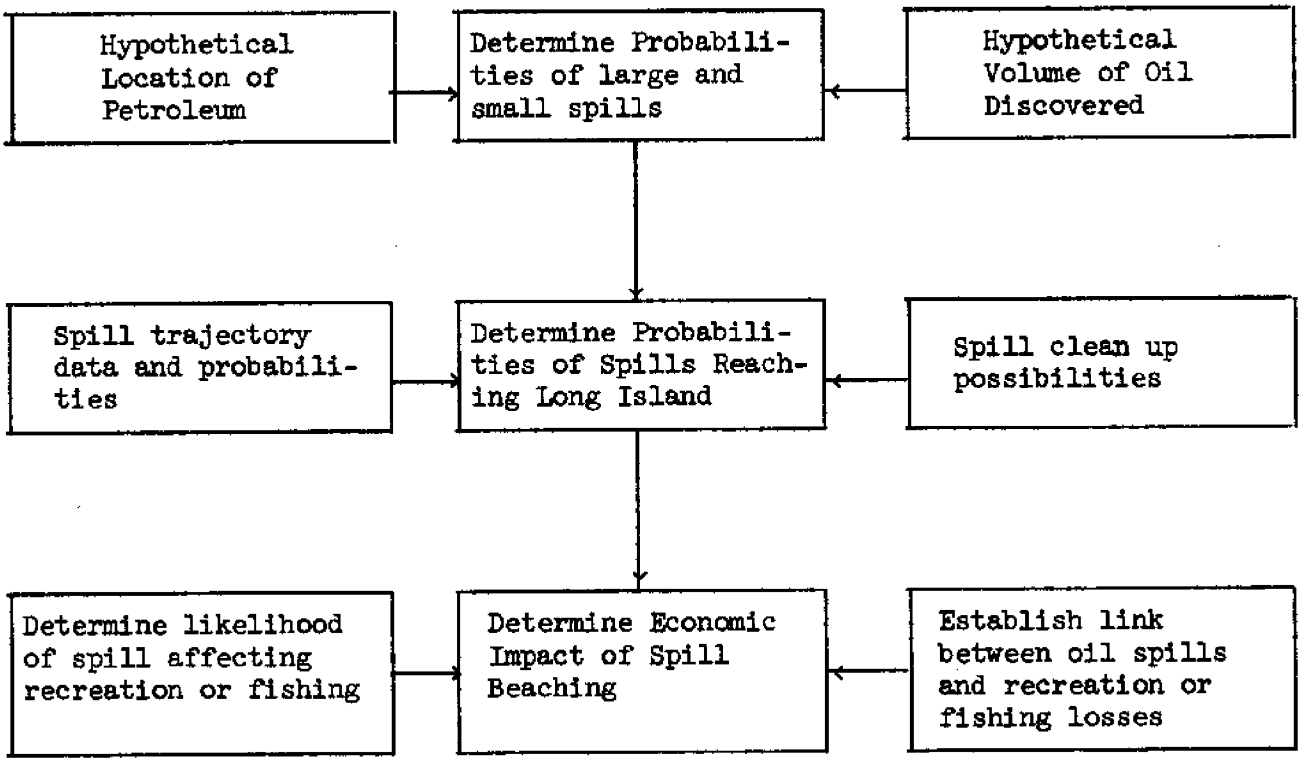
- volume of oil produced during the field lifetime,
- distance from Long Island of production platforms,
- probability and numbers of large spills (greater than 42,000 bbls.),
- probability and numbers of small spills (less than 42,000 bbls),

Table 15.--Maximum Potential Impact (Sales) of Hydrocarbon Production Costs for the Long Island Impact Area*

Leasing Year No.	Pooling Assumption No. 1			Pooling Assumption No. 2		
	Investment	Operating	Total	Investment	Operating	Total
1	2.6	---	2.6	6.9	---	6.9
2	7.5	---	7.5	16.1	---	16.1
3	18.0	---	18.0	36.3	---	36.3
4	14.3	---	14.3	18.3	---	18.3
5	14.1	---	14.1	2.4	---	2.4
6	25.1	1.9	27.0	---	3.4	3.4
7	42.1	2.0	44.1	---	3.4	3.4
8	34.2	2.8	37.0	---	3.4	3.4
9	4.9	4.2	9.1	---	3.4	3.4
10	---	5.4	5.4	---	3.4	3.4
11	---	5.4	5.4	---	3.4	3.4
12	---	5.4	5.4	---	3.4	3.4
13	---	5.4	5.4	---	3.4	3.4
14	---	5.4	5.4	---	3.4	3.4
15	---	5.4	5.4	---	3.4	3.4
16	---	5.4	5.4	---	3.4	3.4
17	---	5.4	5.4	---	3.4	3.4
18	---	5.4	5.4	---	3.4	3.4
19	---	5.4	5.4	---	3.4	3.4
20	---	5.3	5.3	---	3.5	3.5
21	---	4.9	4.9	---	2.9	2.9
22	---	4.5	4.5	---	1.9	1.9
23	---	4.6	4.6	---	1.9	1.9
24	---	3.5	3.5			
25	---	3.4	3.4			
26	---	3.4	3.4			
27	---	2.5	2.5			
28	---	1.6	1.6			
29	---	1.6	1.6			
30	---	1.1	1.1			
31	---	.5	.5			
32						
TOTAL	162.8	101.8	264.6	80.0	57.8	137.8

*All values in millions of 1974 dollars.

Figure 2.--Analytical Process for Determining the Economic Impacts of OCS Oil Spills



-mean spill size for each group,

-time to shore (minimum and average),

-probability of spill reaching shore on Long Island,

-probability of spill beaching in areas of significant economic importance (i.e., major recreation areas),

-likely areal extent of beach that would be affected by a spill,

-time required (and cost) to clean up or weather a spill that has beached,

-information on how spill beaching probabilities would be affected by ocean clean up attempts, and

-information on how spill probabilities would be affected by new OCS production technology and regulations.

In addition, other assumptions are necessary in selecting data deemed most appropriate for the analysis from the range of possible inputs.

The Devanney-Stewart analysis of oil spill statistics assumes that the exposure variable determining the number and size of spills is the total volume of oil handled (Devanney and Stewart, April 1974, p. 26). The median reserve estimates for the two alternative pooling assumptions used in this analysis result in oil and natural gas liquids production of .88 and .46 billion barrels. Oil spill statistics in the Devanney-Stewart analysis are presented in terms of a small, medium, and large find corresponding to exposure levels of 122, 567, and 2,044 million barrels respectively (Devanney and Stewart, April 1974, p. 49). For purposes of projecting spills in this analysis, it will be assumed that the second pooling assumption (hydrocarbon resources concentrated in the most promising areas) results in a medium find in the northern end of Baltimore Canyon approximately in a location corresponding to CEQ drilling site 5 (EDS 5). For the other reserve pooling assumption it will be assumed that in addition to the medium find at EDS 5, two small finds are also located in the Long Island impact area.

There exists no strong support for these assumptions. However, given the reserve estimates from the two assumed hydrocarbon pooling assumptions, it is clear that the above delineation is quite reasonable. The geologic structure at a point about 60 miles south of Long Island and 60 miles east of New Jersey represents one of the more promising areas on the AOCS. Hence, it is reasonable to assume that a medium find could be realized in this area. This assumption is equally valid for either pooling alternative. Furthermore, the remaining area in the Long Island impact area (north of 40°N and east and southeast of Long Island) is not nearly so promising geologically. If petroleum is assumed to be located in this area, it is reasonable to assume that the field sizes will be rather small.

To sum up, by a series of geologic assumptions and through incorporating results from our OCS leasing model, we have derived two sets of production assumptions for the Long Island impact area. With these estimates in hand, we then went to the Devanney-Stewart work on oil spill statistics, and found that the "exposure" in terms of oil production inherent in these estimates was roughly compatible with their analytic breakdown in terms of field size. Our concentrated pooling assumption roughly translated into one medium find in the southern part of the Long Island impact area (northern Baltimore Canyon) with exposure of about .5 billion barrels. The dispersed pooling assumption translated into the same medium find plus two small finds somewhere in the region east and southeast of Long Island (north of 40°N). The next steps in the analysis are to determine the probabilities of oil spills occurring from these hypothetical finds, estimate the probability that a spill would beach on Long Island given that the spill occurs, and combine these probabilities to determine the likelihood of a spill beaching on Long Island assuming the hypothetical oil finds are actually realized.

Before taking these steps, however, it may be useful to digress for a moment to elaborate on the reasons for the impact area boundaries. Recall that the impact area was defined by considering both potential economic and environmental impacts. One check on the defined area would be to determine i' here are points outside the area which are likely to have a detrimental or positive effect on Long Island. For example, if there are points outside he area from which spills are likely to beach on Long Island, then the area should be expanded.

To perform this test, we need a conceptual framework to structure the problem. Let us assume that the likelihood of a spill beaching on Long Island is a 'unct'on of the probabilities of four events: (1) the probability of finding commercial quantities of oil, (2) given that commercial quantities of oil are found, the probabilities that spills will occur during the exploration or pro uction phases of development, (3) given that spills do occur, the pro'abilitie' that they will beach on Long Island with no ocean clean up, and (4) given all the above, the likelihood that ocean clean up would be attempte' and succeed. To be more precise, we will define the probability of each of these events using simple set notation:

$P(A)$ = probability of a commercial oil find of a given size

$P(A_1)$ = probability of a small find

$P(A_2)$ = probability of a medium find

$P(A_3)$ = probability of a large find

$P(B|A)$ = probability that one or mor' spills will occur given that oil is found in certain quantities

$P(C|A \cap B)$ = probability of a spill beaching on Long Island with no ocean clean up given that A and B occur

$P(D|A \cap B \cap C)$ = probability of the <u>failure</u> of ocean clean up given that A, B and C occur

$P(A \cap B \cap C \cap D)$ = probability that a spill will beach on Long Island (the intersection of the sets A, B, C and D)

That the last definition is correct may be seen by expanding a simple definition of conditional probability. The conditional probability of an ev-nt B, given that A occurs, is written $P(A|B)$ and is defined as follows:

$$P(B|A) = \frac{P(A \cap B)}{P(A)}$$

Multiplying both sides by $P(A)$, we get:

$$P(A \cap B) = P(A) \cdot P(B|A)$$

Thus, the probability of both A and B occurring (A intersection B) is the product of the probability of A occurring and the conditional probability of B given that A occurs (Mosteller, p. 133). This definition may be expanded to include all four events:

$$P(A \cap B \cap C \cap D) = P(A) \cdot P(B|A) \cdot P(C|A \cap B) \cdot P(D|A \cap B \cap C)$$

Of course, to get all the way to economic impacts, we would have to add additional ingredients such as the probability that the spill would beach on an economically important area such as a recreation center given that the spill beached on Long Island. However, this formulation will suffice for present purposes.

We now proceed to estimating the probability of spills from outside the impact area beaching on Long Island. Fortunately, two of the four required probabilities have been estimated in the work of Devanney and Stewart. Little or no work has been done estimating the other two probabilities. However, we can use a set of hypothetical probabilities to derive one estimate of the probability of spills outside the designated impact area beaching on Long Island.

Since no data are available on probabilities of finding oil on the AOCS, we are forced to select probabilities based solely on what little is known about the geology of the areas. The test will be performed for two sites outside the impact area: (1) the area south of the impact area (south of 39°30'N) in the Baltimore Canyon roughly corresponding to the location of drilling sites 6 and 7 in the Council on Environmental Quality study (Council on Environmental Quality, pp. 2-12); and (2) the area just east of the impact area (east of 70°20'W) and south of Nantucket. The first area is much more promising geologically and, hence, the probability of oil finds should be higher. Table 16 provides a set of probabilities for each potential drilling area. It must be recognized that these probabilities are hypothetical, and may differ significantly from actual conditions.

Table 16.--Hypothetical Probabilities of Petroleum Discovery at Two Sites Outside the Long Island Impact Area

	Baltimore Canyon (1)	East of Long Island (2)
no find	.4	.6
small find	.4	.3
medium find	.15	.1
large find	.05	.0

Based on an analysis of past spills, Devanney and Stewart determined probabilities of large platform and pipeline spills (greater than 42,000 bbls.) for each size field. These probabilities are given in Table 17 (Devanney and Stewart, April 1974, pp. 89-96). For pipeline spills, two estimates were presented by Devanney and Stewart. We will use the mean of their two estimates. The probability of small spills is ignored here under the assumption that ocean clean up procedures would prevent beaching, and/or that any damage would be negligible.

Table 17.--Probabilities for Large Platform or Pipeline Spills

	Field Size		
	small	medium	large
Platform:			
no spill	.75	.30	.03
1 or more spills	.25	.70	.97
Pipeline:			
no spill	.75-.85	.28-.48	.02-.10
1 or more spills	.25-.15	.72-.52	.98-.90

Turning to the third probability -- the probability that a spill would beach on Long Island given that oil is found and that spills occur -- we again use estimates from Devanney and Stewart. For the Baltimore Canyon area, the highest probability of a spill beaching on Long Island (in the spring season) is about .21 (for CEQ sites 6-7). In the summer, the probability drops to .02 (Council on Environmental Quality, p. 6-9). The minimum time to shore in spring is 61 days. Given the long time to shore, we estimate that the maximum chance of failure to clean up such a spill on the ocean would be about .4.

For the area east of Long Island, the highest probability of a spill beaching on Long Island is about .18 during the summer. Under the assumption of a 20 mile per hour sea breeze, this probability falls to a maximum of about .08, and during the winter falls to .01-.02. The minimum time to shore during the summer is 20 days and the average is 30 days (Devanney and Stewart, November 1974, pp. 16-29). With these times to shore a maximum chance of failure of ocean clean up is assumed to be .6.

We can now combine the expected values and assumed probabilities above to determine the likelihood of a spill outside the impact area beaching on

Long Island. We are interested in the sum of the probabilities of each of the joint occurrences. In set notation, we want:

$$\left\{ [P(A\cap B\cap C\cap D)]_{plt} \cup [P(A\cap B\cap C\cap D)]_{pip} \right\}_{small} \cup \left\{[P(A\cap B\cap C\cap D)]_{plt} \cup [P(A\cap B\cap C\cap D)]_{pip}\right\}_{med} \cup \left\{[P(A\cap B\cap C\cap D)]_{plt} \cup [P(A\cap B\cap C\cap D)]_{pip}\right\}_{large}$$

In other words, we are interested in the union of all the separate probabilities $P(A\cap B\cap C\cap D)$ which represent the intersection of probabilities of the four events. These results are given in Table 18.

Table 18.--Probability of Oil Spills Beaching on Long Island from Selected OCS Locations

Pool Size	Baltimore Canyon	East of Long Island
	platform+pipeline=total	platform+pipeline=total
small find	.006 + .005 = .011	.008 + .006 = .014
medium find	.007 + .006 = .013	.008 + .007 = .015
large find	.003 + .003 = .006	.000 + .000 = .000
TOTAL	.03	.03

As can be seen from Table 18, the maximum probability of a spill beaching on Long Island from either location outside the impact area is quite low -- 3 percent. Moreover, this probability is likely to be a maximum value for several reasons. First, the oil spill probabilities are for the entire life of the production systems (for all seasons), but the highest seasonal probability of a spill reaching shore was used in each case. If the lowest seasonal probabilities were used in each case, the combined probabilities would be reduced by a factor of 10 to .3 percent. Second, the technology of ocean clean up is rapidly advancing, and with the long times to shore for distant spills, the success rate for ocean clean up may be much higher than that assumed. Furthermore, the lowest spill probabilities are in winter when ocean clean up is most difficult, and the highest in spring and summer when ocean clean up chances are higher. Also, with the long times to shore, spill weathering would significantly reduce the damage should a spill actually come ashore. Third, the oil spill statistics were based on historical data and, hence, do not incorporate improvements in exploration and production technology aimed at reducing oil spills. Nor do the statistics take into account the many recent changes in offshore production regulations aimed at reducing the chances of spills.

Fourth, the probabilities of finding oil attached to each size find may be unduly optimistic. Admittedly, this analysis is rather crude and overly simplified, but given the paucity of good data, we believe the conclusions are acceptable. In summary, we have every reason to believe that the maximum chance of a spill reaching Long Island from outside the designated impact area is three percent, and we have strong justification for believing the chance to be much smaller, perhaps an order of magnitude smaller. Hence, our original impact area delineation stands.

Now, after that rather lengthy, but we hope useful, digression, we proceed along the path of examining the impacts of the two discovery scenarios within the Long Island impact zone described above. As we will see, the chances of a spill beaching on Long Island from parts of the impact area are rather high, perhaps intolerably high. Starting with the hypothetical medium find at CEQ drilling site 5 and using the same techniques as before, the maximum probability of a large spill reaching shore is about nine percent assuming a 70 percent chance of ocean clean up failure. If a small find were located 30 miles north of EDS 5 (15 miles south of Long Island), the probability of a spill beaching on Long Island jumps to 28 percent in the summer. In addition, the minimum time to shore drops to ten days (Devanney and Stewart, November 1974, p. 26). Hence, there is almost a one in three chance of a spill beaching on the Island.

From this point, we move to estimating the actual economic loss that could result from such spills. Unfortunately, however, the data will take us no further. Indeed, we have made a number of heroic assumptions to get this far. To move from an estimate of the probability that a spill will beach on Long Island to an estimate of economic losses requires information on which no reasonable basis exists even for making usable assumptions. Even if we are willing to use the assumption of one medium find and two small finds in the impact area, we must further assume locations for each find to estimate the probabilities of a spill beaching on the Island. Of course, as we have seen above, location is crucial in determining potential spill impact. Yet, at this point in time, we have absolutely no basis of selecting locations of petroleum deposits for the purposes of estimation. Furthermore, we have no basis on which to predict any of the following even given that we could accurately predict the probability of spills beaching:

- what proportion of spills would affect recreation or fishing areas as opposed to other areas,

- the areal extent of affected recreation areas,

- the length of time the spill area would be affected, and

- the extent to which a spill would deter recreational or fishing activity.

In other words, the proportion or amount of recreation or fishing activity that would be affected cannot be reliably determined. Physical data for the necessary links simply does not exist. Hence, we cannot, in good faith, generate estimates in which we have absolutely no confidence.

Let us summarize by briefly retracing our steps. First, we described the process that would be used in conducting this analysis if all the necessary data were available. We proceeded along the first steps by making assumptions on oil production ("exposure") and fitting these assumptions in the Devanney-Stewart framework. We then diverted to an elaboration of the impact area definition and used the diversion to derive and illustrate a process which is useful for estimating probabilities of spills beaching on Long Island. This process was then applied to sample drilling points within the impact area to illustrate the high potential for adverse environmental effects caused by spills resulting from oil drilling in parts of the impact area. The remaining steps and data requirements for the estimation of economic losses were identified but not undertaken because the results would be practically meaningless in the absence of better data. In the event that the required data does become available, the process can be completed and estimates of economic loss provided.

One final point, and a very important point indeed. This analysis has looked at the effects of offshore drilling and production on Long Island. In a sense, it has compared the conditions of Long Island <u>before</u> and <u>after</u> offshore leasing and production. However, the appropriate analytical procedure for evaluating such impacts is not a <u>before-after</u> analysis, but rather a comparison of the economic, social, and environmental situation <u>without</u> and <u>with</u> offshore drilling and production. This distinction is essential to this analysis. We wholeheartedly endorse the conclusion of Devanney and Stewart:

> Finally, it is extremely important to realize that the above estimates of probabilities do not represent the net effect of OCS development. The net effect will depend on what one assumes about the oil which would be landed in the absence of the development. For example, if one assumes the same amount of crude will be landed on the East Coast with or without a development, then according to our analysis there is a substantial probability that there will be as many large spills without the find as with the find. Such assumptions are outside the scope of the primary effects analysis, and we have not undertaken to estimate these <u>net</u> effects (April 1974, p. 124).

The important point here is that the case <u>without</u> AOCS leasing and production would also involve some of the same environmental and economic benefits and disbenefits (costs) we have evaluated in this analysis. Decisions on whether or not to proceed with AOCS leasing and production should be cast in this with-without framework rather than the before and after analysis conducted by both Devanney and Stewart and ourselves because of data limitations. Decision makers need to know the net effects of AOCS leasing and production as compared with whatever would be the most likely situation in the absence of AOCS leasing. We return to this important topic in Chapter 4.

Potential Refinery Impacts: The third major component of an offshore development process capable of producing major regional effects is the processing or refining aspect. The potential direct and indirect impacts from this activity are primarily dependent upon refinery locations. Thus, when reviewing possible implication of offshore leasing for Long Island, the specific question of refinery capacity and its location on the east coast must be considered. Processing facilities for natural gas production, on the other hand, are relatively small installations which are often located at central locations on offshore platforms. In any case, the employment and income impacts on a region would be almost inconsequential.

The issue of refinery location is a subset of the more general problem of industrial location. Assuming that firms seek to maximize profits, they will optimize the use of production factors so as to minimize costs at given levels of output in the short run and determine the appropriate scale of production for the long term. Obviously, facility location can be important in this process since it affects transportation costs, potential scale economies, and externality considerations. In general, firms attempting to minimize costs of production will take account of these factors when deciding on appropriate facility sites. Note, however, that it is not transportation costs alone which may affect the final decisions on such matters. Given a spatial location where transportation costs are minimized (considering both factors of production and final products), deviations to other locations may be appropriate on the basis of other factors (i.e., lower cost inputs, physical constraints, environmental restrictions, or scale economy questions). Historically, the relative importance of transportation costs for location selection has declined. As Isard (1972) has pointed out, agglomeration economies encompass many of the nontransportation cost factors involved. That is, scale economies within a given firm, economies due to location of other firms within the same industry within a single regional area, and urbanization economies due to the total economic interdependence caused by firms in all industries locating in a specific area. These influences along with market locations and the other factors mentioned above may result in a set of mixed signals for private sector decision makers. Some locations within broad regional areas may be ruled out because of inmutable constraints, while many others may be viable alternatives. Within the latter set, choices must be made given the private firm's objective function.

In applying this discussion to the potential location of refineries on the east coast, it is clear without detailed analysis that market factors are present which would justify refinery sites in the general region. Moreover, if refining activity were in response to Atlantic Outer Continental Shelf leasing activity, transportation cost factors would appear to dictate locations in reasonably close proximity to production rather than the added cost of shipping crude oil to refinery locations in distant regions and returning refined products to the east coast. Although environmental factors are often cited as a rationale for constraining such locations to areas other than the east coast, this no longer appears to be a valid argument given appropriate emissions standards and their enforcement by governmental agencies. In recent years, at least one new grass roots refinery has been constructed (in Bellingham, Washington) which meets and exceeds all current and proposed federal environmental air and water standards. Thus, from the standpoint of the broad east coast region, refinery locations appear justified. Accepting that assumption, the task of this analysis is to identify specific factors which might influence the choice of locations vis-a-vis Long Island.

First, it can be shown that transportation costs will be an important element in the determination of optimal refinery locations. Although the relative prices of other factor inputs may be important from an international standpoint, they are unlikely to be significant within the United States and even less important if our interest is solely in the east coast. On the other hand, scale economies may be a second important factor. As has been pointed out:

> Economies of large scale operations are pronounced in most petrochemical processes. Within significant ranges, initial capital cost does not rise proportionally with increases in capacity. Since plant and equipment investment cost is high, and consequently fixed charges are large compared to other elements of production cost, it is clear that important economies of scale can be achieved. Furthermore, most petrochemical processes are of the type that require a decidedly less-than proportional increase in direct labor requirements for any given increase in capacity. This tends to increase economies of scale (Isard et al., 1959, p. 157).

Also, the urbanization component of agglomeration economies may be important with respect to petroleum refining and petrochemical complexes.

> These economies (urbanization economies) emerge when unlike plants are spatially juxtapositioned rather than geographically separated . . . in refinery-petrochemical-synthetic fiber complexes, the economy in the use of optimum size power and steam plants is such an economy. This latter economy would not be realized if we were to separate geographically two or more activities, when each had to produce its own power but did not require the output of an optimum steam plant (Isard and Schooler, 1959, p. 28).

Empirically, the transportation cost component of the above discussion has been incorporated into a major study of potential east coast refinery locations by the United States Department of Transportation (Schumaier and Gezen, 1973). The Department of Transportation utilized a heuristic model in an attempt to optimize east coast refinery locations vis-a-vis the locations of several deep-water ports which may be constructed in the area. Variations in the mode (and cost) of transporting crude oil to the refinery and in transporting the refined output to market were simulated. Also, refinery costs were varied in the model as a function of existing refinery completions. That is, elements of the scale economies discussed previously were incorporated. The study concluded that new refinery locations on the east coast would be optimally located in the South Atlantic and Boston regions. A second best alternative appears to be refinery complex concentrations in the South Atlantic region, alone. The model indicates that the least preferred locations exist in the Mid-Atlantic region, overall concentration in the Boston area, and dispersion in the

Mid-Atlantic and Boston regions, respectively. The study indicated that the Mid-Atlantic region would not be selected on the basis of economic factors even if new deep-water ports were to be built in the associated offshore region.

Consequently, it appears likely that the same conclusion would follow if significant petroleum deposits were discovered in the same region. Pipeline costs to connect a new discovery in this region to the preferred refinery locations would be far less than the cost of a deep-water port, per se (Council of Economic Advisers, 1972). Thus, the optimal locations determined by the Department of Transportation model in relation to deep-water port locations should be reinforced if offshore production, rather than foreign crude imports, are utilized as the basis for processing.

In view of this result, it appears highly unlikely that any expansion of refining capacity on the east coast would take place in the Long Island area. As part of the Mid-Atlantic region, it shares the disadvantages indicated by the Department of Transportation study. Moreover, it lacks appropriate infrastructure, which does exist in other regions on the east coast, to permit refinery siting on a least cost basis. For example, no pipelines for either crude oil or petroleum refined products exist on the Island; whereas such transportation modes are a major feature of the New Jersey-Maryland region. In addition, between 65 and 70 percent of existing refinery/petrochemical activities in the New York, New Jersey, Pennsylvania and Delaware region take place within New Jersey or Pennsylvania (A. D. Little, p. 2-3). As a consequence, agglomeration economies can be achieved by expansion of existing refinery sites or location of new refinery facilities in close proximity to those sites. Furthermore, undeveloped land exists near the New Jersey coastline which could provide potential sites for new refinery development. As indicated earlier, these locations are closely related to existing product pipelines and, moreover, are within economical range of all the potential Long Island impact area for an offshore crude oil supply pipeline.

Another feature often ignored in the discussion of requirements for new refinery capacity due to Atlantic Outer Continental Shelf leasing concerns the magnitude of existing capacity and its current source of supply. Presently, PAD district 1 (east coast) refinery capacity totals over 1,329,000 barrels per day. Over 94 percent of this capacity or 1,250,900 barrels per day resides within the Mid-Atlantic region (primarily New Jersey and Pennsylvania)(A. D. Little, Appendix, p. 5-60). Virtually all of the production from these refineries is currently due to foreign imports of crude oil from Venezuela and the Middle East. Previous analysis by the authors has indicated, however, that the entire Atlantic Outer Continental Shelf region may produce under one million barrels per day during its peak production year (Kalter et al., 1974, p. 82). It is interesting to note that under the alternative hydrocarbon pooling assumptions used in this report and given the stipulated leasing schedule discussed previously, maximum production from the Long Island impact region in any one year would be less than 150,000 barrels per day. Although this output would be combined with that from the rest of the Baltimore Canyon area for processing in New Jersey and Pennsylvania refineries, it appears that no new refinery capacity may be needed if these resource estimates are correct and if foreign crude oil imports are backed out. This assumes that no new capacity would be built on the east coast to service increasing demand. Rather, Gulf coast refinery capacity would be expanded to handle the necessary imports to make up any east coast supply-demand deficit. The Department of Transportation study also indicates that if no deep-water ports are constructed along the Atlantic coast (i.e., all major increments to existing imports are handled through the Gulf coast), new refining capacity to handle such imports would be optimally located in the Gulf coast area (p. 4-21).

Finally, political and resource constraints argue that Long Island would not be the site of future refinery construction. As the Department of Transportation study points out, cost differentials between potential refinery sites on the east coast are relatively small (p. 4). Therefore, "factors other than economic costs considered in this study (such as environmental, political, and other considerations) may be more important for new refinery location choices in the east coast than economic costs" (p. 4). Since social opposition is an important variable with respect to location of new refinery growth, Long Island is unlikely to feature very high in the plans of petroleum companies for expansion.

Moreover, the well known problems of the Long Island region with respect to ground water supply argue against this area as a potential location for new capacity. According to a recent analysis by one of the authors, the average refinery required 378 gallons of intake water in 1968 to refine a barrel of crude oil (Stevens and Kalter, 1975). Although some refineries require only 40 gallons per barrel of refined product, most new grass root refinery complexes are in the size range of 150,000 barrels per day. Thus, a new refinery would withdraw at least six million gallons of water daily from ground water sources.

Given all of the available evidence, it is the conclusion of this review that no new petroleum refining capacity will be located on Long Island due to leasing activity in the Atlantic Outer Continental Shelf. As a consequence, neither primary benefits nor disbenefits (environmental emissions) from such developments will accrue to the Long Island region. The possibility does exist for some indirect economic impacts of refinery construction is undertaken in the New Jersey area. Such impacts will probably take place regardless of the reason for refinery expansion, however. Thus, if it is decided to increase our dependence on imported oil and increase the east coast refinery capacity for that oil, similar indirect impacts on Long Island would occur. For that reason, an analysis of such impacts is not undertaken in this report.

<u>Indirect Impacts</u>: In a previous section, we indicated three possible techniques for deriving a regional multiplier value which could then be used to calculate indirect impacts of AOCS leasing. These techniques included economic base studies, regional input-output analysis, and econometric modeling. For our purposes, only the economic base and input-output approaches appear viable. Econometric models are assumed to be beyond the scope of this effort. They are relatively costly and complex to construct and, consequently, are most often used in national forecasting.

In general, the approach requires the use of time series data that would have been difficult to obtain within the resources available for this study. More important, perhaps, is the fact that economic interrelationships derived through the use of econometric modeling techniques may now no longer be valid because of relatively recent changes in the structure of the economy.

Economic Base Analysis: An economic base analysis assumes that all economic activity within a region can be divided into two classifications: those which produce goods and services for export and those which produce for internal consumption. The former is normally called the basic or exporting sector while the latter is commonly termed the service sector. It is assumed that increases in the export sector promote growth in the region due to their resultant effect on the service sector. That is, increases in export initiate a multiplier effect on the entire region. Conversely, a change in imports can have the reverse effect due to the withdrawal of funds from the local economy.

For empirical reasons, employment data is often used as a proxy for income in the actual derivation of a regional multiplier using the economic base approach. This assumes that employment is proportional to income. Then, the regional multiplier can be defined as:

$$M = \frac{1}{1 - \frac{\text{non-basic employment}}{\text{total employment}}} = \frac{1}{\frac{\text{basic employment}}{\text{total employment}}} = \frac{\text{total employment}}{\text{basic employment}}$$

This is comparable to:

$$E_t = E_b + E_s$$

where E_t equals total employment, E_b equals employment in the basic (export) portion of the economy, and E_s equals employment in the service components of the economy. Taking the ratiön E_s/E_b as a constant:

$$E_t = E_b + (E_s/E_b)\ E_b, \text{ or } E_t = (1 + E_s/E_b)\ E_b.$$

Thus, in terms of incremental additions to the basic employment sector, the model can be formulated as:

$$\Delta E_t = (1 + E_s/E_b)\ \Delta E_b$$

Formulated in this manner, the economic base approach assumes that the marginal propensity to spend within the region does not change with the level of total regional income. In reality, this is unlikely to be the case. Import-export relationships will change with changing relative prices and demand.

Consequently, the resulting multiplier should only be considered valid for the short run. Since it is, in reality, based upon the average propensity to consume regionally, the multiplier will tend to be understated for the longer term. Since the marginal propensity to consume regionally tends to increase over time as population and incomes increase, regional reliance on imports will decrease. Forecasting changes in the marginal propensity to consume, however, plague all regional analysis techniques.

Empirically, the most important and difficult aspect of multiplier derivation using an economic base analysis approach is in identifying the export and service components of the regional economy. Although some sectors can be easily delineated as totally export or totally service, most economic sectors are mixed (that is, they produce partly for export and partly for internal consumption). In such cases, the employment must be allocated in an appropriate way. Isard has suggested the use of location quotients (Isard, 1960, pp. 123-126).

Conceptually, several other problems are relevant to an economic base analysis. For example the multiplier value derived is an average and does not necessarily apply to any specific exporting activity. If differentials exist between industries within a region with respect to their geographical sources for intermediate goods, then the average multiplier calculated for the region may not apply to the activities of a specific industry. Moreover, the multiplier cannot take into account long term changes in the trade structure of the region. Finally, using employment, instead of income, as a data base ignores the fact that occupations differ with respect to wage levels. Expansion of a high wage industry will tend to have a greater multiplier effect than that of a low wage industry. As a result of these problems, many regional analysts prefer the use of input-output analysis for measuring the multiplier impacts of exogenous factors affecting a regional economy.

Input-Output Analysis: Whereas the economic base multiplier is an aggregate multiplier and does not measure the impact on various sectors within a region, the input-output approach can be utilized to derive multipliers for individual economic sectors. Conceptually, the analysis divides a regional economy into a number of identifiable industrial and final demand sectors, and shows the interrelationships among them. Using this matrix of intersector flows, mathematical manipulation can be used to derive multiplier values for each sector that take account of both the direct and indirect effects of an exogenous change, plus any induced changes in income resulting from increased consumer spending. Depending upon the data base used, multipliers related to sales, income or employment can be derived (Isard, 1960). As Berry has pointed out:

> The problems of this kind of an analysis are many. Some are similar to those of economic base analysis. Data on interindustry flows are scarce. Linear homogenous relationships do not necessarily obtain, and technical coefficients may well be unstable through time. Production functions may be irregular and stepped or "lumpy" rather than continuous over time. On the other hand, the input-output method of analysis is more general than the economic base method. It spells out specific

multipliers for each industry. Hence, when used in the correct context, it may provide findings of considerable value (Berry, 1967, p. 26).

These conceptual issues, along with the fact that the model is usually applied by forecasting exogenously the primary impacts, raise a major empirical problem for the use of the method. Input-output analysis is highly restrictive in terms of data requirements and can, thus, be both time consuming and expensive to implement for regional areas. Use of national models, as a proxy for regional input-output analysis, is far from satisfactory because of the need to ignore the trade relationships for the region. No satisfactory answer to this problem is available. A rough approximation of regional multipliers can be obtained for a region by comparing it to a similar region(s) in economic size for which models have previously been derived. However, this is usually not a satisfactory method of determining impacts on the various economic sectors because of regional differences. As a result of such data problems, most input-output studies are undertaken only if a variety of potential uses can be seen for the result.

Long Island Multipliers: Given the resource and timing constraints imposed on this study effort, we will derive a set of multipliers for the Long Island area using an economic base analysis. These values will provide one indicator of the economic integration of the region and of the aggregate effect resulting from exogenous economic influences. Although the economic base analysis approach has a number of problems, as indicated above, it has been found by other empirical studies that the aggregate multiplier derived from this form of analysis will be approximately equivalent to the <u>aggregate</u> multiplier from an input-output study of the same region (Isard and Czamanski, 1965; U. S. Army Corps of Engineers, 1969). Therefore, the values derived here may be no less valid than ones that could be obtained from a costly input-output analysis. However, because of the aggregate nature of the resulting multipliers caution should be exercised in their use with respect to specific exogenous changes, like those which may be forthcoming from OCS development.

The basic and service sectors of the Long Island economy were delineated on the basis of available quantitative evidence and subjective judgment (when that evidence was mixed). For most Standard Industrial Classification (SIC) categories, a clear delineation of activity by the basic or service category could be carried out. First hand knowledge of the activities being considered, other published information, and information obtained from regional studies were utilized for this purpose. For "mixed" sectors, the location quotient (Table 14) was used as a primary basis for allocating a sector's activity between the basic and service components. However, that quotient was modified when other available information indicated that it provided misleading results for the region in question. Federal and state government activity was allocated to the basic or export sector while local government activity was considered a portion of the service component of the economy. For all sectors, employment data was used as the common denominator in determining the magnitude of economic activity present. In all cases, 1972 information was utilized because of its availability from the various data sources employed.

Table 19 summarizes the basic and service employment by SIC code sector for Nassau County. The governmental portion of local economic activity is

Table 19.--Basic and Service Employment Distribution in Nassau County by SIC Code Sector[a]

(1972)

SIC Code	Sector	Basic	Service
07			1634
09			85
14			152
15		1016	4066
16			3553
17			15976
19		1055	
20			751
22		1823	
23		4646	
24		1459	1459
25		1662	
26		2618	
27		3369	
28		2904	6069
30		2356	
32		858	
33		1024	
34		6528	
35		6329	
36		17871	
37		14534	4388
38		4067	
39		1646	2265
41			3664
42			4941
44			495
45		1164	107
47		189	757
48			7592
49			4428
50		5683	27185
52		623	2531
53		6644	14698
54		6582	11428
55			9791
56			7458
57			5047
58		1057	17624
59			9634
60			7343
61			2557
62			825
63			6639
64			3087

Table 19.--Con't.

SIC Code	Sector	Basic	Service
65			6091
66			266
67			265
70		1456	215
72			6510
73		9252	11147
75			3517
76			1978
78			1560
79		2700	3121
80		1492	21619
81			1655
82		3585	6403
86			6917
89			4559
	Administrative & Auxiliary Government		6252
Sub-Total		116,192	270,304
91	Federal Government	+ 14,635	
92	State Government	+ 10,202	
93	Local Government		+ 69,417
Total		141,029	339,721

[a]Data sources include County Business Patterns 1972, U. S. Department of Commerce (July 1973), pp. 99-106, 166-172 and A Profile of the Nassau-Suffolk Labor Force, Nassau-Suffolk Regional Planning Board, 1973, p. 15.

displayed separately at the bottom of the table. In Table 20, similar information is shown for Suffolk County. Table 21 summarizes the results for the two counties and Table 22 shows the relevant multiplier values with and without governmental activity being included. Finally, Tables 14 and 23 show the location coefficient and the employment concentrations for each sector, respectively. Both sets of values were utilized in determining the allocation of the individual sectors' total employment between the basic and service aspects.

Table 22 indicates that if 100 man years of labor are newly employed within the Long Island region to service an export demand, an additional 226 man years of economic activity would be expected as a result of the multiplier (or round-by-round respending) effect. Inclusion of the governmental sectors in the analysis, however, reduces the multiplier so that only 218 additional persons would be employed. This results from the change in the basic to service ratio. The appropriate multiplier to utilize depends upon one's judgment with respect to increased governmental employment due to exogenous changes in imports. If proportional increases in the respective governmental sectors could be anticipated, the multiplier value derived from the inclusion of the governmental sectors would appear most appropriate. However, this is usually considered a rather heroic assumption. Consequently, the governmental sector is often excluded from consideration in this type of analysis. In any case, the differences shown are relatively small and, given the other uncertainties present, any choice would surely be spurious accuracy.

Although the overall regional multiplier appears to lie between the multiplier values for the respective counties, this is probably not an accurate representation of the real world. Rather, it appears to be largely due to the fact that the delineation of economic sectors, within the respective counties, by export and service components, was done on a regional rather than county-by-county basis. As a result, the multiplier values displayed for the individual counties are probably overstated. The overall multiplier value for the region would be accurate given the methodology utilized.

The values shown in Table 22 can be utilized in conjunction with the primary export effects of AOCS leasing to approximate an overall employment and sales impact on the Long Island region. That is, the total (direct, indirect and induced) effect of changes in final demand for Long Island products and services would approximately equal the direct effect times the appropriate multiplier value. In that regard, the values in Table 15 and the discussion of employment impacts in that same section are relevant. Total employment or sales impacts are not to be considered as net changes in regional income. Only that portion which can be classified as regional value added would change the net income. Since direct environmental disbenefits were not quantitatively determined, no link between this direct-indirect relationship can be displayed.

Table 20.--Basic and Service Employment Distribution in Suffolk County by SIC Code Sector[a]

(1972)

SIC Code	Sector	Basic	Service
07			1208
09			182
14			79
15		477	1907
16			1530
17			7806
19		468	
20			2042
22		1472	
23		5115	
24		309	309
25		1007	
26		983	
27		2618	
28		796	
30		1661	
32		1032	
33		596	
34		4284	
35		3200	
36		13508	
37		4299	1303
38		1726	
39		860	
41			2398
42			1832
44			326
45		130	165
47			151
48			4233
49			2469
50			9952
52		314	1554
53		3570	6999
54		4691	5443
55		434	5494
56			3469
57			1889
58		621	8390
59			5735
60			3938
61			745
62			212
63			2930
64			789

Table 20.--Con't.

SIC Code	Sector	Basic	Service
65			1841
66			152
70		828	367
72			2815
73		85	5307
75			1318
76			1171
78			846
79		398	1486
80		2810	10293
81			1026
82			2971
86			2918
89			3435
	Administrative & Auxiliary Government		2728
Sub-Total		58,292	124,153
91	Federal Government	+12,157	
92	State Government	+22,609	
93	Local Government		+47,041
Total		93,058	171,194

[a]Data sources include County Business Patterns 1972, U. S. Department of Commerce (July 1973), pp. 99-106, 166-172 and A Profile of the Nassau-Suffolk Labor Force, Nassau-Suffolk Regional Planning Board, 1973, p. 15.

Table 21.--Basic and Service Employment Totals for Nassau-Suffolk Counties (1972)

County	Without Government		With Government	
	Basic	Service	Basic	Service
Nassau	116,192	270,304	141,029	339,721
Suffolk	58,292	124,153	93,058	171,194
TOTAL	174,484	394,457	234,087	510,915

Table 22.--Nassau-Suffolk Region Economic Base Multipliers (1972)

County	Without Government	With Government
Nassau	3.33	3.41
Suffolk	3.13	2.84
Nassau-Suffolk	3.26	3.18

Table 23.--Nassau-Suffolk Employment Concentrations*
(1972)

Rank	Sector	Employment	Percent of Total
1	Wholesale Trade	42,820	7.78
2	Medical and Other Health Services	36,214	6.58
3	General Merchandise	31,911	5.79
4	Electrical Equipment and Supplies	31,379	5.70
5	Food Stores	28,144	5.11
6	Eating and Drinking Places	27,692	5.03
7	Miscellaneous Business Services	25,791	4.68
8	Transportation Equipment	24,524	4.45
9	Special Trade Contractors	23,282	4.23
10	Automotive Dealers and Service Stations	15,719	2.85
11	Miscellaneous Retail Stores	15,369	2.79
12	Educational Services	12,959	2.35
13	Communication	11,825	2.15
14	Banking	11,281	2.05
15	Apparel and Accessory Stores	10,927	1.98
16	Fabricated Metal Products	10,812	1.96
17	Nonprofit Membership Organizations	9.835	1.79
18	Chemicals and Allied Products	9,769	1.77
18	Apparel and Other Textile Products	9,761	1.77
19	Insurance Carriers	9,569	1.74
20	Machinery, Except Electrical	9,529	1.73
21	Personal Services	9,325	1.69

Table 23.--Con't.

Rank	Sector	Employment	Percent of Total
22	Miscellaneous Services	7,994	1.45
23	Real Estate	7,932	1.44
24	Amusement and Recreation Services	7,705	1.40
25	General Building Contractors	7,466	1.36
26	Furniture and Home Furnishings Stores	6,935	1.26
27	Electric, Gas and Sanitary Service	6,897	1.25
28	Trucking and Warehousing	6,773	1.23
29	Local and Interurban Passenger Transit	6,062	1.10
30	Printing and Publishing	5,987	1.09
31	Instruments and Related Products	5,793	1.05
32	Heavy Construction Contractors	5,083	.92
33	Building Materials and Farm Equipment	5,022	.91
34	Auto Repair, Services and Garages	4,835	.88
35	Miscellaneous Manufacturing Industries	4,771	.87
36	Rubber and Plastic Products	4,017	.73
37	Insurance Agents, Brokers and Service	3,876	.70
38	Paper and Allied Products	3,601	.65
39	Lumber and Wood Products	3,536	.64
40	Textile Mill Products	3,295	.60
40	Credit Agencies other than Banks	3,302	.60
42	Miscellaneous Repair Services	3,149	.57
43	Hotels and Other Lodging Places	2,866	.52
44	Food and Kindred Products	2,793	.51
45	Legal Services	2,681	.49

Table 23.--Con't.

Rank	Sector	Employment	Percent of Total
46	Furniture and Fixtures	2,669	.48
47	Motion Pictures	2,406	.44
48	Agricultural Services and Hunting	2,022	.37
48	Stone, Clay and Glass Products	2,056	.37
50	Primary Metal Industries	1,620	.29
51	Transportation by Air	1,566	.28
51	Ordnance and Accessories	1,523	.28
53	Transportation Services	1,097	.20
54	Security, Commodity Brokers and Services	1,037	.19
55	Water Transportation	821	.15
56	Combined Real Estate, Insurance, Etc.	418	.08
57	Fisheries	267	.05
58	Nonmetallic Minerals, Except Fuels	231	.04

*Source: County Business Patterns 1973, (Washington: GPO), 1973.

Net Fiscal Burden: Because energy resources are not equally spread throughout the country, development of any one resource location may cause regional dislocations and inequalities. It has been argued that leasing imposes a net fiscal burden on the jurisdictions surrounging or adjacent to leased acreage. Requirements for schools, hospitals, transportation systems and other infrastructure necessary to service development activity occurring in leasing areas, along with the increased work force and associated population, may require public revenues in excess of those raised by additional taxes. In addition, adverse environmental impacts may result in regional disbenefits to such industries as recreation and fisheries, and to the public as a whole.

The Department of the Interior has long argued that, for the average state or region, no net fiscal burden was generated by activities such as offshore leasing. The claim is that the increase in economic activity due to leasing also increases revenue through the tax system (U. S. Congress, Senate, 1972, pp. 77-79). However, due to the distribution of economic activity across the nation and because of different socioeconomic characteristics of specific labor forces involved, the net impacts are likely to vary widely. Gulf coast states, for example, may achieve substantial benefits from Atlantic coast drilling because most of the support industry is already located in that region. However, this does not necessarily provide an indication of net fiscal burden for the respective regions. The net fiscal burden for a specific political entity would equal the difference between public funds required to provide necessary public services for the increased economic activity due to leasing and the increased revenue raised through the tax system because of this activity. Obviously, two regions with comparable requirements for increased public services and comparable increases in economic activity may differ widely with respect to net fiscal burden. The tax base and tax structure in place in a given region will be, ceteris paribus, the determining factor. Many east coast locations, such as Long Island, with well developed tax bases and high tax rates are in a position to take better advantage of any increase in economic activity due to OCS leasing.

As indicated above, however, the total impacts (direct and indirect) on Long Island of AOCS leasing appear to be minimal given the current population, work force, regional income and gross output. Aside from the potential increase in public services which may be required due to possible oil spills, the magnitude of possible employment and sales increases due to leasing activity does not appear sufficient to overburden existing infrastructure.

Politically, however, demands have been building for some time for sharing the revenues due to leasing activity on the public domain. The problem is twofold. First, it is the "public" domain so that those areas not adjacent to leased areas may also have a legitimate claim on any shared revenue. Second, the derivation of an equitable formula for compensating impacted states or regions is complex and often difficult to implement. Ideally, those suffering a net fiscal burden should be compensated; but, conversely, those benefiting should be willing to aid in this compensation. Then, any across-the-board revenue sharing (to all states) could be done equitably. The measurement problems involved, however, are both severe and intertwined with jurisdictional questions. And now that leasing activity has begun to generate substantial amounts of government revenue on a sustained basis, these problems will become major political issues. In the end, a satisfactory formula will have to be found for revenue sharing. Society does not appear ready to accept the equity implications of our current approach to this problem. Coupled with proper environmental safeguards, a satisfactory solution to the regional questions now being raised may be the single most important political factor in establishing a long term comprehensive leasing policy.

Congress apparently recognized this fact as far back as 1920 when they passed the Mineral Leasing Act. This legislation allocated 37.5 percent of the federal revenues collected from oil shale, coal and onshore petroleum development back to the affected states for use in financing schools, hospitals and highways. An additional 52.5 percent was credited to the Reclamation Fund which is, in essence, used for development of productive agricultural activity in the western states (those most affected by the 1920 act). If a comparable amount of federal revenue was shared from OCS leasing, $276 million of revenue could be generated from the Long Island impact area for the areas having jurisdiction. This value is calculated on the basis of a 37.5 percent return of total royalties and bonuses discounted at an annual rate of 12 percent. It is based upon our previously described hypothetical leasing schedule for pooling assumption number one. The values would be somewhat lower for pooling assumption number two.

Conclusions: Given the above conceptual and descriptive discussions, we are now in a position to summarize the potential economic impacts of hydrocarbon development in the Atlantic Outer Continental Shelf on the Long Island region. Generally speaking, the potential for economic impact depends upon the industrial structure of the region, regional unemployment, manpower needs, the availability of trained personnel and the location of the productive activity. We have hypothesized that exploration and production of hydrocarbon resources will take place within the market supply area of the Long Island region. However, we have also shown that it is unlikely that refineries will be located within that region.

It is important to note that the analysis of refinery location in many ways predetermines our impact results since the most significant long term regional effects of oil and gas production are promoted primarily through the operation of refineries and associated petrochemical complexes. The second most significant impact takes place through the direct linkages between offshore activities and the supply of factors of production. We have seen that oil and gas exploration and production is highly capital intensive. For each dollar's worth of petroleum and natural gas produced, less than six cents goes directly to labor. Thus, the direct employment in the offshore areas and the onshore support force for that activity would tend to result in relatively minor population increases for the regions affected. Coupled with the fact that much of this labor force is highly mobile, temporary and apt to be spread among several coastal bases of operations, regional impacts for Long Island due to population or labor force changes appear small.

Increased sales potential for regional economic sectors does appear possible if those sectors can be competitive as a source of supply for offshore activity. Our analysis has indicated that the maximum potential impact for such increase in regional sales over a 31 year leasing, development and production period would be $265 million. Given a relatively high economic base multiplier (greater than 3), we can assume that the Long Island economy would generally "capture" many of the indirect effects promoted by this increase in sales. On the other hand, many of the factors that are required for oil and natural gas exploration-production are highly specialized (e. g., rig and platform fabrication) and are not indigenous to the Long Island economy. Thus, the impact from such activities on the region would be negligible and was not included in the potential sales increase which might accrue to the region.

In conclusion, the total economic impact of AOCS leasing activity on Long Island will probably be relatively minor. Many of the factors that would promote a more substantial impact (e. g., refinery operations, rig and platform fabrication, and the availability of highly skilled petroleum oriented labor) will not be found on Long Island. The as yet unknown potential in the equation relates to environmentally induced disbenefits. Although our analysis has indicated the process required to estimate such impacts, sufficient information is not currently available to determine their probable economic effect. It is clear, that as exploration activity takes place closer to the region's shoreline, the probability of environmental damage from possible oil spills increases. Additional information on the question surrounding probable damages from such spills seems to be an important aspect of any future research. Without additional physical data, economic forecasting will be difficult.

EFFECTS OF INFORMATION CONSTRAINTS

As the reader is by now, no doubt, aware, this analysis is fraught with uncertainty. In some cases the uncertainty is so large that quantitative impact estimates would be rendered meaningless and were not attempted. Yet, in other areas, the analysis was conducted even though high uncertainty remained. In this chapter, the entire effort will be cast in the light of this uncertainty.

Uncertainty due to inadequate geologic information, due to changing technology, and derived from the process of impact estimation will be discussed. In general, we will conclude that the level of uncertainty is such that both the quantitative and qualitative estimates must be viewed and used with caution. Nonetheless, in the everyday world, decisions must be made based on the best available information regardless of its inherent uncertainty. In this paper, we have tried to depict what might be the economic impacts of AOCS drilling and production. Now it is incumbent upon us to also discuss the uncertainties in our estimates. The political decisions regarding AOCS production are extremely important to a large number of U. S. citizens, and the decision makers should have knowledge of both what the likely impacts are to be and the uncertainty inherent in those impact estimates.

In terms of reserve estimates, especially relating to the Long Island impact area, it is easier to state what we know with certainty: nothing. Reserve estimates for the entire AOCS have been derived by extrapolating from areas in the U. S. with similar geologic structure. The extrapolation is performed by comparing the oil recovered over large areas of the U. S. with a known volume of sedimentary rock to the estimated volume of sedimentary rock below the AOCS. In other words, an oil recovery factor (barrels/cubic mile of sedimentary rock) is multiplied by the estimated AOCS volume of sedimentary rock to produce an estimate of recoverable oil. The validity of the technique depends on the size of the area for which the projection is being made, among other factors. When extrapolating over very large areas, such as the entire 75 million acre AOCS from areas of somewhat similar geologic formation, reasonable estimates of recoverable reserves can be obtained. In similar geologic areas, the formation of oil pools may be viewed as a stochastic process, and extrapolation of an average rate to a large area may produce reliable estimates (by the law of large numbers).[5] However, when this technique is applied to small areas, the condition of large numbers is violated and the resulting estimates are of dubious validity. Hence, the quantitative reserve figures developed in this paper for the Long Island impact area should be viewed as merely hypothetical numbers taken for purposes of illustration. There is no way of developing better estimates until exploratory drilling is undertaken in the area.

A decision on AOCS leasing must inevitably consider the consequences of future technical change. Technology assessment is one of the more difficult areas of analysis because the uncertainty is so high. Often technology

---

[5] We are here abstracting from the debate between advocates of the volumetric and mathematical approaches to reserve estimation.

is assumed constant, because no basis can be established for alternative assumptions, or because it is unclear how the new technology would affect prior statistical results (as in Devanney and Stewart, April 1974). However, in fields with rapidly changing technology such as AOCS drilling and production, this assumption is clearly in error and leads to a bias in the results. All that can be done is to recognize this bias, point out to decision makers the direction of the bias, and present any professional judgements on how important it may be. For AOCS production, the results of oil spill statistics are clearly biased on the high side if new technology and production regulations are taken into consideration. The authors have no idea what the magnitude of the bias might be. It can be said that the historical statistics probably represent the worst case in terms of spill probabilities.

Another area of uncertainty is in the process of estimating economic impacts. Long Island is clearly an open economy in that goods and services are freely traded with surrounding areas and other parts of the country to yield the consumption and production packages of Long Islanders. In comparative static economic analysis, it is very difficult to "freeze" this dynamic process to project (and isolate) the economic costs and benefits that accrue to Long Island alone from regional developments. The resulting estimates are highly uncertain since a number of limiting assumptions must be made either because of data problems or because of the nature of the analytic process itself. This uncertainty results from any regional analysis, but is compounded when the region is small and when the quantitative inputs to the analysis are also highly uncertain.

The final major area of uncertainty, and in a sense the largest, is uncertainty regarding future development in the Long Island region in the absence of any AOCS leasing and drilling. What would be the economic impacts on Long Island of increases in imported oil, especially oil imported through nearby ports? What would be the incidence of tanker oil spills reaching Long Island because of increased volume of imports? These and other questions must be answered before economic, social and environmental development patterns can be projected in the absence of AOCS leasing. Then, and only then, can the correct comparison between the conditions <u>with</u> AOCS leasing and the conditions <u>without</u> the leasing be made. In this regard, all analytic efforts to date have been sorely lacking, primarily because of data limitations and the expense of the task involved. This limitation should be borne in mind when the results of this and other analyses are applied to the Long Island situation.

Despite the high degree of uncertainty on projected impacts, government policy decisions on AOCS leasing can and will be made. Fortunately, the AOCS policy questions do not demand simple, uniform and for all time answers. If leasing is undertaken, it will take place on selected tracts over a period of years. Selection of lease areas and lease tracts can incorporate not only prospective reserve information but also data on potential environmental and regional economic consequences. Via the political and judicial processes, localities can oppose or encourage leasing in any given area. It is hoped that the analysis in this study, and the other studies which have preceded it, will assist government officials in the Long Island area to establish and advocate a posture which is in the best interest of their citizens.

REFERENCES

Ahern, William R., Jr. Oil and the Outer Coastal Shelf, The Georges Bank Case. Cambridge: Ballinger Press, 1973.

American Petroleum Institute. Quarterly Review of Drilling Statistics for the United States. Washington, 1974.

Berry, Brian J. L. Strategies, Models, and Economic Theories of Development in Rural Regions. Agricultural Economic Report No. 127, Economic Research Service, U.S.D.A., December 1967.

Council of Economic Advisors. The Economics of U. S. Deepwater Ports. Final Report of the Energy Subcommittee Working Group on Deepwater Ports. March 2, 1973, mimeo.

Council on Environmental Quality. OCS Oil and Gas - An Environmental Assessment. April 1974.

Devanney, J. W. III, and Robert J. Stewart. "Long Island Spill Trajectory Study." Report to Regional Marine Resources Council, Nassau-Suffolk Planning Board. Massachusetts Institute of Technology, February 1974.

Devanney, J. W. III, and Robert J. Stewart. "Oil Spill Statistics." Report to the Council on Environmental Quality. Massachusetts Institute of Technology, April 1974.

Devanney, J. W. III, and Robert J. Stewart. "Probabilistic Trajectory Assessments for Offshore Oil Spills Impacting Long Island." Report to Regional Marine Resources Council, Nassau-Suffolk Planning Board. Massachusetts Institute of Technology, November 1974.

Ellis, Walter. National Petroleum Council. Personal Communications. 1974.

Gulf South Research Institute. Offshore Revenue Sharing: An Analysis of Offshore Operations on Coastal States. Baton Rouge, Louisiana, 1973.

"The Input-Output Structure of the U. S. Economy: 1967." Survey of Current Business. February 1974.

Isard, Walter. Methods of Regional Science. Cambridge: The MIT Press, 1960.

Isard, Walter. Location and the Space Economy. Cambridge: The MIT Press, 1972.

Isard, Walter, and Stanislaw Czamanski. "Techniques for Estimating Local and Regional Multiplier Effects of Changes in the Level of Major Governmental Programs." Peace Research Society Papers, III. Chicago Conference, 1965.

Isard, Walter and Eugene W. Schooler. "Industrial Complex Analysis, Agglomeration Economies, and Regional Development." Journal of Regional Science, Spring 1959, p. 20.

Isard, Walter, Eugene W. Schooler, and Thomas Vietorisz. Industrial Complex Analysis and Regional Development. Cambridge: The Technology Press, 1959.

Kalter, R. J., T. H. Stevens, and W. E. Tyner. Atlantic Outer Continental Shelf Energy Resources: An Economic Analysis. A. E. Research Paper No. 74-17, Cornell University, November 1974.

Kamer, Pearl M. The Long Island Economy: Anatomy of Change. Nassau-Suffolk Regional Planning Board, December 1971.

Lahman, H. S., J. B. Lassiter III, and J. W. Devanney III. Simulation of Hypothetical Offshore Petroleum Developments. Report to the Council on Environmental Quality. Massachusetts Institute of Technology, April 1974.

Little, A. D. Potential Ohshore Effects of Deepwater Oil Terminal-Related Industrial Development. Volume II of IV. Report to the Council on Environmental Quality. Cambridge, Massachusetts.

Little, A. D. Potential Onshore Effects of Deepwater Oil Terminal-Related Industrial Development. Volume IV of IV (Appendices). Report to the Council on Environmental Quality. Cambridge, Massachusetts.

Mosteller, Frederick, R. E. K. Rourke, and G. B. Thomas, Jr. Probability and Statistics. Reading, Massachusetts: Addison-Wesley, 1961.

Nassau-Suffolk Regional Planning Board. A Profile of the Nassau-Suffolk Labor Force, 1973.

National Petroleum Council, Committee on Possible Future Petroleum Provinces. Future Petroleum Provinces of the United States. Washington, 1970.

National Petroleum Council. U. S. Energy Outlook. Washington, December 1972.

National Petroleum Council. U. S. Energy Outlook: Oil and Gas Availability. Washington, 1973.

National Petroleum Council. Ocean Petroleum Resources: An Interim Report. July 1974.

Perloff, Harvey S. How a Region Grows, Area Development in the U. S. Economy. Supplemental Paper No. 17, published by the Committee for Economic Development, March 1963.

Pratt, Wallace. "Petroleum on the Continental Shelves." Bulletin of American Association of Petroleum Geologists. 31(1947):657-672.

Resource Planning Associates, Inc., and David M. Dornbusch and Company. Potential Onshore Effects of Oil and Gas Production on the Atlantic and Gulf of Alaska Outer Continental Shelf. Prepared for Executive Office of the President, Council on Environmental Quality. December 1973.

Russell, W. L. Principals of Petroleum Geology. New York: McGraw-Hill Book Company, Inc., 1960.

Schrader, B. P., S. F. Moore, B. B. Ackerman, A. D. Long, and L. H. Tower. Potential Biological Effects of Hypothetical Oil Spills Occurring in the Nearshore Waters of Long Island's South Shore. Report to the Nassau-Suffolk Regional Planning Board. Massachusetts Institute of Technology, June 1974.

Schumaier, C. Peter, and Asil Gezen. Economic Aspects of Refinery-Deep Water Port Dispersion. U. S. Department of Transportation. Washington, May 1973.

Spivak, J., and O. B. Shelburne. "Future Hydrocarbon Potential of Atlantic Coastal Province." Future Petroleum Provinces of the United States - Their Geology and Potential, ed. I. H. Cram, pp. 1295-1310. Tulsa: The American Association of Petroleum Geologists, 1971.

Stevens, T. H., and R. J. Kalter. "The Economics of Oil Shale Resource Allocation Policy." Paper presented to the Western Agricultural Economics Research Council, Reno, January 1975.

Stewart, Robert J., J. W. Devanney III, and William Briggs. Oil Spill Trajectory Studies for Atlantic Coast and Gulf of Alaska. Report to the Council on Environmental Quality. Massachusetts Institute of Technology, April 1974.

Theobald, P. K., S. P. Schweinfurth, and D. C. Duncan. Energy Resources of the United States. Geological Survey Circular 650, 1972.

U. S. Congress, Senate, Committee on Commerce. National Ocean Policy Study. Government Printing Office, 92nd Cong., 2nd sess., November 1974.

U. S. Congress, Senate, Committee on Interior and Insular Affairs. Federal Leasing and Disposal Policies. Government Printing Office, 92nd Cong., 2nd sess., June 19, 1972.

U. S. Department of the Army, Corps of Engineers. Report for Development of Water Resources in Appalachia. Part IV. Office of Appalachian Studies, September 1969.

REFERENCES (Con't.)

U. S. Department of the Army, Corps of Engineers. U. S. Deepwater Port Study. Volume III of V. IWR Report 72-8, August 1972.

U. S. Department of Commerce. County Business Patterns 1972. Washington: Government Pringint Office, 1973.

U. S. Department of the Interior, Bureau of Land Management. The Role of Petroleum and Natural Gas From the Outer Continental Shelf in the National Supply of Petroleum and Natural Gas. Washington, May 1970.

U. S. Department of the Interior, Bureau of Land Management. Atlantic Outer Continental Shelf Office, Description of Proposal, 1974, mimeo.

U. S. Department of the Interior, Bureau of Mines Information Circular 8557. Offshore Petroleum Studies. Washington, 1972.

U. S. Geological Survey, Department of the Interior. "Comparison and Discussion of Some Estimates of United States Resources of Petroleum Liquids and Natural Gas." Outer Continental Shelf Policy Issues, Appendix 2. Senate Committee on Interior and Insular Affairs, 92nd Cong., 2nd sess., ser. 92-27, pt. 1, 1972.

Weaver, Paul. "Variations in History of Continental Shelves." Bulletin of the American Association of Petroleum Geologists. 34(1950):351-360.

Weeks, L. G. "World Offshore Petroleum Resources." Bulletin of the American Association of Petroleum Geologists. 49(1965):1680-1693.