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Outer Continental Shelf Oil and Gas Costs & Production Volume: Their Impact on the Nation's Energy Balance to 1990

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OUTER CONTINENTAL SHELF
OIL ANO GAS COSTS AND PRODUCTION VOLUME:
THEIR IMPACT ON THE NATION'S
ENERGY BALANCE TO 1990

Arthur D Little, Inc.

BLM CONTRACT CT 5-48

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FOREWORD

This study of future expected OCS production volumes and costs has been undertaken at a time when the majority of the OCS areas are largely unexplored and when little information is available on the resource base, the geology, or the production technologies which will be feasible. As a result, the methodology of this study has allowed for the projection of results under uncertainty with analogous information about conditions in overseas environments which may be similar to the new OCS areas.

Resource projections, based upon those available from the USGS at this time, are considered preliminary by the experts who have assembled them and new projections on critical information items such as oil and gas in place, field-size distributions and well productivities are currently being prepared, but will not be available for some time to come.

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SUMMARY

A. PURPOSE AND SCOPE

For more than twenty years, both government and industry have looked with great interest on the U.S. Outer Continental Shelf because of its potential as a large source of oil and gas. There are significant questions, however, about which areas of the Outer Continental Shelf (OCS) are the best prospects with regard to attainable production, landed costs, and capital requirements for exploration, development and production.

These questions are important to the companies who lease individual tracts from the Federal Government for exploration and development. They are also important to the Bureau of Land Management (BLM) which manages this leasing process. BLM requires basic data on the costs of finding and producing oil and gas from the OCS so it can judge the potential profitability of proposed leases. It also needs to know the total productivity of an OCS area under specific price expectations and the likely impact of this productivity on energy supply and demand.

The objectives of this study, therefore, have been to:

- determine the costs of finding and producing oil and gas in the OCS,
- estimate the quantities likely to be produced in 1980, 1985 and 1990 under various price scenarios, and
- estimate the potential regional and national impact on energy demand and supply.

This report presents the results of that study. Two points must be emphasized :

- The estimates of potential oil and gas production from new OCS areas as presented in this report were based on the 1975 OCS Planning Schedule, which includes sales through 1978, and on the oil and gas resource estimates provided by the United States Geological Survey*. Any change in either the OCS Planning Schedule or in the resource estimates of the USGS will necessarily reflect on the projected production volumes presented in this report.

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*Geological Survey Circular 725, "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States," USGS 1975.

- The resource estimates for the Outer Continental Shelf provided by the USGS are for offshore areas with water not deeper than 600 feet. As a consequence, potentially productive areas with waterdepth greater than 600 feet as they exist, for example in the Gulf of Mexico and offshore Southern California, are not covered by this study. This may have resulted in a low estimate of "typical" field development costs for Southern California, where large mess with high resource potential are in waters deeper than 600 feet.

I?. APPROACH

The basic approach to the study was as follows. First, the 17 OCS areas, designated by the BLM, were grouped into seven larger areas (Table 1), considered to represent major differences in climatic conditions which significantly impact on petroleum exploration and development costs.

TABLE 1

CCS AREAS ANALYZED

Study Areas	BLM OCS Areas Included
Atlartic	Areas 1, 2, and 3
Gulf of Mexico	Areas 4, 5, and 6
Pacific Coast	Areas 7, 8, 9, and 10
Gulf of Alaska	Areas 12 and 13
Lower Cook Inlet and Bristol Bay	Areas 11 and 14
Bering Sea and Chukchi Sea	Areas 15 and 16
Beaufort Sea	Area 17

For each of these areas, exploration, development and production costs were calculated based on information assembled from industry sources and the public domain. Since these costs are sensitive to the size of a field and the rate at which it is developed, development and production costs for nine different field sizes were investigated; summaries of the results for three of the field sizes considered as representative for [illegible] this report.

Oil (10^6 bbls)	Gas (10^{12} ft.^{3})
45	0.25
150	1.0
2000	10.0

Average well production rates of 2500 barrels of oil per day and 50 MCF of gas per day were assumed except in the Gulf of Mexico and in areas offshore California. The prevailing rates of 500 barrels per day and 20 MCF per day per well were used for areas in the Gulf of Mexico and 500 barrels per day and 50 MMC per day were used for areas offshore California.

On the basis of indicated likely drilling sites and an assessment of the likely operating conditions in the different areas the following offshore distances, water depths and number of years to first production following the first discovery well were used in the analysis.

	Offshore Distance (miles)	Water Depth (feet)	Years to First Production
Atlantic	75	400	4
Gulf of Mexico	75	400	3
Pacific Coast	15	600	4
Gulf of Alaska	25	400	5
Lower Cook Inlet and Bristol Bay	15	200	5
Bering Sea and Chukchi Sea	75	200	5
Beaufort Sea	15	300	5

Using probabilistic estimates made by the USGS of the amounts of oil and gas present on the OCS, the 1975 OCS Planning Schedule of the BLM and the results of the previously mentioned cost analysis, probabilistic projections of oil and gas production and related capital requirements for each of the 16 individual areas contained in the lease schedule were made. Furthermore, to allow for the differences in costs between areas and between different parts of the resource base within each area, these projections were made under different price scenarios ranging from $4.50/Bbl ($0.75/MCF) to $18.00/Bbl ($3.00/MCF).

Finally, the potential impact of the nation's oil and gas supply/demand balances was assessed, using the expected values (i.e. , the statistical mean) of the production forecasts for new OCS areas obtained under a low and high price scenario in conjunction with high and low projections of potential production from onshore areas and existing offshore areas.

C. EXPLORATION AND DEVELOPMENT COSTS

Exploration and development costs between areas can vary by almost 100%. For a typical field (150 million barrels of oil, 2500 billion cubic feet of gas) exploration well drilling and field development costs are as follows:

	Field Development Costs (Millions of 1975 Dollars)		Costs of One Exploration Well
	oil	Gas	
Beaufort & Chuckchi Seas	188	172	10.
Gulf of Alaska	184	196	5*3
Bering Sea & Bristol Bay	150	187	7.2
Gulf of Mexico	144	157	2.0
Atlantic Coast	127	166	2.1
Lower Cook Inlet	124	118,	4.4
Pacific Coast	148	112	2.0

Unit Costs will vary" widely depending on the size of the field. In the Atlantic OCS, for example, unit costs will be:

Oil Reserves* (MM bbls)	$/bbls of Daily Production Capacity
45	7390
150	3740
2000	2530

Gas Reserves (10^{12} ft. ^{3})	$/MCF Daily Production Capacity
0 . 2 5	1255
1.0	515
10.0	260

The greater economies of scale for gas fields are the result of the larger investment required in well-to-shore transportation.

These costs can be translated into minimum required prices -- the minimum price that a company must obtain to cwer the after tax costs of exploration, development and production. The minimum price will vary with the location and size of a field and with the rate of return desired by the company. Tables 2 and 3 show minimum required prices for three field sizes and three rates of return in each of the seven OCS areas analyzed.

The differences in minimum required prices for different field sizes and different rates of return are quite striking. For example. at the present day wellhead price of $11.28/Bbl, a 45-million barrel field in the Lower Cook Inlet would "be considered economical with a minimum required price of $10.63 if the company were satisfied with a 10% rate of return. If the company desired a 25% rate of return, however, even a 150 million barrel field would not be considered economical at a minimum required price of $11.99/Bbl. Table 4 shows the minimum field sizes which, under favorable conditions, would be economical, if wellhead prices were $12/barrel for oil and $1.25/MCF.

D. ANTICIPATED PRODUCTION FROM NEW OCS AREAS

1. Probabilistic Projections

From the cost data, the probabilistic USGS's resource estimates and BLM's June 1975 Planning Schedule, we projected production volumes at different levels of confidence and under price scenarios ranging from $4.50/Bbl ($0.75/MCF) to $24.00/Bbl ($4.00/MCF).*

The probabilistic projections, made for the 16 individual areas contained in BLM's Planning Schedule, were combined into probabilistic forecasts for the following four geographical areas and for all areas combined:

(1) Offshore Atlantic Coast,

(2) The Gulf of Mexico,

(3) Offshore Pacific Coast, and

(4) Offshore Alaska.

The results of these probabilistic projections for confidence levels of 5%, 50% and 95%, based on wellhead prices of $12.00/Bbl and $1.25/MCF, respectively, are shown in Tables 5 and 6 for the target years of 1980, 1985 and 1990. The confidence levels of 5%, 50% and 95% represent, respectively, a very unlikely (1 in 20), a moderately likely (1 in 2) and a very likely" (19 in 20) expectation that the stated production will be advanced.

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* Based on production of 2500 barrels per day.

TABLE 2

MINIMUM REQUIRED PRICE: OIL

(1975 dollars/barrel)

Field Size (10^6 Bbl)	45			150			2000		
Rate of Return (%)	10	15	25	10	15	25	10	15	25
Atlantic	6.70	8.85	14.61	4.45	5.82	9.40	2.78	3.57	5.56
Gulf of Mexico	6.01	7.78	12.17	4.53	5.81	8.94	3.92	4.98	7.49
Pacific	6.93	9.31	15.62	3.90	5.27	8.75	2.65	3.43	5.46
Gulf of Alaska	14.22	19.63	34.79	7.23	9.84	17.20	4.29	5.67	9.39
Lower Cook Inlet	10.63	14.23	24.18	5.46	7.19	11.99	3.17	4.04	6.34
Bering Sea	12.44	16.70	28.94	6.72	8.86	14.85	3.65	4.64	7.26
Beaufort Sea	17.41	23.78	41.88	8.59	11.42	19.49	4.80	6.08	9.57

TABLE 3

MINIMUM REQUIRED PRICES: GAS

(1975 dollar/MCF)

Field Size (10^{12} ft^3)	0.25			1			10		
Rate of Return (%)	10	15	25	10	15	25	10	15	25
Atlantic	1.02	1.36	2.31	0.59	0.75	1.17	0.40	0.48	0.70
Gulf of Mexico	0.83	1.06	1.66	0.50	0.61	0.90	0.39	0.45	0.60
Pacific	1.11	1.50	2.57	0.53	0.67	1.08	0.34	0.40	0.60
Gulf of Alaska	2.45	3.45	6.30	0.97	1.30	2.26	0.51	0.64	1.03
Lower Cook Inlet	1.71	2.37	4.22	0.66	0.87	1.47	0.33	0.41	0.63
Bering Sea	2.04	2.82	5.12	0.91	1.18	1.96	0.49	0.59	0.88
Beaufort Sea	3.03	4.23	7.72	1.13	1.50	2.56	0.54	0.65	1.01

TABLE 4

MINIMUM ECONOMIC FIELD SIZE [1]

Rate of Return	Gas (Billions of cu. ft.) Wellhead Price $1.25/MCF 10%	15%	25%	Oil (Millions of Bbls) Wellhead Price $12.00/Bbl 10%	15%	25%
Atlantic	180	290	660	17	26	70
Gulf of Mexico	120	185	400	11	17	47
Pacific	220	300	770	18	30	74
Gulf of Alaska	660	1100	5400	60	97	425
Lower Cook Inlet	370	560	1550	37	58	150
Bering Sea	600	930	4400	49	80	260
Beaufort Sea	850	1600	6400	80	135	560

[1] In Recoverable Reserves.

TABLE 5

ANNUAL OIL PRODUCTION LEVELS FROM
CONSOLIDATED OCS AREAS AT DIFFERENT CONFIDENCE LEVELS[1]
(million barrels per year)

	Confidence Levels	Year of Production 1980	1985	1990
Offshore Atlantic Coast	95%	0	0	0
	50%	50	130	80
	5%	280	400"	260
Gulf of Mexico	95%	5	25	15
	50%	80	180	150
	5%	200	440	420
Offshore Pacific Coast	95%	3	95	70
	50%	60	210	170
	5%	125	410	310
Offshore Alaska	95%	0	120	110
	50%	0	430	350
	5%	100	1,070	850
TOTAL U.S. OFFSHORE	95%	90	550	440
	50%	230	1000	800
	5%	5005	1810	1430

Source: Arthur D. Little, Inc.

[1] At a wellhead price of $12/barrel

TABLE 6

ANNUAL GAS PRODUCTION LEVELS FROM
CONSOLIDATED OCS AREAS AT DIFFERENT CONFIDENCE LEVELS [1]
(billion cubic feet per year)

	Confidence Levels	Year of Production 1980	1985	1990
Offshore Atlantic Coast	95%	5	45	40
	50%	190	360	310
	5%	925	1,075	860
Gulf of Mexico	95%	340	700	560
	50%	1,100	1,700	1,350
	5%	2,260	3,250	2,700
Offshore Pacific Coast	95%	6	80	65
	50%	85	210	180
	5%	330	400	330
Offshore Alaska	95%	0	70	65
	50%	0	280	280
	5%	0	750	690
TOTAL U.S. OFFSHORE	95%	670	1500	1280
	50%	1590	2700	. 2280
	5%	2930	4500	3760

Source: Arthur D. Little, Inc.

[1] Assuming a wellhead price of $1.25/MCF

As shown in Tables 5 and 6, it is highly unlikely that new OCS oil and gas production, respectively, will exceed 500 million barrels and 3 trillion cubic feet in 1980, 1.81 billion barrels and 4.5 trillion cubic feet in 1985 and 1.43 billion barrels and 3.76 trillion cubic feet in 1990. However, it is very likely that annual oil and gas production from new areas, respectively, will exceed 90 million barrels and 0.67 trillion cubic feet in 1980, 550 million barrels and 1.51 trillion cubic feet in 1985 and 440 million barrels and 1.28 trillion cubic feet in 1990.

2. Expected Production Levels

The expected values or statistical mean of the probabilistic production forecasts as obtained under different price scenarios were used, firstly, to compare differences in attainable production levels between areas and, secondly, to assess the potential impact on the nation's oil and gas supply/demand balances.

The results, again for wellhead prices of $12./Bbl and $1.25/MCF, are shown in Table 7 for four major geographical areas.

The production scenarios developed for this study show that in 1985 about forty-eight percent of all new OCS oil may be produced offshore Alaska; fifteen percent, twenty and seventeen percent may be produced in areas, respectively, off the Atlantic Coast, in the Gulf of Mexico and off the Pacific Coast. This pattern may hold approximately until at least 1990.

New gas production, throughout the period considered, may be predominately from areas in the Gulf of Mexico; seventy-eight percent of all new OCS gas in 1980, seventy percent in 1985 and sixty-six percent in 1990.

Oil and gas production from new OCS areas are shown to decline after 1985 if leasing were to stop at the end of the 1975 Planning Schedule date, i.e., 1978, because the resources found on leased areas will start to become used up. However, production could be sustained if additional lease sales are held after 1978.

The total expected OCS oil and gas exploration and production results are shown in Figures 1 and 2. These figures show the expected annual and cumulative findings of oil and gas, respectively, the cumulative production streams, and the expected ultimate recoverable resources. About 50% of the ultimate recoverable OCS oil may be found as a result of BLM's proposed accelerated leasing program (13.2 billion barrels compared to an expected potential of 26 billion barrels). About 40% of the ultimate recoverable OCS gas resources may be found (39.4 trillion cubic feet compared to an expected potential of 98 trillion cubic feet).

For the purpose of the study we used the 1975 OCS Planning Schedule which ends in 1978; however, significant oil and gas finds are expected beyond 1978, and production five to seven years after discovery. In 1985, therefore, about 4.3 billion barrels of the 13.2 billion barrels of new

TABLE 7

EXPECTED PRODUCTION LEVELS FOR CRUDE OIL
IN BENCHMARK YEARS FROM CONSOLIDATED OCS AREAS
LEASED OR TO BE LEASED THROUGH 1978(1)
(million of barrels and billions of cubic feet per year)

	Type	Year of Production		
		1980	1985	1990
Offshore Atlantic Coast	oil	80	145	94
	Gas	220	340	283
Gulf of Mexico	oil	91	197	170
	Gas	1,109	1,692	1,370
Offshore Pacific Coast	oil	60	165	141
	Gas	93	180	151
Offshore Alaska	oil	8	465	396
	Gas	4	254	278
Total New U.S. Off*ore	Oil	239	972	801
	Gas	1,426	2,466	2,082

(1) At wellhead prices of $12/Bbl and $1.25/MCF.

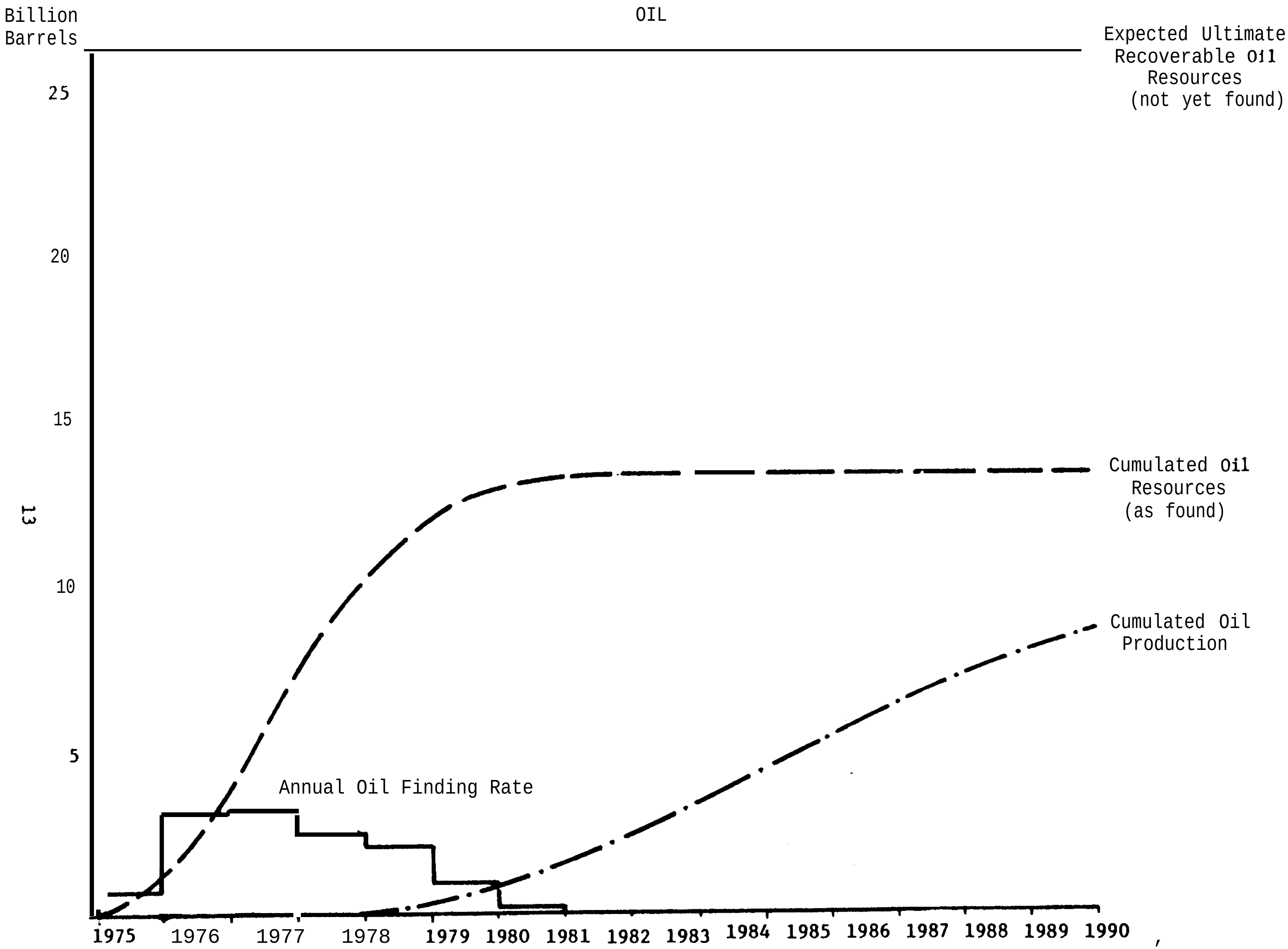


FIGURE 1 Expected OCS Oil Finding and Production History
1976 to 1990 for all U.S. OCS Areas
(**wellhead** price of $12/B)

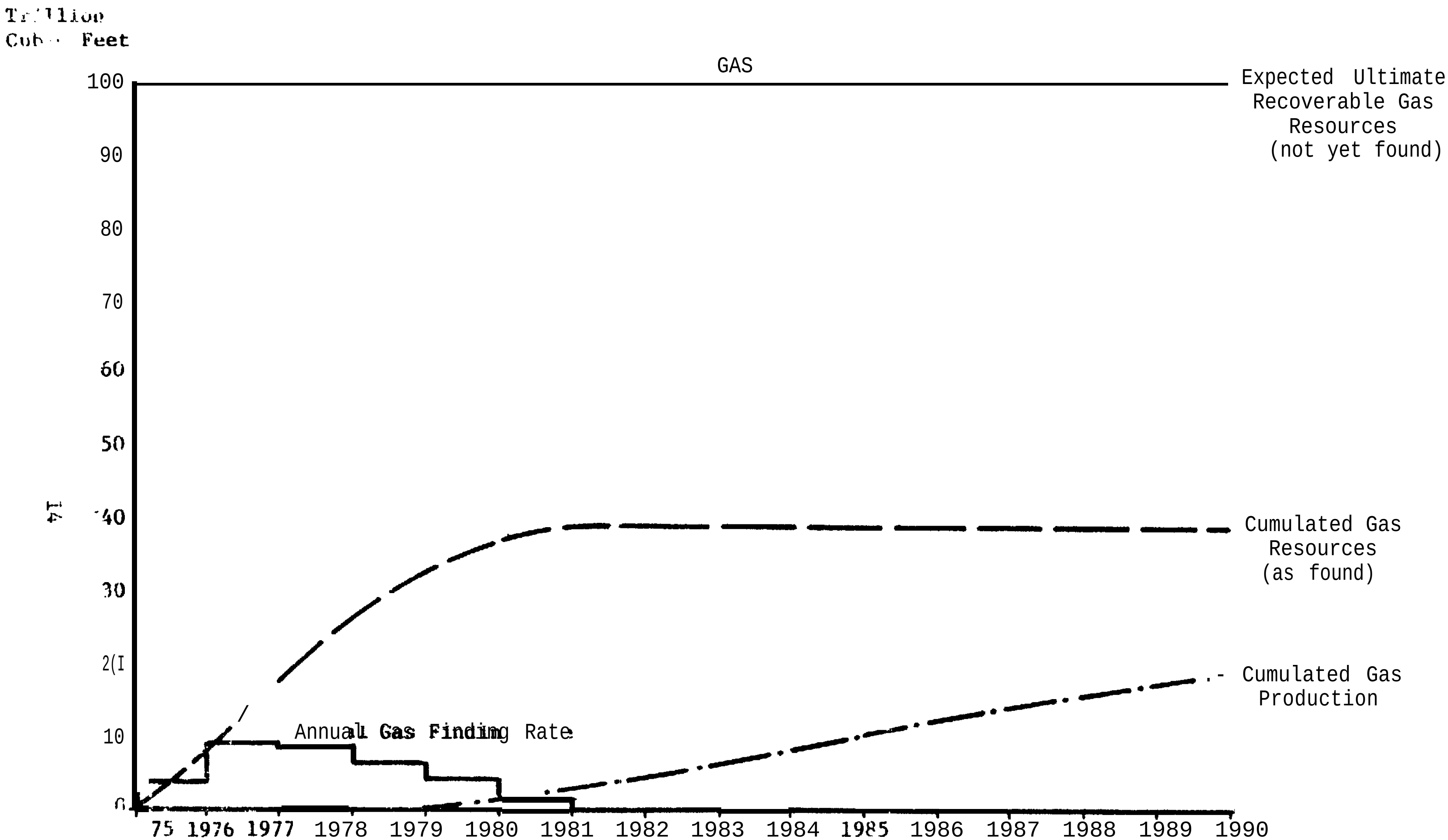


FIGURE 2 Expected OCS Gas Finding and Production History
1976 to 1990 for all U.S. OCS Areas
(wellhead price of $1.25 /MCF)

OCS oil which may have been found by then may have been produced. In 1990, 8.7 billion barrels of this 13.2 billion barrels may have been produced.

The cumulative gas production in 1985 may be 10 trillion cubic feet from the total of 39.4 trillion cubic feet found by that year. In 1990, 18.6 trillion cubic feet may have been produced, leaving 20.8 trillion cubic feet for future production.

E. IMPACT OF NEW OCS OIL AND GAS PRODUCTION

To assess the impact of new OCS oil and gas production, as found possible under the 1975 Planned Leasing Schedule, upon the nation's energy balance, we projected separate energy balances for oil and gas, with and without the new OCS oil and gas production streams. Two production scenarios were used to determine the range of impacts:

- An optimistic scenario based on high crude oil and natural gas production from onshore and existing offshore areas, with and without a high production stream from new OCS areas (corresponding to the expected production at wellhead prices of $12.00/barrel for oil and $1.25/MCF for gas).

- A pessimistic scenario based on low crude oil and natural gas production from onshore and existing offshore areas, with and without a low production stream from new OCS areas (corresponding to the expected production at wellhead prices of $4.50/barrel for oil and $0.75/MCF for gas).

Under the optimistic production forecast (see Table 8):

- Total oil and natural gas liquids production would increase from a level of 9.6 million barrels per day in 1975 to about 10 million barrels per day in 1980, 11.6 million barrels per day in 1985 and 12.3 million barrels per day in 1990 (see Table 8); the relative contribution of total domestic production from the offshore areas would grow from 17.5% in 1975 to 30% in 1985 and the focal point of the offshore production would have shifted from the Gulf of Mexico to the areas offshore off Alaska.

- Total associated and non-associated gas production would decrease from a level of 58.2 billion cubic feet per day in 1975 to about 50.6 billion cubic feet per day in 1980, to increase thereafter to 55.6 billion cubic feet per day in 1985 and 54.3 billion cubic feet per day in 1990; the relative contribution of total domestic production from offshore areas would grow from 21% in 1975 to 25% in 1985. The focal point of the offshore gas production would remain in the Gulf of Mexico area.

Under the pessimistic production forecast (see Tables 8 and 9):

- Total production of oil and natural gas liquids would slightly decrease from a level of 9.6 million barrels per day in 1975 to about 9.3 million barrels per day in 1980, 8.7 million barrels per day in 1985 and thereafter increase to 8.8 million barrels per day in 1990; the relative contribution of total offshore oil production would only increase from 17.5% in 1975 to about 19.5% in 1985; the focal point of offshore oil production would remain in the Gulf of Mexico.

- Total production of associated and non-associated gas would decrease significantly from a level of 58.2 billion cubic feet per day to 47.2 billion cubic feet per day in 1985 and 37.0 billion cubic feet per day in 1990; the relative contribution of total offshore production would grow from 21% In 1975 to about 25% in 1985 and the focal point of offshore gas production would remain in Gulf of Mexico.

For both the optimistic and pessimistic production scenarios total available U.S. onshore refining capacity was projected to grow at about 2% per year through 1980 and then remain constant between 1980 and 1990.

1. Impact of OCS Oil

The difference between utilized refinery capacity and domestic production is filled with crude oil imports. Oil from new OCS areas might reduce import requirements for crude oil by 10-15% in 1980 (pessimistic and optimistic supply scenarios, respectively) and by 10-30% in 1985 and 1990.

The fraction of utilized refinery capacity filled by new OCS oil production may amount to 4-6% under the pessimistic supply scenario and 6-14% under the optimistic supply scenario.

The largest impact of OCS oil production is expected to occur in the western seaboard and in Alaska. Refinery capacity in these two areas will have to grow at a rate of 2% per year between 1980 and 1990 under the pessimistic scenario. Available OCS oil in those combined refining centers might require as much as 75% more capacity in 1985 under the optimistic scenario.

2. Impact of OCS Gas

The impact of natural gas production from the OCS was estimated in terms of the changes which this production stream can make in alleviating otherwise expected curtailments in different demand sectors in the individual states. Three scenarios for distributing OCS and onshore [illegible]

TABLE 8

PROJECTIONS OF CRUDE 011. AND NATURAL GAS LIQUIDS PRODUCTION BY PRODUCING REGION

Optimistic Case (1)
(million barrels per day)

	YEAR				
	1974	1975	1980	1985	1990
Lower 48, old	8.67	7.92	5.89	4.24	3.38
Lower 48, new	0.00	0.00	0.71	1.9s	3.52
Gulf Of Mexico, old	1.36	1.23	0.88	0.33	0.30
Gulf of Mexico, new	0.00	0.00	0.36	0.71	0.60
Atlantic, new	0.00	0.00	0.24	0.43	0.29
Pacific, old	0.23	0.21	0.17	0.16	0.15
Pacific, new	0.00	0.00	0.27	0.49	0.50
Alaska onshore, new	0.03	0.08	1.37	1.92	2.47
Alaska offshore, old	0.16	0.15	0.09	0.0s	0.03
Alaska ocf-here, new	0.00	0.00	0.02	1.30	1.11
Total	10.45	9.59	10.00	11.61	12.35

Pessimistic Case (2)

	1974	1975	1980	19s5	1990
Lower 48, old	8.67	7.92	5.89	4.24	3.38
Lower 48, new	0.00	0.00	0.44	1.02	1.74
Gulf of Mexico, old	1.36	1.23	0.89	0.33	0.30
Gulf of Mexico, new	0.00	0.00	0.19	0.41	0.39
Atlantic, new	0.00	0.00	0.17	0.28	0.18
Pacific, old	0.23	0.21	0.18	0.16	0.15
Pacific, new	0.00	0.00	0.06	0.15	0.07
Alaska onshore, new	0.03	0.08	1.37	1.92	2.47
Alaska offshore, old	0.16	0.15	0.439	0.05	0.03
Alaska offshore, new	0.00	0.00	0.01	0.09	0.07
Total	10.45	9.s9	9.28	8.65	8.76

(1) Assumptions:

1. For onshore areas other than Alaska, annual discoveries will increase at a rate of 11% per year from 300 million barrels of recoverable reserves in 1974 to 950 million barrels in 1985 and they will decline thereafter;

2. Production from onshore areas of Alaska will be as shown, mainly reflecting increases in production from the Prudhoe Bay area;

3. Production from offshore reserves, producing in 1975 will continue to decline as shown;

4. For new OCS areas expected production will be as found possible with a $12/bbl wellhead price for oil and a $1.25/MCF wellhead price for gas assuming an accelerated lease sale schedule through 1978;

5. Extended oil recovery methods will start to contribute significantly to overall production between 1980 and 1985.

(2) Assumptions:

1. For onshore areas other than Alaska, annual discoveries will increase at a rate of only 3.52 per year from 300 million barrels of recoverable reserves in 1974 to 500 million barrels of recoverable reserves in 1990;

2. Production from onshore areas of Alaska will be as shown, reflecting mainly increases in production from the Prudhoe Bay area;

3. Production from offshore reserves, producing in 1975, will continue to decline as shown;

4. For new OCS area, expected production will be as found possible with a $4.50/bbl wellhead price for oil and a $0.75/MCF price for gas assuming an accelerated lease sale schedule through 1978;

5. Extended oil recovery methods will continue to contribute only marginally to overall production.

Source: Arthur D. Little, Inc., estimates.

TABLE 9

PROJECTIONS OF ASSOCIATED AND NON-ASSOCIATED NATURAL GAS PRODUCTION BY PRODUCING REGIONS

Optimistic Case (1)
(billions of cubic feet per day)

YEAR

	1974	1975	1980	1985	1990
Lower 48, old	49.30	46.11	30.88	21.07	12.49
Lower 48, new	0.00	0.00	6.71	16.12	27.26
Gulf of Mexico, old	12.53	11.40	7.75	5.03	1.87
Gulf of Mexico, new	0.00	0.00	3.24	5.07	4.13
Atlantic, new	0.00	0.00	0.74	1.25	0.96
Pacific, old	0.14	0.13	0.13	0.12	0.12
Pacific, new	0.00	0.00	0.54	1.03	0.77
Alaska onshore, new	0.34	0.34	0.34	4.00	5.48
Alaska offshore, old	0.24	0.22	0.16	0.11	0.08
Alaska offshore, new	0.00	0.00	0.03	1.19	1.17
Total	62.55	58.20	50.57	55.59	54.35

Pessimistic Case (2)

	1974	1975	1980	1985	1990
Lower 48, old	49.30	46.11	30.88	21.07	12.49
Lower 48, new	0.00	0.00	4.15	8.45	12.47
Gulf of Mexico, old	12.53	11.40	7.75	5.03	1.87
Gulf of Mexico, new	0.00	0.00	2.65	4.27	1.37
Atlantic, new	0.00	0.00	0.56	0.81	0.63
Pacific, old	0.14	0.13	0.13	0.12	0.12
Pacific, new	0.00	0.00	0.35	0.62	0.45
Alaska onshore, new	0.34	0.34	0.34	4.00	5.48
Alaska offshore, old	0.24	0.00	0.16	0.11	0.05
Alaska offshore, new	0.00	0.00	0.00	0.00	0.00
Total	62.55	58.20	47.2[illegible]	44.49	36.98

(1) Assumptions:

1. For onshore areas other than Alaska, annual discoveries will increase at a rate of 9% per year from 1.75 trillion cubic feet of recoverable reserves in 1974 to 3.9 trillion cubic feet in 1985, and they will decline thereafter;

2. Production from onshore areas of Alaska will be as shown, mainly reflecting increases in production from the Prudhoe Bay area.

3. Production from offshore reserves, producing in 1975 will continue to decline as shown;

4. For new OCS areas expected production will be as found possible with a $12/bbl wellhead price for oil and a $1.25 MCF wellhead price for gas assuming an accelerated lease sale schedule through 1978.

5. Extended oil recovery methods will start to contribute significantly to overall production between 1980 and 1985.

(2) Assumptions:

1. For onshore areas other than Alaska, annual discoveries will decrease at a rate of 1% per year from 1.75 trillion cubic feet of recoverable reserves in 1974 to 3.2 trillion cubic feet in 1990,

2. Production from onshore areas of Alaska will be as shown, reflecting mainly increases in production from the Prudhoe Bay area;

3. Production from offshore reserves, producing in 1975, will continue to decline as shown;

4. For a new OCS areas expected production will be as found possible with a $4.50/bbl wellhead price for oil and a $0.75/MCF wellhead price for gas assuming an accelerated lease sale schedule through 1983

5. Ext[illegible] will continue to contribute only ma[illegible] tion.

Source: Arthur D. Little, Inc., estimates.

among states were examined:

(1) All gas (onshore and OCS) will be distributed among states so that any shortfalls will be shared proportionally by all states ("national distribution");

(2) Onshore production will be retained by individual states to satisfy their own demand and OCS production and surplus state gas will be distributed nationally ("states' rights with national distribution");

(3) Onshore production will be retained by individual states to satisfy their own demand and OCS production and surplus state gas will be distributed regionally ("states' rights with regional distribution").

Under all three scenarios, in allocating available supplies over different end-use categories FPC's priority schedule was used, which gives highest priority to residential users, followed by commercial users, "other" users, industrial users and lastly electric utilities.

Demand was projected to grow at an annual rate of 0.2% until 1980, primarily because of a rapid decrease in electric utility demand, but at a rate of 1.8% between 1980 and 1985, and of 2.4% between 1985 and 1990.

The projections of total U.S. demand and supply from onshore and existing offshore areas are indicated in Table 10 which also shows the total and relative shortfalls in the target years. The total natural gas demand in 1980 is expected to be 18.7 trillion cubic feet per day. Total daily supply, without new OCS gas but including estimates for the supplemental sources of imports, coal gasification, synthetic natural gas and other sources, will range from 14.8 trillion cubic feet (pessimistic scenario) to 15.5 trillion cubic feet (optimistic scenario). This leads to potential shortfalls of 3.9 trillion cubic feet (21% of demand) in the pessimistic case and 3.2 trillion cubic feet (17% of demand) in the optimistic case. Natural gas from new OCS areas may alleviate the 1980 shortfalls by 30% in the pessimistic case and by 40% in the optimistic case.

In 1985, the shortfalls may be even less because of new OCS gas. In the pessimistic case the shortfall is expected to be reduced by 36% and in the optimistic case the shortfall may be eliminated altogether. In 1990 new OCS gas may reduce shortfalls by 20% in the pessimistic case and by 62% in the optimistic case.

It is expected that for the "national distribution" and the "states' rights with national distribution" scenarios, any gas supply shortfalls through 1990 will affect only the electric utility and industrial end-case sectors. The domestic, commercial and other demand sectors will not be affected, Consequently, regions such as New England where residential and commercial demand are a significant proportion of the

TABLE 10

TOTAL U.S. SHORTFALL IN NATURAL GAS SUPPLY
(trillions of cubic feet)

	1975	1980	1985	1990
Total U.S. Demand	18.6	18.7	20.5	23.1
<u>supply</u>				
Pessimistic without new OCS Case	18.0	14.8	16.0	15.7
Pessimistic Case with new OCS	18.0	15.8	17.6	17.0
Optimistic Base Case without new Ocs	18.0	15.5	18.4	20.0
Optimistic Case with new OCS	18.0	16.8	20.9	22.1
<u>Shortfall</u> - trillion cubic feet				
Pessimistic Base Case without new Ocs	.6	3.9	4.5	7.4
Pessimistic Case with new OCS	.6	2.9	2.9	6.1
Optimistic Base Case without new Ocs	.6	3.2	2.1	3.1
Optimistic Case with new OCS	.6	1.9	0.0	1.0
<u>Shortfall</u> - Percent				
Pessimistic Base Case without new Ocs	2.8	21.0	22.0	32.0
Pessimistic Case with new OCS	2.8	15.0	14.0	26.0
Optimistic Base Case without new Ocs	2.8	17.0	10.0	13.0
Optimistic Case with new OCS	2.8	10.0	0.0	4.4

Source: Arthur D. Little, Inc., estimates.

total demand will have a relatively small shortfall even if no new OCS gas production would be realized. For such regions the additional new OCS gas will reduce the shortfall significantly, possibly eliminating it completely. On the other hand, regions with a high proportion of industrial and electric utility gas usage, will experience a much smaller percentage reduction in their shortfall because of new OCS gas availability.

Under the "states' rights with regional distribution" scenario it was assumed that producing states would retain as much of their production as needed to satisfy demands. Any surplus plus the production from OCS areas would be distributed regionally in the nearest onshore region until regional demand was satisfied. This scenario would exacerbate regional differences in supply availability to the greatest degree. For instance, the West South Central region including Texas and Louisiana, would show little or no shortfall. The impact of new OCS gas production under this scenario will be greatest in those coastal regions, where onshore and existing offshore production is relatively small next to the new production streams expected from new offshore areas.

The "states' rights with national distribution" scenario would result in a more even allocation of any surplus production and the offshore production from federal waters, Regions such as New England with a larger proportion of residential and commercial demand would not be penalized for a lack of producing states as would be the case under the "states' rights with regional distribution" scenario.

Under this scenario the impact of new OCS gas in reducing shortfalls would be highest in regions lacking of producing states and relatively high proportional demand in the high priority end-use sectors, residential and commercial.

F. CAPITAL REQUIREMENTS FOR OCS EXPLORATION AND DEVELOPMENT*

The cumulative capital expenditures through 1990 for exploration and development for the OCS areas are expected to total $1~~4~~3.5 billion if the average prices are $12.00/Bbl for oil and $1.25/MCF for gas. The annual requirements under this price scenario can reach $2.7 billion (1980) which is significant compared to estimated 1974 industry investments of $5.7 billion for exploration and development in all areas. If a lower price scenario with its resulting lower activity levels is assumed ($4.50/Bbl for oil and $0.75/MCF for gas), the cumulative capital expenditures to 1990 are expected to be $4.5 billion with an expenditure of $0.7 billion in 1980. The annual expenditures in all cases are highest in 1980 and taper sharply afterwards to less than $0.2 billion in 1985 and to $0.02 billion in 1990. These projections are direct functions of BLM's Planned Leasing Schedule of 1975 which covers only the period through 1978. The cumulative capital expenditures for exploration and development are summarized in Table 11.

*Exclusive of capital requirements for lease bonus payments.

TABLE 11

CUMULATIVE CAPITAL EXPENDITURES THROUGH 1990 FOR EXPLORATION AND OIL AND GAS FIELD DEVELOPMENT IN CONSOLIDATED AREAS AT DIFFERENT CONFIDENCE LEVELS(1)
(in billions of 1975 dollars)

	Confidence Levels	Cumulative Expenditures	Expected Cumulative Expenditures
Offshore Atlantic Coast	95%	0.6	1.7
	50%	1.7	
	5%	4.2	
Gulf of Mexico	95%	2.4	4.7
	50%	4.5	
	5%	9.0	
Offshore Pacific Coast	95%	1.1	2.1
	50%	2.0	
	5%	3.8	
Offshore Alaska	95%	1.8	5.0
	50%	4.9	
	5%	10.9	
Total New U.S. Offshore	95%	8.9	13.5
	50%	13.9	
	5%	22.0	

(1) Assuming wellhead prices of $12/Bbl and $1.25/MCF.

In 1980, the expected annual capital requirements for the most likely price scenario ($12.00/barrel for oil and $1.25/MCF for gas) are $346 million for the Atlantic OCS, $795 million for the Gulf of Mexico, $430 million for the Pacific OCS, $562 million for the Southern Alaskan OCS and $560 million for the West and North Alaskan OCS. As shown in Table 11 the capital required for exploration and development will vary extensively for different levels of confidence. The total cumulated expenditures for exploration and oil and gas field development in new OCS areas to be leased through 1978 will very likely be more than 9 billion dollars (95% confidence level), but it will be quite unlikely that they will exceed 22 billion dollars (5% confidence level).

I. BACKGROUND

During the last few years, the United States has become increasingly concerned with its future energy sources in light of declining domestic production, increased demand for energy, environmental problems, the sharp increases in prices and the decrease in the security of supply of imported oil and gas. As a result, both government and private industry have been focusing upon finding possible new sources of energy. The promising U.S. Outer Continental Shelf (OCS) areas have been a major point of interest due to their high potential as a large source of oil and gas. To a large extent, OCS areas around all U.S. coastlines consist of sedimentary rocks of the general types in which oil and gas are normally found. As a result, oil and gas production may be possible from all the 17 areas Into which the U.S. OCS is divided with some yet unexplored areas being very likely to contain large amounts of commercially producible oil and gas. There are significant questions, however, with regard to which areas contain the best prospects, both with regard to the magnitude of attainable production streams and the landed costs of the available oil and gas. In addition, there are questions on the requirements of the capital which will be needed to find, develop and produce these resources.

The finding, development and production of oil and gas from the OCS in the United States is performed by the private sector; individual companies lease on individual blocks from the Federal Government the rights to perform these activities. The Bureau of Land Management (BLM) of the U.S. Department of Interior manages this leasing process and offers for lease selected, promising tracts that are nominated by private industry which has performed some geological and seismic exploration of the area. Leases are awarded through competitive bidding where the winning bid prices often directly reflect the perceived potential of a block and may account for significant fron-end investments of hundreds of millions of dollars for the rights to explore one block.

Since Federal OCS leasing began 22 years ago, about 13 million acres have been leased altogether, with by far the greater part of this acreage in the Gulf of Mexico.

The Federal Government received 609.6 million dollars in 1975 from royalties on oil and gas production on the Outer Continental Shelf, according to the Interior Department's U.S. Geological Survev. OCS royalties (597.2 million dollars of which is from tracts in the Gulf of Mexico and 12.4 million dollars from offshore California tracts) represents 69% of total royalties collected by the U.S. in 1975 for energy exploration and production on Federal lands. Offshore also represents 1812 leases, covering 8.4 million of the 101.4 million acres leased by the Federal Government for oil and gas production. In 1975, more than 13,500 producing leases are estimated to yield 593 million barrels of crude oil and natural gas liquids and 4.5 million MCF of marketed gas valued at more than 6.4 billion dollars. This yield represents 22.4% of the marketed gas and 16.2% of total crude and gas liquids produced in the U.S. during 1975.

OCS Economics and Costs

The process of exploration includes all the steps necessary to locate potential sources of petroleum and to establish their presence in commercial size accumulations. On the OCS, this may involve, among other activities, the drilling of one or more exploratory wells for each geophysical prospect. Exploratory expenditures for drilling in 200-meter water depths and in moderate climatic conditions, such as found in the Gulf of Mexico, may amount to approximately three million dollars for a 10,000-foot well. These are the purely technical costs incurred for exploratory well drilling. It should be recognized that these costs do not include other significant offshore exploratory expenditures such as lease bonuses, geological costs, and certain overhead expenditures that will normally be allocated to the exploratory effort.

As exploratory drilling progresses to greater water depths and to more severe climates, drilling expenditures will necessarily increase. The primary factors contributing to these increased expenditures are the rig capital costs and the drilling and equipping time involved.

The marked increase in costs as a function of water depth and climatic severity also apply to development and production expenditures. In water depths where sea floor producing units can be utilized, the cost of producing facilities is not expected to show a cost sensitivity to increasing water depths to the same extent as in the water depths range where platform-type installations can be employed. Of course, the distance from shore will continue to affect expenditures. In contrast with the exploration activity, which usually requires very few wells, the commercially successful offshore field requires a large number of development wells together with associated gathering, separating, storage and transportation facilities, including safety and environmental protection facilities. For the moderately severe climate, such as the Gulf of Mexico, and for water depths not exceeding 150 meters, the total cost for a development and production system can be estimated at approximately 125 to 150 million dollars for a 100 million-barrel oil field. In other words, this is a production system that will operate under the same conditions as an exploratory well that can be drilled for three million dollars. If climatic conditions become severe, such as can be found, for instance in the Gulf of Alaska and Lower Cook Inlet the costs for the same production system may be three times as much, i.e., in the range of 375 to 450 million dollars. Increased water depth, especially in areas with severe climatic conditions, may increase the costs as much as threefold, i.e., if the water depth is increased from 150 meters to 200 meters

Fox 75% ice-laden areas, drilling in deep open waters may be possible only during three-to-four months of the year. In areas with severe climatic conditions, platforms are not assumed economically feasible beyond 200-meter water depth and, therefore, floating/drilling, together with sea floor producing systems, are required. The cost of those producing systems will be substantially above the cost of systems in what is now considered severe climatic conditions and deep waters.

1. Objective of Study

The study was undertaken to support the Bureau of Land Management in its efforts to establish the potential of OCS oil and gas. The objectives of this study are to project the future oil and gas costs and production streams for all 17 OCS areas resulting from available resource estimates, technical cost projections and the currently scheduled lease sales. The implications of these production streams on the nation's supply-and-demand picture are examined for the target years 1980, 1985, and 1990. Also, the capital requirements for support of exploration, development and production are analyzed. The total U.S. OCS has been subdivided by BLM into 17 areas (Table III-l).

2. Methodological Approach

The main direction of the methodological approach is based upon the notion that production volumes, unit costs ($/barrel, $/MCF), development capital and time requirements are very sensitive to the size of individual fields encountered in the area under analysis. As a consequence, the analysis performed for this study projects the size and rate of fields found and developed each year as a function of the areas leased and the resulting exploration activities. For such an analysis to be valid, the technical costs for each required activity are assembled based upon the technology which is forecasted to be employed for a particular field size in a particular OCS area in a given year to produce annual cash flow streams associated with the ultimate production of a field. Since an OCS area may contain a number of fields, some of which are being developed and produced simultaneously, all costs and production streams are aggregated to allow projection of average values of unit costs and production volumes from an area. From the analysis, "minimum economic field sizes" are projected for the individual areas. When projecting the OCS costs, throughout this study, any economic rent in terms of lease costs was excluded to yield the minimum possible costs of oil and gas from the OCS.

There is considerable uncertainty associated with the total resources available from OCS areas, as well as with how these resources may be distributed over different sized individual fields. In order to project the total expected costs and production streams, a large number of equally likely scenarios were simulated of distributions of resource estimates, structure sizes, and the degree to which the structures are filled with hydrocarbons.

A data base was assembled from private industry sources on possible technologies and their costs, from government agencies and private organizations on supply-and-demand projections and past exploration experiences, and from U.S. Geological Survey on OCS resource projections.

The implications of new OCS production upon the national energy supply-and-demand situation have been analyzed separately for oil and gas. For both cases, a set of base scenarios were constructed for optimistic and conservative projections of production from onshore and existing OCS reserves and imports and for the supply and projections of demands. The triplications were examined in terms of changes in the satisfaction of demands as a result of the introduction of OCS oil and gas under different regulatory scenarios (for gas). The implications were performed for the target years of 1975, 1980, 1985, and 1990.

An economic assessment of the value of the OCS resource must take into account the time at which expenditures are made and production becomes available. Hence, the assessment must include projection of the industrial dynamics of the exploration and development process and must allow for the fact that companies, which are operating in a certain area, are competing for a limited number of men, materials and equipment.

There is some degree of uncertainty associated with most of the cost elements for exploration and development activities, all of which makes the overall prospecting and policy environment risky and difficult to manage.

In order to provide a suitable means for projecting impacts of alternate scenarios about this uncertain environment, ADL has developed a methodological framework to allow for:

- Inclusion of uncertainties surrounding the resource base estimates, assumed field-size distributions, unit equipment and operating costs, exploration and development durations, and inflation rates; and

- Presentation of the results of different assumptions about the availability of men, materials and equipment to sustain the exploration and development effort.

This adopted approach permits the assembling of aggregate cost estimates from the individual estimated costs. The individual estimates are made for physical equipment units, such as platforms, and production equipment and unit activities, such as the daily drilling contractor costs. Estimates, made for disaggregated cost elements, insure that cost differences, resulting from varying conditions, such as water depth in the case of platform costs can be specified separately for each of these physical units and unit activities. Further, disaggregation recognizes the variability in inflationary tendencies among cost elements. The result is an accurate estimate of aggregated costs. This approach further provides a basis for analyzing the sensitivity in production forecasts as a result of making different assumptions about potential recoverable reserves and field-size distribution. In addition, the ranges and likelihoods of occurrence of different important cost measures, as functions of specific production scenarios, have been analyzed with indication of how these costs will be different for different external conditions.

II. METHODOLOGY FOR PROJECTING OIL AND NATURAL GAS PRODUCTION AND COSTS FROM THE UNITED STATES OUTER CONTINENTAL SHELF

A OVERVIEW

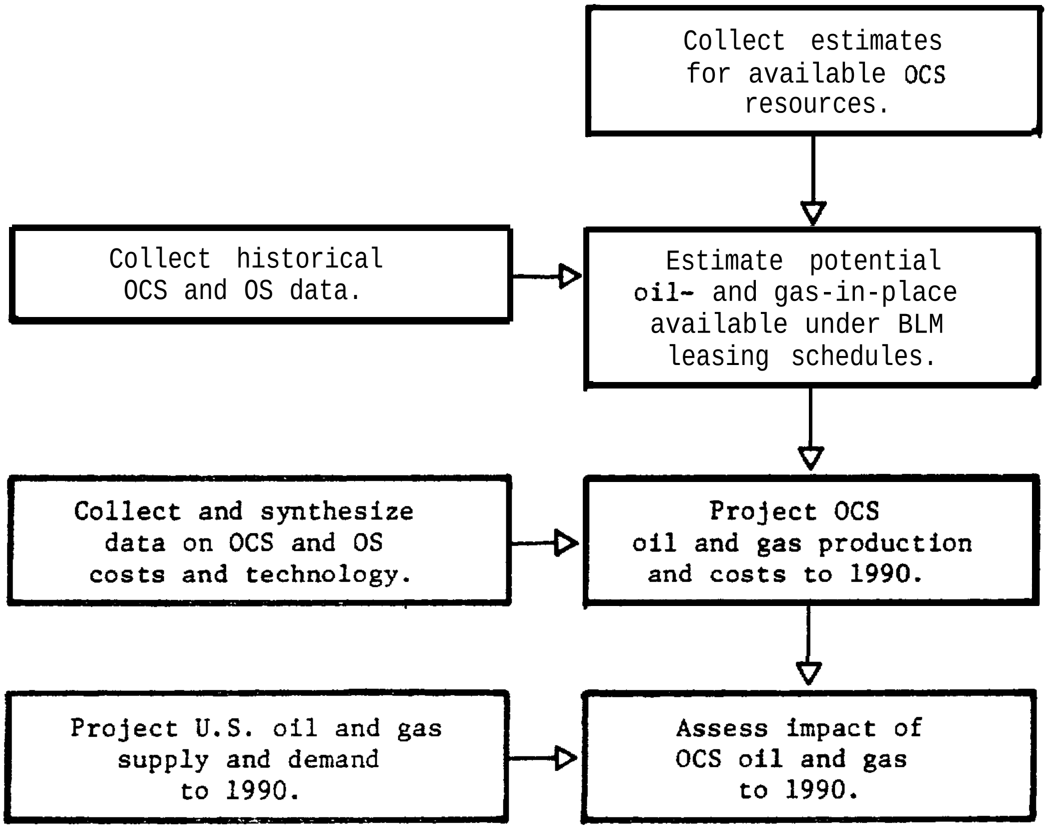
Only a relatively small part of the Outer Continental Shelf (OCS) of the United States has been explored and there is a high degree of uncertainty about the levels of oil and gas resources which might be present in the different remaining unexplored OCS areas, the distribution of these resources over different sized fields and the production characteristics of individual fields.

The basic approach of the selected methodology as discussed in this chapter for projecting production volumes and associated costs for areas is to project the total costs associated with *each individual field* on an annual basis associated with the resulting production streams. This approach has been chosen since the experience,' cost per unit of production is strongly coupled with the size, technology, and geographical context of *individual fields* and since it is expected that a wide range of oil and gas field sizes will be discovered and produced under a wide range of possible circumstances in each OCS area.

An overview of the analysis methodology and its information flow is presented in Figure 11.1.

The analysis is built around a set of computer-based models which:

- Simulate over a planning horizon beyond 1990 the dynamics of the exploration, development, and production process of an OCS area, in general, and each explored field, in particular, subject to equipment availability constraints;
- Build up accrued costs according to type of expenditures for each field;
- Project annual production of oil and gas of each field based upon its size and development program;
- Account for uncertainties by use of "Monte Carlo" simulation to simulate each OCS area a large number of times, each time with a different, equally likely scenario which is sampled from probability distributions by which the uncertain variables are expressed; and
- Project the U.S. total energy supply-and-demand balance by state with and without OCS oil and gas production for estimation of its impact.



Abbreviations: OCS = Outer Continental Shelf; OS = Off Shore

FIGURE 11.1 Overview of Methodology

B. THE PAPAMETERS OF THE PROBLEM

The major objective of this study is to project future oil and gas production and their associated costs on selected tracts of the U.S. Outer Continental Shelf. For these purposes, the following four sets of parameters have to be estimated:

1. An approximation of the *total resource base* of oil and gas in the general area of the specified tract and an estimate of the portion of this total resource base that may underlay the tract itself.

2. A definition of the *quality* of the resource base in terms of its expected field size distribution and in terms of its concurrent parameters of producibility of the trapped hydrocarbons, i.e., depths of producing horizons and well productivities.

3. A description of the physical *environment* of the tract as to prevailing weather conditions in its area , water depth, seasonal weather *patterns* and other *parameters* which are necessary *to* assess the type of technology required for exploration and field development.

4. Finally, an assessment of the *available technology* and of its cost for exploration, development, and production of the specified tract given its "quality" and its physical environment.

Although a correct analysis of potential production requires the determination of all the parameters indicated above, most of the values are not known with certainty. There are different levels of uncertainty associated with different parameters and therefore, a methodology has to be adopted to quantify the uncertainties and, subsequently, to aggregate the uncertain variables and parameters into estimates of production and production costs. As a consequence of the probabilistic (uncertain) nature of the input data, it can be expected that the projected production levels and costs will be equally uncertain and, hence that they, must be defined in a probabilistic sense.

Some parameters can be determined with a higher degree of confidence than others. The uncertainties present in the estimates of the quality of the resource base in terms of field size distributions and production characteristics of the fields itself are much larger than the uncertainties inherent in the estimates of exploration and development costs for specific tracts. To allow for this difference in levels of uncertainty, the following two-step approach was used in forecasting potential production levels and their associated costs in the 17 different OCS areas considered:

Step I: *Using* an aggregation procedure for probabilistically-defined information, determine expected production profiles.

Step II: In a deterministic sense, calculate the production cost of the specific tract under consideration.

Step I utilizes geological and oil industry information, including the uncertainty surrounding major variables, such as:

- the size of the area which can be expected to be leased by companies, i.e., a tentative definition of the area to be leased;
- the size of the total resource base;
- the expected field size distributions; and
- the exploration and development programs which companies can be expected to undertake.

Uncertainties inherent in estimates of the size of a resource base and of field size distributions are so large that they should be properly allowed for when used to derive projections of possible production levels. This was achieved by the use of the methodology of stochastic (or Monte Carlo)* simulation which allows for the aggregation of probability distributions of complex processes. The application of this methodology results in a probabilistic, rather than a deterministic, estimate of resulting oil and gas production from opening OCS areas to exploration and development. Coupled with the results of Step II an estimate can then be derived of how *much* capital may be required over future years to sustain these exploration and development efforts.

In order to be able to perform Step II, exploration, development and production costs have been developed for a certain field size, as a function of:

- the required technology,
- environmental parameters (water depth, distance-to-shore, etc.),
- the capital cost of the industry, and
- the fiscal regime of oil and gas production in the U.S.

These cost functions take the form of the example in Figure 11.2. It will be readily apparent that, under a given set of assumed parameter values, there is a minimum field size below which development becomes uneconomic under prevailing market prices for oil and gas. The determination of this "minimum economic field size" under current economic conditions and for the various areas of the OCS is an important result of this study. A more detailed description of the issue of minimum economic field size can be found in Section II.E.

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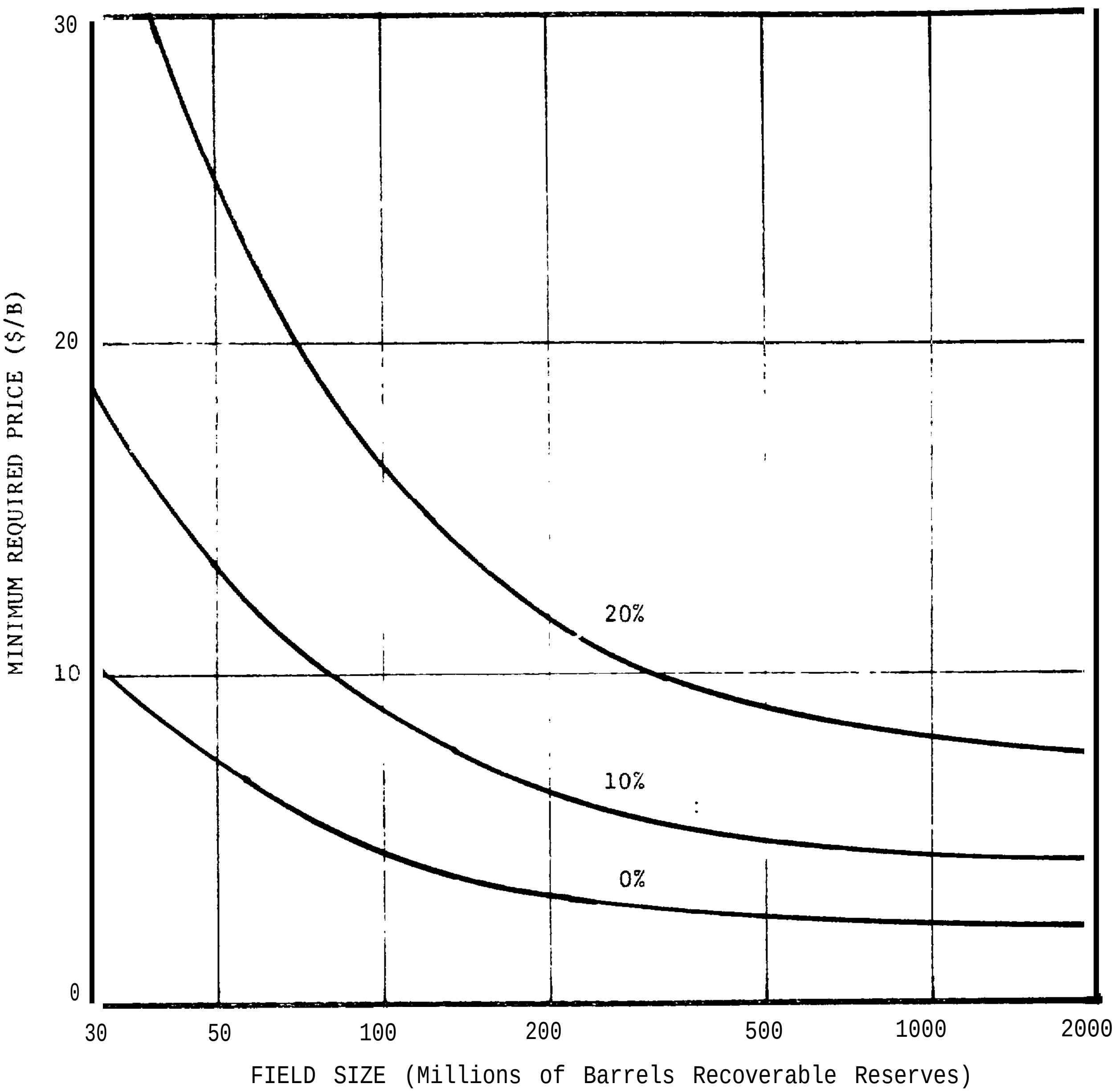
* For explanation of the technique of Monte Carlo simulation, the reader is referred to Hammersley, J. M. and Handscomb, D. C., *Monte Carlo Methods*, Methuen & Co. Ltd., London, Wiley, New york 1964.



Source: ~~Arthur D~~. Little, Inc., estimates.

FIGURE 11.2 Gulf of Alaska - 1975 Dollars

Minimum Required Price as a Function of Field Size - Oil (Average Well Productivity 2500 B/D)

Water Depth - 400 feet

Distance to Shore - 25 miles

Number of Years Delay - 5

Prices for oil and gas can change dramatically in the lapse of time between discovery of a new field and first production. This implies that companies will have to make their decision to go ahead and develop a newly-discovered field based on their projections of price and cost levels expected possibly as much as seven years hence. If they expect future prices in real terms to be higher or costs to be lower than at the time of discovery, those fields that are considered to be submarginal under existing price/cost conditions will still be developed. On the other hand, if companies expect future prices to be lower or costs to be higher than at the time of discovery, then fields might not be developed which would be economical to produce under present cost/price conditions. For the purposes of this study, projections have been made of probable future production levels under different cost/price scenarios to indicate the increase in production which can reasonably be expected at higher than current price levels.

C. RESOURCE ESTIMATIONS

In general, only part of all the oil and gas fields present in a particular area are made accessible for exploration drilling through a lease sale; private companies bid for rights to explore and produce on specific tracts. The bids may be based on good information obtained through seismic investigations about the presence of structures, but at the time of the bid no substantive information is available about the presence of oil or gas in the structures. The best a potential bidder can do is to assume the presence of oil and gas based on analogies with resource bases that have been developed already. Consequently, companies, in their bidding procedures, will first concentrate on so called structural traps, the presence of which they know through their seismic work. Secondly, companies will concentrate on the larger structures, since these hold promise for the largest fields. In this analysis the industry dynamics of exploration, development and production activities in offshore areas is simulated with allowance made for this particular aspect of offshore exploration in conjunction with the uncertainty of the geology of the resource base.

In order to simulate a particular exploration environment of a certain geographical area, e.g. the North Atlantic, estimates are needed of the total resource base which is expected to be present in the area and of the expected distribution of field sizes in that particular resource base.

One complete iteration in the simulation process for a certain geographic area is carried out as follows (see also Figure 11.3) in order to create our resource scenario:

1. Sample the distribution of expected total size of the resource base. This distribution reflects the uncertainties about the amount of oil and gas which may be present in an area. A typical distribution may take the form of the example in Figure 11-4 for oil. A similar distribution is available for gas. The result of this single sampling is the determination

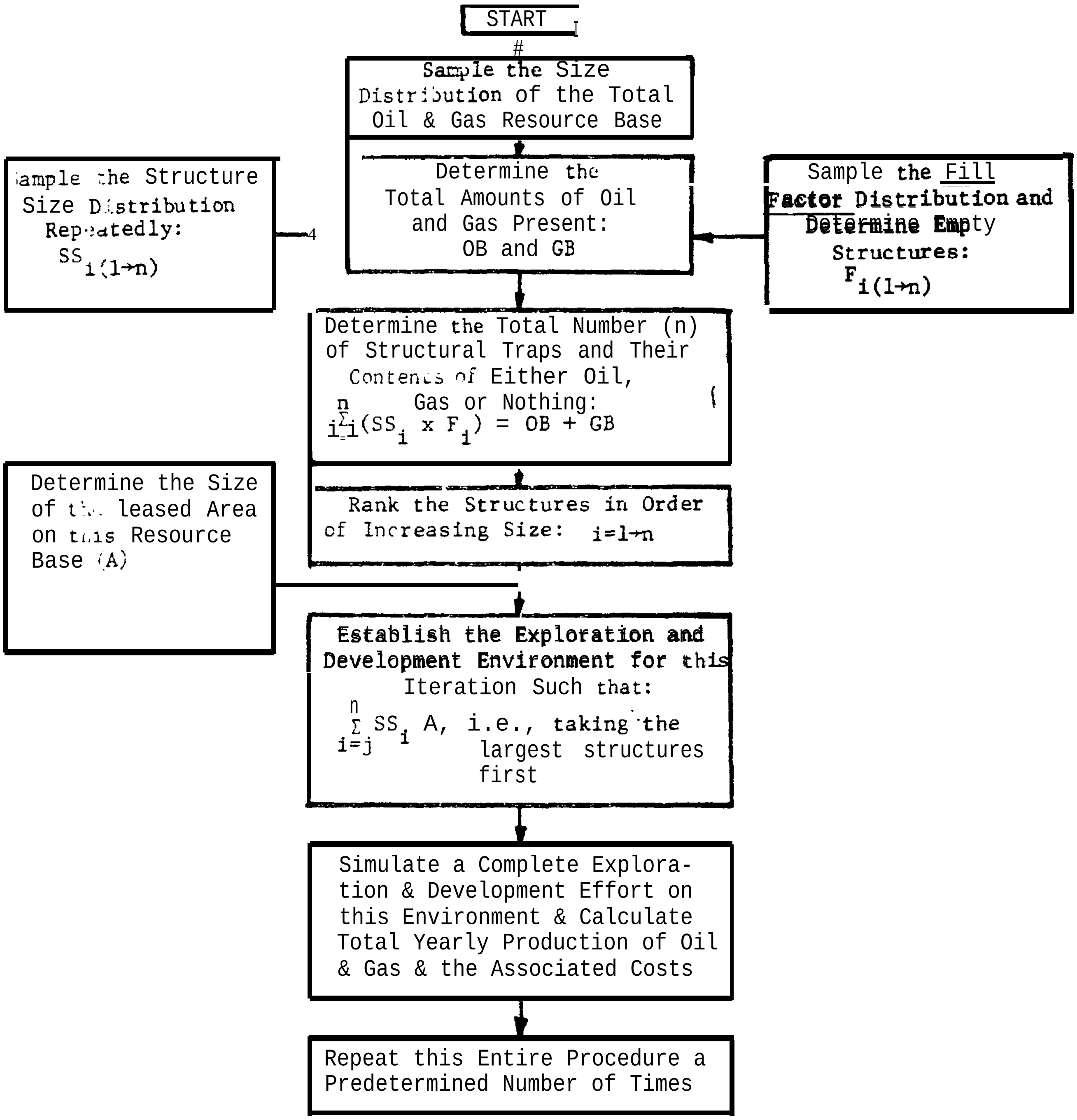


FIGURE 11.3 Simplified Flow Diagram of the Procedure to Simulate an Exploration and Development Environment in a Certain Geographic Area (one iteration)

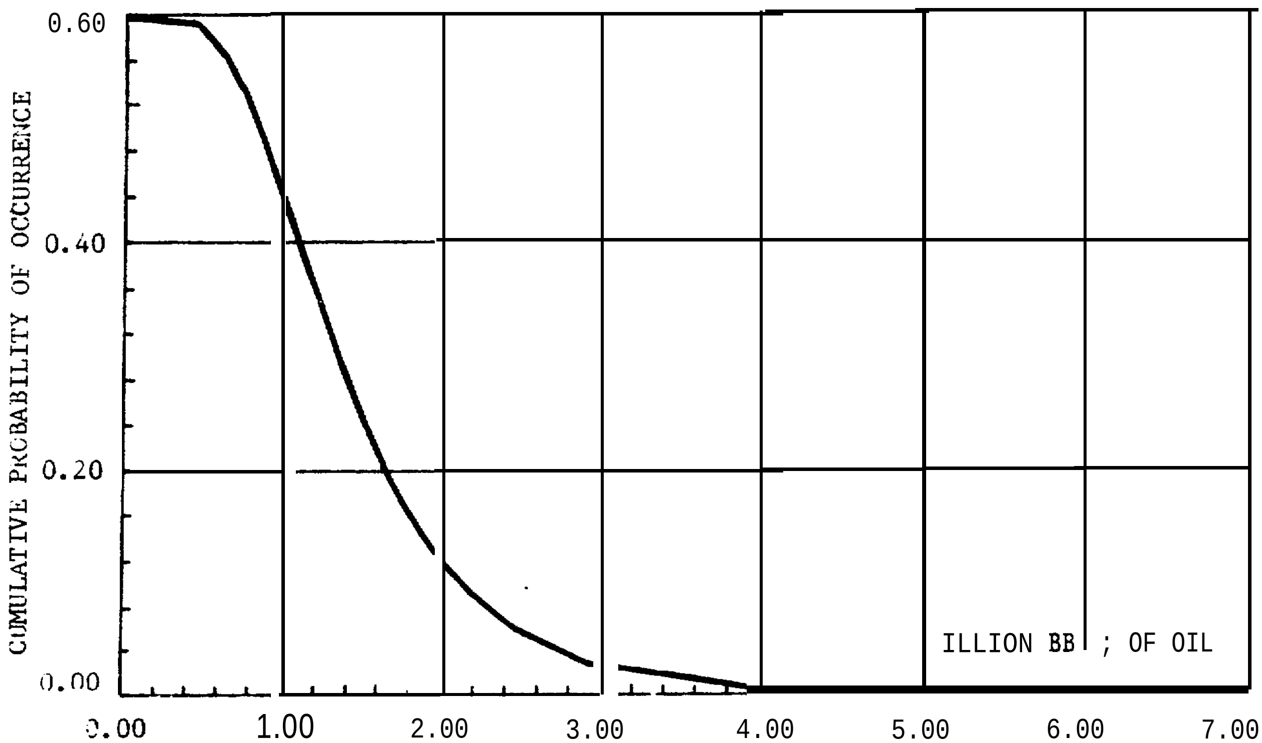


FIGURE 11.4 Probability Distribution of Occurrence of Undiscovered Recoverable Oil Resources in the North Atlantic Region of the Outer Continental Shelf (water depth 0-200m)

Source: U.S. Department of the Interior.

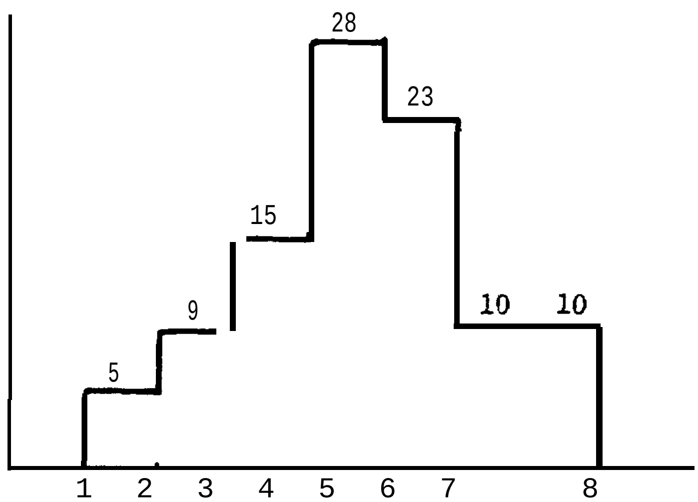
of the total amount of oil (and gas) present in the resource base for *this particular scenario*. The single sample is drawn at random but in such a fashion that the chance for a particular value to be drawn follows from the probability distribution as shown in Figure 11.4. Conversely, this implies that if many samples are drawn, in subsequent iterations, the total of all those samples will constitute a distribution such as the one in Figure 11.4, the probability distribution of the likely size of the total resource base for the area being analyzed.

2. The next step, ir, the process of building up one scenario of a complete exploration and development program for a certain area, is to allocate the previously determined oil and gas resource base over structural traps of different sizes which then contain either oil, gas or nothing. This is achieved by sampling the general structural trap size distribution as derived for this area using estimates for the average success ratios in terms of the number of dry versus successful exploratory wells and for the number of wells required to explore a structural trap of given size and complexity, the conditional probability of the particular trap being dry is then established. Through use of the Monte Carlo technique it is decided whether the trap is dry or not. If not dry then the amount of oil or gas present in the trap is obtained through sampling of a <u>fill-factor</u> distribution. Structures, if not dry, will be filled with oil or gas depencing on which of the two remaining resource bases is the largest. The <u>fill-factor</u> determines the average amount of recoverable oil and gas per unit area Present in the trap; i.e. it is a proxy for the-richness and recoverability of the oil or gas reservoir contained in the trap.

3. At this point the total number of structural traps present in the area have been determined, some of which hold the entire resource base in terms of recoverable oil and gas while others are dry. The actually leased area, though, contains usually only a fraction of the total resource base present in the general area. Hence, as a final step, the leased area is filled with structures, starting with the largest, some of which will contain oil or gas and some of which will be dry. The result is the establishment, through simulation, of a complete exploration and development environment scenario in the area under study and predicated upon the amount of resources assumed to be present in that area.

4. This environment will be subjected to an exploration and, eventually, to a development program. Total yearly production and the associated production costs will be calculated under various assumptions about the market price of oil and gas. The latter assumptions are necessary since total production of a lease is a function of the price to be obtained for the oil and gas. High prices will render high cost production of small fields economically viable, production that would not be obtained at lower market prices.

This particular iteration is finished with the calculation of production levels and costs. The parameters and results of the calculations are stored and the entire simulation procedure is repeated a large number of times to project the production streams and costs under equally probable scenarios. The results of all iterations are distributed according to frequencies of occurrence, e.g., as shown in Figure 11.5:



Total (cumulative) Production of Oil Obtained Within Each Scenario (billions of barrels)

FIGURE 11.5 Frequency Distribution of Cumulative Production from 100 Scenarios

Figure 11.5 can be interpreted as follows:

After a total of 100 iterations (100 scenarios), the calculation procedure obtained cumulative production levels between one and two billion barrels in five iterations, i.e., in 5% of the cases. It obtained levels of production between four and five billion barrels in 28 of the 100 iterations, i.e., in 28% of the cases. These results can also be expressed as, for instance, a chance of 28% to obtain production levels between four and five billion barrels, etc. Another way to express the results is in a cumulative sense, e.g., there is a 95% chance to obtain a production level of two billion barrels or less; there is an 86% chance [100 - (5 + 9] to obtain a level of three billion barrels or less, etc. This can graphically be shown as a cumulative distribution (Figure 11.6):

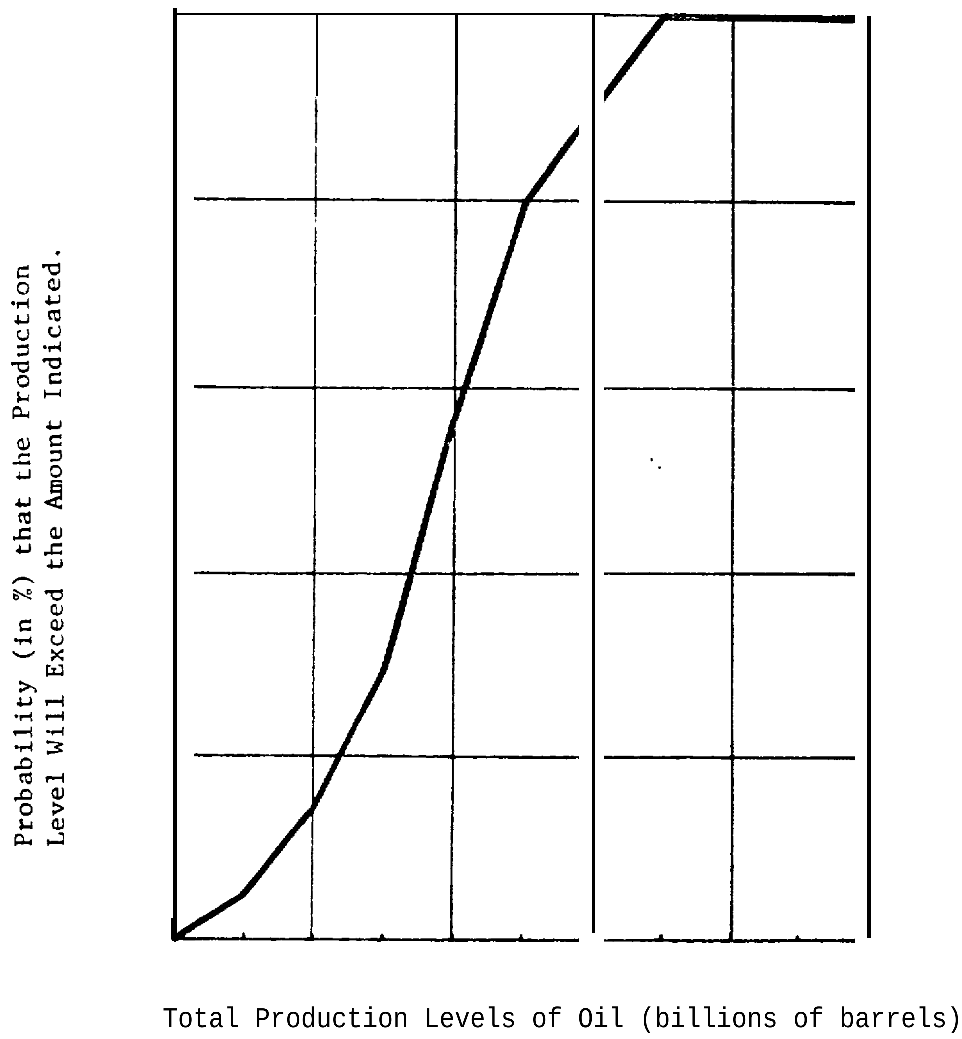


FIGURE 11.6 Cumulative Distribution of Total Production Levels which may be Expected from the Area

The production levels of *two* and three billion barrels in this example are also said to be the production of the 95% and 86% "confidence levels," respectively.

In the analysis itself, production and capital expenditure levels as might result from an acceleration lease sale schedule through 1978, are projected for the different OCS areas at confidence levels of 5%, 25%, 50%, 75% and 95%, respectively.

D. SIMULATION OF EXPLORATION AND DEVELOPMENT EFFORT

Once the exploration environment of the leased area has been defined in terms of a list of various-sized structural traps, each one of which is either filled with oil or gas or is empty, ADL's Basin Development Model is used to simulate the subsequent exploration and development effort. For this iteration, this simulation results in a determination of the expected value of total production and of total production costs at various price levels for oil in the U.S. market. Price level scenarios are a necessary condition for production and cost calculations since ultimate recovery depends upon the price obtained for the marginal barrel. As stated earlier, high prices will justify the recovery of high cost oil and thus will effectively increase total production of a given resource base; the reverse reasoning holds true for low prices.

A complete exploration and, if successful, a subsequent development effort are then simulated in the following chronological steps (see also Figure 11.7):

1. Take the largest structure off the list of structures underlying the area. Determine its distance to shore, the water depth at its location and the depth of the target formation.

2. Drill exploratory wells. The results of this drilling should help in the determination of whether the structure contains any commercially producible oil or gas or whether it is dry. The number of exploration wells to be drilled depend on:

   the size of the structure;

   the way of development of the structure, that is, whether it is developed *tract* by *tract* or whether companies owning the tract pool their exploration efforts. Pooled efforts usually result in a smaller number of exploratory wells, since information on them is exchanged;

   the ratio of the area containing reserves *to the* total area of the structure.

   Drilling of these exploration wells is constrained by the availability of exploration rigs in the total leased area in any year. Given estimates of how long it will take

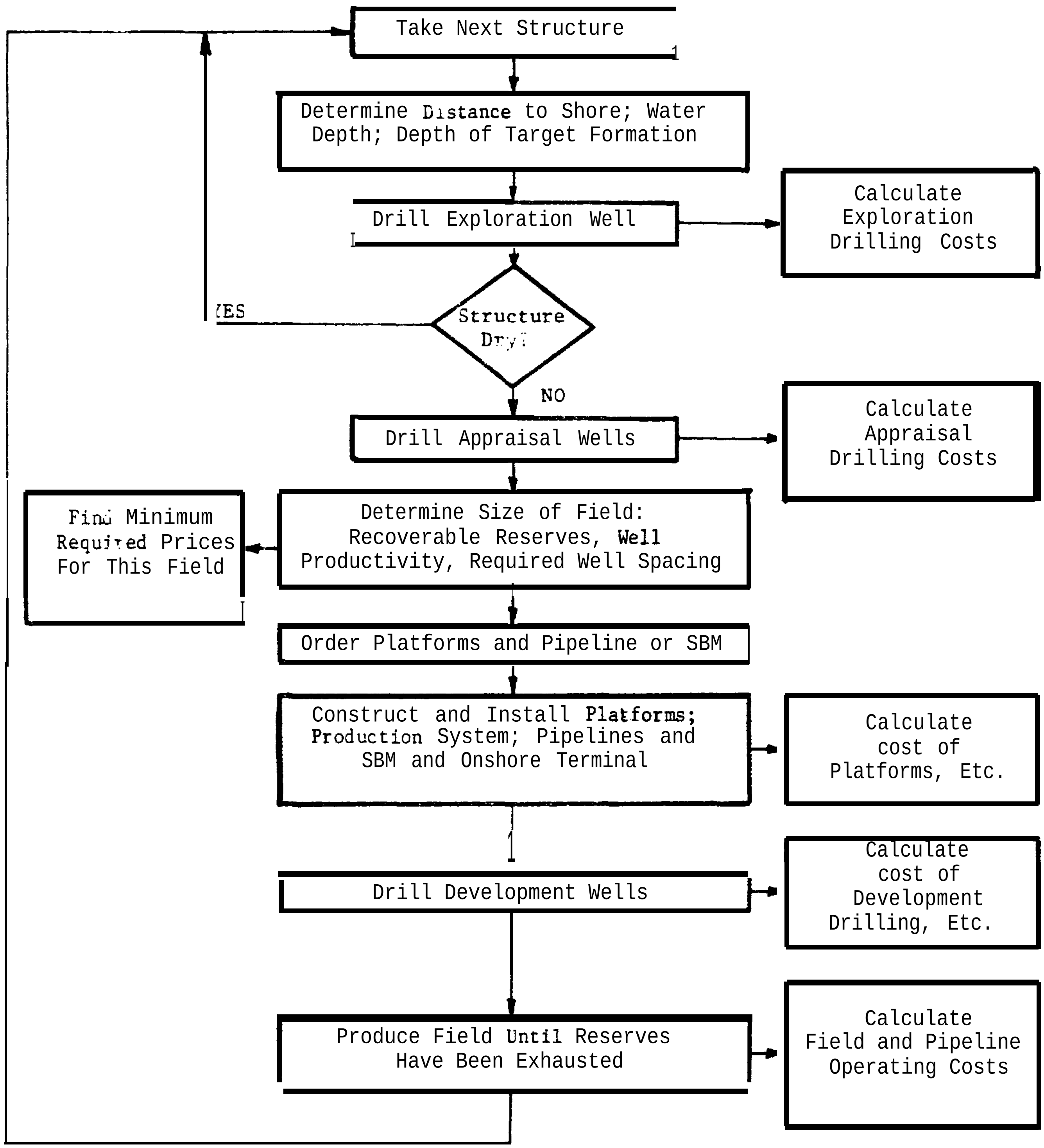


FIGURE 11.7 Simulation of the Exploration and Development Effort and Calculation of Associated Costs and Production for a Leased Area

drill an exploratory well in the area and how long the exploration drilling season is expected to be, the simulation will calculate how many years of exploration drilling will be required to completely explore the particular structure under analysis. The costs associated with the exploration drilling are calculated and stored for future use.

3. If the structure is dry, the next largest structure will be taken off the list of structures for the leased area and simulation of exploration drilling on this new structure will be done in exactly the same manner as described before. This implies that exploration on all structures in the leased area will start in the first year if enough rigs are present in the area to drill each of these structures. If not enough rigs are present in the area, then drilling will have to wait until drilling on other structures has been finished. In that case, the largest structures in the leased area are drilled first because the simulation selects them first, reflecting the fact that the industry shall want to know whether the largest structures in a leased area contain any oil or gas before spending their exploration dollars on the smaller structures which have a lower chance of containing economically producible oil or gas. If a predetermined number of successive structures is dry, the exploration effort in that area will be halted to reflect the fact that companies will not spend any more exploration dollars if the chances of finding oil or gas in remaining undrilled structures becomes increasingly small.

4. Subsequently, a number of appraisal wells are drilled, the timing of which depends upon rig availability similar to the timing of exploration drilling. Exploratory and appraisal drilling are done with the same type of rig. Appraisal drilling is performed on structures with proven reserves, aiming at delineating the field contours. Again, the costs associated with appraisal drilling are calcualted and stored for future use.

5. If the explored structure contains any oil or gas, the production characteristics in terms of the average well productivity, depth of producing formation, and well spacing required for development wells are specified. This specification can be based on average conditions of similar structures or on specific information available for the structure under consideration. The information on recoverable reserves, production characteristics, and location of the field is used to find the minimum required wellhead price for oil that will justify the development of this field. This is achieved by means of previously-determined functions* that relate

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*Determined through the minimum required price analysis (described under Section II.E).

PB 262 533

OUTER CONTINENTAL SHELF OIL AND GAS COSTS AND PRODUCTION VOLUME: THEIR IMPACT ON THE NATION'S ENERGY BALANCE TO 1990

report to

THE BUREAU OF LAND MANAGEMENT,
THE UNITED STATES
DEPARTMENT OF INTERIOR

CONTRACT NO. 08550 -CTS-48

submitted by

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JULY 1976

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16. Abstracts

The objectives of this study have been to determine the costs of finding and producing oil and gas in the OCS, estimate the quantities likely to be produced in 1980, 1985, and 1990 under various price scenarios, and estimate the potential regional and national impact on energy demand and supply. The estimates of potential oil and gas production from new OCS areas as presented in this report were based on the 1975 OCS Planning Schedule, which includes sales through 1978, and on the oil and gas resource estimates provided by the United States Geological Survey. The resource estimates for the Outer Continental Shelf provided by the USGS were for offshore areas with water not deeper than 600 feet.

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required price to field size for fields in certain geographical areas and of a certain "quality." Figure 11.8 shows an example of one of these functions with identification of the parameters governing the functions. Since each field has its own minimum wellhead price below which development is not economical, production and capital investments are categorized for each field into classes identified by their minimum wellhead price. Hence, production volume and costs are put into categories with wellhead prices, for instance, of $10/barrel or lower, $15/barrel or lower, $20/barrel or lower, etc.

6. After having simulated the drilling of appraisal wells to delineate the field contours, the procedure projects the number of development wells required to produce all the recoverable reserves of the field and the number of development platforms needed to accommodate processing facilities for the expected production of the field. The capacity of the transportation system to bring the production to shore and the size of the shore terminal is also then determined.

   In the case of vii, the transportation system can consist of a pipeline or a tanker loading facility. In the case of a pipeline, depending on the field size, the pipeline can be dedicated for this field alone if the field is very large, or for linking up the field production with a larger pipeline to shore accommodating production from different smaller sized fields. The simulation allows for the fact that pipeline and platform construction and installation usually takes more than one year. The number of platforms that can be constructed in any given year is limited by the number and capacity of construciton sites. The number of years required for appraisal and development of a field and the number of years between first discovery and first production are thus correctly simulated as being not only dependent on the location of the field, the size of the field, and the production characteristics but also on the assumed or expected availability of drilling rigs and platform construction sites.

   The costs associated with pipeline construction, with platform construction and installation, and with the construction of the gathering system linking up the different platforms in a field with the pipeline to shore are calculated separately by the procedure as these activities are simulated over time.

   It should be noted that production costs, as calculated at this point for a given field, are similar to the costs that were calculated at this point for a given field, are similar to the costs that were calculated to find the minimum economic wellhead price. However, the latter calculation was carried further into a complete cash flow analysis, taking into consideration the applicable tax burdens.

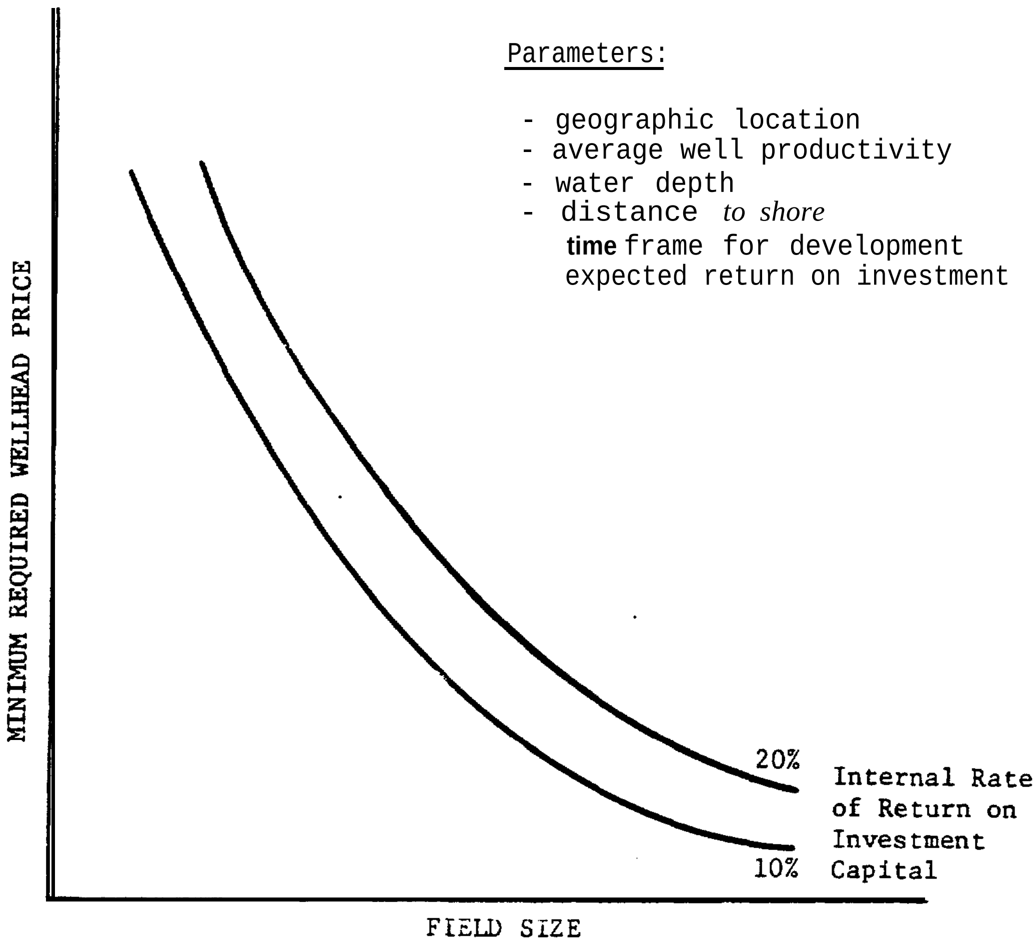


FIGURE II.8 Minimum Required Wellhead Price as a Function of Field Size (results from Minimum Required Price Analysis)

7. Once platforms are installed, development drilling can start. Again, it will take time until all development wells have been drilled from a platform. After development wells have been drilled for a given platform and the transportation system has been constructed, production from the field can begin. The total production profile for the field consists of the production profiles of the individual wells as they are brought into production after having been drilled. Operating costs associated with field production are also calculated and stored separately.

Once the simulation of exploration, appraisal, development, and production efforts for the given field has been finished and the associated costs and production profiles have teen calculated and saved, the next structure is selected from the list of structures expected to be present in the area under the present scenario and the entire simulation is repeated. This cycle will continue until the list of structures included in the leased area is completely exhausted.

' case several structures contain oil or gas, the simulation of the exploration, development, and production activities in the area will result in production and capital expenditure profiles over time for different minimum price categories. In other words, the procedure will have calculated how much annual oil and gas production and associated costs can be expected at different levels of future oil and gas prices if, indeed, the size of the resource base and its allocation over different sized structures is assumed in this particular iteration.

After a large number of iterations, the procedure will have developed a like number of production and capital expenditure profiles for each of the assumed price categories where the production and capital expenditure profiles will range from zero (if there is a chance that the area does not contain any oil or gas) to the highest production volume which might be possible if, indeed, the largest estimated amount of oil or gas will be present in the area.

E. MINIMUM REQUIRED PRICE

Some of the fields that might be found in the different Outer Continental Shelf areas considered in this analysis, if developed, will be profitable under the present cost/price conditions; other fields, especially the smaller ones, might not be profitable with present-day prices and costs. Besides, prices and costs may change relative to each other in the future.

Companies who decide to go ahead and develop a particular field in a particular area will base their decision on what they expect price/cost relationships, to be over the life of the field. The purpose of this study was not to try and make a forecast of what price/cost relationships for offshore field exploration and development can be expected to be. The purpose was to show which production levels could be expected if future prices assume certain prespecified values relative to the cost of exploration, development, and production. For this purpose, the Minimum Required Price concept has been used, the Mininum Required Price being that constant price over the life of the field at which field production will pay for the development and operating costs of the field with an allowance for royalty and tax payments and for the company's capital costs.

As shown in Figure 11.9, the Minimum Required Price is the breakeven price for which the present value of total yearly revenue (production x price) is equal to the present value of all outlays, i.e., exploration drilling costs, investment costs in field development and field operating costs, having allowed for royalties and tax payments. Thus, the Minimum Required Price is calculated as if companies would have perfect information about the size and quality of the field which they are going to find, the exploration drilling costs, and the development and production costs to be incurred to bring the field into production.

Companies make this type of calculation previous to a lease sale, when they have to decide to bid or not to bid on a particular block. In other words, if they find that the Minimum Required Price for the expected field size is higher than expected future price levels, they will most probably not bid on that particular block. If they find the Minimum Required Price for the expected field to be lower than estimated future price levels, they may bid on the block. Their maximum bid can be expected to be the difference between the Minimum Required Price as calculated and the perceived future oil price. In theory, society would thus reap the maximum economic rent. On the margin, where the Minimum Required Price as calculated for the expected field is equal to the estimated future price levels, they can be expected to bid with a zero cash bonus. The Minimum Required Price, therefore, allows for showing what the smallest field size is in a particular area which companies would be willing to look for at that price level.

Exploration costs were only nominally allowed for in the calculation of the Minimum Required Price. Costs included in the Minimum Required Price calculation were only costs required for field exploration, development and subsequent production as estimated to be necessary when making the bid/no bid decision prior to the lease sale. Expenditures which have already been made, i.e., the seismic and geophysical survey costs and the exploration drilling costs for dry blocks were not included. The latter expenditures can be regarded as a necessary cost of being in the oil business. The total return on capital has to be sufficiently high to repay these costs. Hence, it is the analyst's assumption on required returns which results in a more or less correct calculation of minimum required prices. The analysis is performed with various assumed rates of return, allowing some insight into the sensitivity of this variable.

A. WITHOUT INFLATION/DEFLATION

Step 1: $PV[(PRICE \times PROD) \times (1-TAX) \times (1-RYLTY)] =$

$PV(EXP_{tax}) + PV(DEV_{tax}) + PV(OC_{tax})$

Step 2: $$PRICE = \frac{PV(EXP_{tax}) + PV(DEV_{tax}) + PV(OC_{tax})}{PV[PROD \times (1-TAX) \times (1-RYLTY)]}$$

B. WITH INFLATION/DEFLATION

Step 1: $PV[(PRICE \times INFL \times PROD) \times (1-TAX) \times (1-RYLTY)] =$

$PV(EXP_{tax}) + PV(DEV_{tax}) + PV(OC_{tax})$

Step 2: $$PRICE = \frac{PV(EXP_{tax}) + PV(DEV_{tax}) + PV(OC_{tax})}{PV[PROD \times INFL \times (1-TAX) \times (1-RYLTY)]}$$

PV	=	Present value operator
PRICE	=	Minimum required price
PROD	=	Annual production
TAX	=	Tax rate
RYLTY	=	Royalty rate
EXP_{tax}	=	After tax exploration expenditures (having allowed for deductibles)
DEV_{tax}	=	After tax investment and expenditures in field development
OC_{tax}	=	After tax field production costs
INFL	=	Annual rate of change in PRICE relative to exploration, development and production costs

FIGURE 11.9 Calculating the Minimum Required Price (= Price)

Figure 11.10 shows a minimum required price schedule for the Gulf of Alaska. This schedule allows for an estimation of what the minimum economic field size will be if companies expect future prices to assume certain levels relative to the estimated field development and production costs. Using these price schedules, which were developed for the minimum economic field size analysis, the production for different sized fields plus the capital expenditures required for exploration and development of these fields under different price scenarios were categorized. This categorization was done on two levels (see Table II-l):

I The projections of future potential production levels and associated capital expenditures were grouped into classes of increasingly higher prices for oil and gas.

II Within each class the probability to reach certain levels is indicated by noting confidence levels between 5 and 95%.

F. PROJECTIONS OF FUTURE OIL AND GAS PRODUCTION FROM ONSHORE AREAS AND EXISTING OFFSHORE AREAS

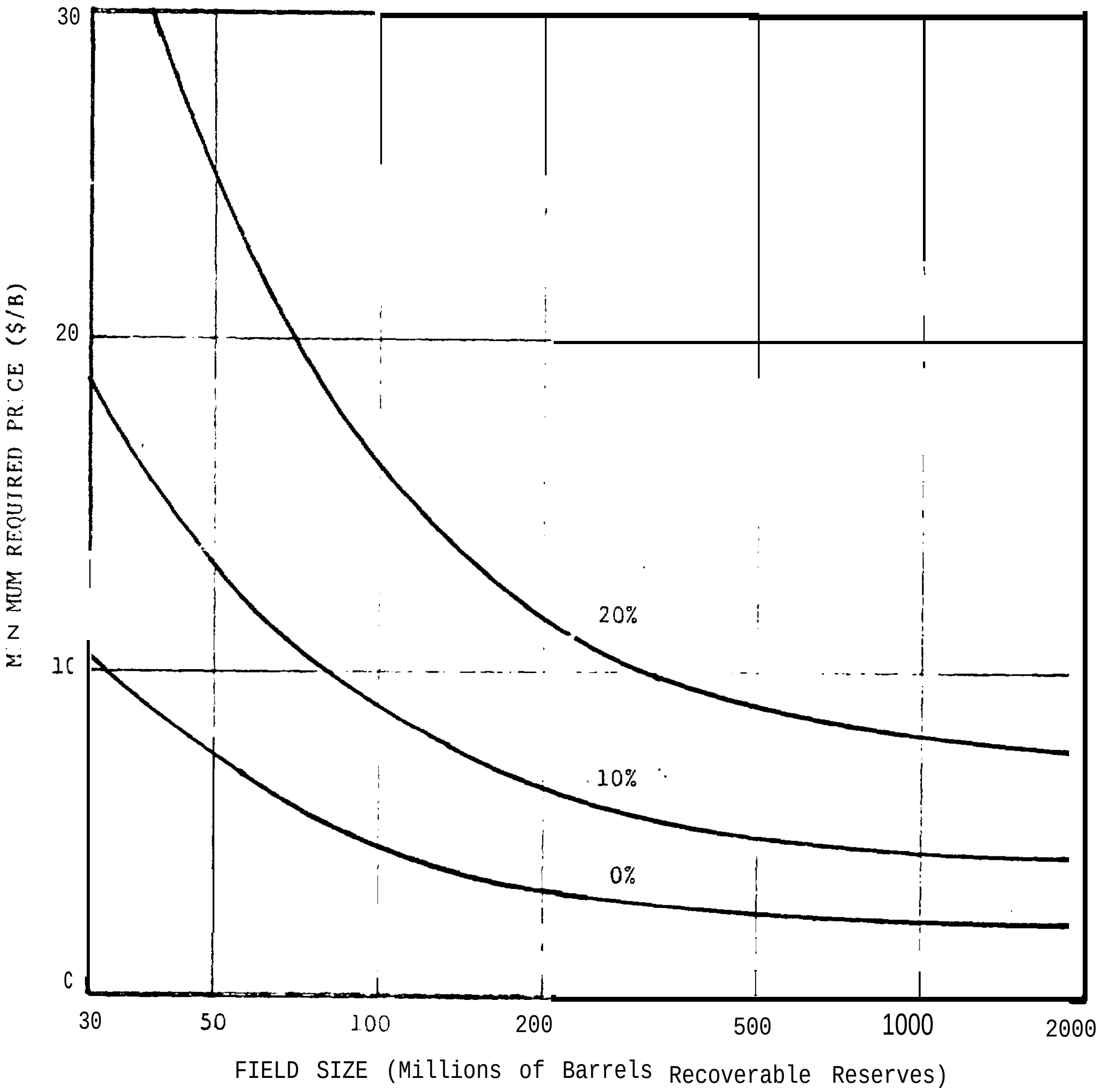
In order to assess the relative importance of expected production from new OCS areas a forecast was made of future potential production from onshore areas and from existing offshore areas at the state level.

For this purpose, mean values for estimated undiscovered recoverable resources for 75 petroleum provinces as obtained from the USGS were assigned to the individual states and a high and low projection was made of total production by projecting separately:

- Production from existing reserves;
- Production from reserves added through revisions and extensions to reserves existing in 1974;
- Production from newly discovered reserves; and
- Production from reserves resulting from extensions and revisions to newly discovered reserves.

An "optimistic" and a "pessimistic" production forecast was made in order to establish a range within which the actual future production levels can reasonably be expected to fall.

The optimistic production forecast was obtained assuming that economic incentives would result in-an increase in discovery rates relative to 1974 levels. Under that scenario half (50%) of the undiscovered resources were assumed to be discovered within the next 25 years, and all of the undiscovered resources were assumed to be discovered in the next 50 years.



Source: Arthur D. Little, Inc., estimates.

FIGURE 11.10 Gulf of Alaska - 1975 Dollars

Minimum Required Price as a Function of Field Size - Oil
(Average Well Productivity 2500 B/D)

Water Depth - 400 feet

Distance to Shore - 25 miles

Number of Years Delay - 5

TABLE II-1

EXPECTED OIL PRODUCTION OF THE EASTERN PART OF THE GULF OF ALASKA (MMB/DAY)

		1976	1980	1985	1990
Assumed Price: $4.50/Bbl					
Confidence level	5%	0	0	0	0
	25%	0	0	0	0
	50%	0	0	0	0
	75%	0	0	0	0
	95%	0	0	0	0
Assumed Price: $7/50/Bbl					
Confidence level	5%	0	0	359.28	258.02
	25%	0	0	80.88	60.38
	50%	0	0	0	0
	75%	0	0	0	0
	95%	0	"0	0	0
Assumed Price: $12.00/Bbl					
Confidence level	5%	0	0	391.72	284.56
	25%	0	0	102.80	71.56
	50%	0	0	35.34	26.34
	75%	0	0		
	95%	0	0		

The pessimistic production forecast resulted assuming that a lack of economic incentives would result in relatively low, future, **annual** discovery rates, remaining at approximately the same level as realized in 1974.

G FUTURE DOMESTIC CRUDE OIL AND NATURAL GAS LIQUIDS PRODUCTION AS A PERCENTAGE OF FUTURE REFINING CAPACITY

To assess the impact on the nations' energy **supply/demand** balance of the expected future *new* OCS oil and natural gas liquids projected by this analysis, it was estimated how much of the projected available refining capacity would be required to process these additional production streams in the major refining centers of the U.S.

Refining capacity utilization in 1974 for 16 different refining centers and the relative amounts of crude oil and natural gas liquids from different domestic producing areas used in these refining centers were obtained from Bureau of Mines Statistics.

Projections of future refining capacity up to and including 1980 for these 16 refining centers were made, allowing for planned new construction as reported in 1975/1976. Refining capacity for the years 1985 to 1990 were assumed to remain at the same level as found for 1980.

Domestic crude oil production as a percentage of refining capacity in the benchmark years 1980, 1985 and 1990 was calculated for an optimistic and pessimistic forecast of crude oil and natural gas liquids production for all the onshore and offshore areas in the United States, *inclusive and exclusive of production from new OCS areas*, assuming that refining centers would continue to use the same crude slate of domestic **crudes**, i.e., relative amounts of domestic crudes as used in 1974.

H. IMPACT OF OCS PRODUCTION ON U.S. NATURAL GAS CURTAILMENT POTENTIAL

In assessing the ability of OCS natural gas production to substantially alleviate anticipated shortfalls in natural gas supply, three scenarios of OCS *natural* gas distribution among states were examined *to* determine regional impacts of both added supplies from OCS areas and the manner in which these added supplies might be distributed. All scenarios follow the Federal Power Commission curtailment priorities in allocating available supplies first to residential and commercial users and lastly to industrial users and electric utilities.

The first scenario assumed that all natural gas - from onshore as well as OCS production, imports, and other supplemental sources - **would** be distributed among the states such that **any** shortfall in supply would be shared proportionately among all states. The other two scenarios assumed that producing states would retain as much of their onshore production needed to satisfy state demand; surplus onshore production, OCS production and other sources of natural gas would then be distributed nationally in one scenario and regionally in the other.

III. DATA BASE

A. GEOGRAPHIC INFORMATION

1. Outer Continental Shelf (OCS) Geographical Divisions

The Bureau of Land Management (BLM) of the United States Department of Interior has divided the Outer Continental Shelf (OCS) of the United States into 17 different geographic areas. These are presented in Table III-1 below.

TABLE III-1

OCS GEOGRAPHIC AREAS

OCS Area Number	Designation
1	North Atlantic
2	Mid-Atlantic
3	South Atlantic
4	MAFLA (Eastern Gulf of Mexico)
5	Central Gulf of Mexico
6	South Texas
7	Southern California
8	Santa Barbara Channel
9	Northern California
10	Washington - Oregon
11	Lower Cook Inlet
12	Gulf of Alaska
13	Scuthern Aleutian Arc
14	Bristol Bay Basin
15	Bering Sea
16	Chukchi Sea
17	Beaufort Sea

Throughout this analysis, Areas 5 and 6 (Central Gulf of Mexico and South Texas) have been consolidated since their oil and gas resources were estimated as one area by the USGS in the source material used for this study. The OCS areas have been consolidated into seven major areas for summary of production projections as shown in Table III-2.

TABLE III-2

CONSOLIDATION OF OCS AREAS FOR PRODUCTION SUMMARIES

Consolidated Area	OCS Area
Atlantic Coast	Areas 1, 2, and 3
Gulf of Mexico	Areas 4, 5, and 6
Pacific Coast	Areas 7, 8, 9, and 10
Gulf of Alaska	Areas 11, 12, and 13
Bering Sea	Areas 14, 15, and 16
Beaufort Sea	Area 17

2. OCS Geography

Based upon information published in the OCS Environmental Impact Statement* the locations of the most significant structures are known for the 17 OCS areas. The estimates of the water depth and distance to shore are given In Table III-3 for the seven consolidated OCS areas.

TABLE III-3

ESTIMATES OF EXPECTED WATER DEPTHS AND DISTANCES TO SHORE FOR CONSOLIDATED OCS AREAS

Consolidated OCS Area	Water Depth (feet)	Distance to Shore (miles)
1 Atlantic Coast	400	75
2 Gulf of Mexico	400	75
3 Pacific	600	15
4 Gulf of Alaska	400	25
5 Lower Cook Inlet and Bristol Bay	200	15
6 Bering and Chukchi Sea	200	75
7 Beaufort Sea	300	15

*United States Department of Interior: "Final Environmental Impact Statement Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf."

B. RESOURCE DEFINITION

Substantial work has been performed by the U.S. Department of the Interior on the estimation of undiscovered recoverable oil and gas resources in the United States. The results of that work have been presented in the Geological Survey Circular No. 725* which was prepared for the Federal Energy Administration in 1975. Estimates contained in Geological Survey Circular 725 are based on the expectations of geologists and geophysicists about the amounts of oil and gas that can be expected to be present in each different OCS area. These are made in a probabilistic sense, showing the chances that exist for different amounts of recoverable reserves of oil and gas to be present in the area.

Although the USGS specialists did assume that the resources would be present in structural traps and that they would be present in fields large enough to make recovery technologically and economically feasible, they did not include an assessment of the number and size of fields in these estimates, in spite of the fact that most of the areas considered for future exploration have already been explored through seismic surveys. The information contained in these surveys, however, is not available for public review because it is the basis for evaluation and bid decisions of the very companies that performed the surveys. In most of the areas, there is some indication of larger structures which are believed to be present. For instance, in the Gulf of Alaska a very large structure is reported to be present in the Icy Bay area and in the mid-Atlantic a structure of 72 square miles is believed to be present.

To a large degree the present study relies upon the source material for Circular 725 for its information on the likely probability distributions for the oil and gas resources of the OCS. These estimates were made through review of geological and geophysical information on more than 100 different petroleum provinces in the U.S. and by applying a subjective methodology for estimation of the resources of each potential petroleum province. These resource appraisals were based upon group assessments by geologists and geophysicists and upon the application of subjective probability estimates of the various parameters. Monte Carlo simulation was used to provide aggregate estimates of the sizes of the resource bases underlying the OCS 17 areas as defined by BLM.

Appendix A contains the 17 resource distributions of oil and of gas that pertain to the 17 Outer Continental Shelf areas as defined by the BLM and as used in this study.

A summary of the oil and gas resource estimates used is shown in Table III-4 for the 17 OCS areas in terms of their mean and subjective low and high estimates. The high estimate is specified at the 5% level

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*Geological Survey Circular 725, Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States, USGS 1975.

TABLE III-4

ESTIMATES OF UNDISCOVERED RECOVERABLE OIL AND GAS RESOURCES
UNITED STATES OFFSHORE AREAS

	(billions of barrels)			NATURAL GAS (trillions of cubic feet)		
Water Depths of 0-200 Meters (includes state and Federal lands)	95% Probability	5% Probability	Statistical Mean	95% Probability	5% Probability	Statistical Mean
1. North Atlantic	0	2.5	.9	0	13.1	4.4
2. Mid-Atlantic	0	4.6	1.8	0	14.2	5.3
3. South Atlantic	0	1.3	0,3	0	2.5	0.7
4. MAFLA (Eastern Gulf of Mexico)	0	2.7	1.0	0	2.8	1.0
5. Central Gulf of Mexico 6. South Texas	2.0	6.4	3.8	17.5	93.0	44.5
7. Southern California	0.4	2.1	1.1	0.4	2.1	1.1
8. Santa Barbara Channel	0.6	3.0	1.5	0.7	3.3	1.7
9. Northern California	0	0.8	0.3	0	0.8	0.3
10. Washington - Oregon	0	0.7	0.2	0	1.7	0.4
11. Lower Cook Inlet	0.5	2.4	1.2	1.0	4.5	2.4
12. Gulf of Alaska	0	4.7	1,4	0	14.0	4.1
13. Southern Aleutian Arc	0	0.2	0.04	0	0.5	01
14. Bristol Bay Basin	0	2.4	0.7	0	5.3	1.6
15. Bering Sea	0	7.0	2.2	0	15.0	5.1
16, Chukchi Sea	0	14.5	6.4	0	38.8	17.5
17. Beaufort Sea	0	7.6	3.3	0	19.3	8.2
TOTAL OCS			26.14			98.4

Source: USGS estimates.

of confidence, i.e., there is only a 5% (1 in 20) likelihood that the actual resources, when found, will exceed the high estimate. The low estimate is specified at the 95% level of confidence, i.e., there is a 95% (19 in 20) likelihood that the actual resources, when found, will exceed the low estimate.

2. Field Size Distribution

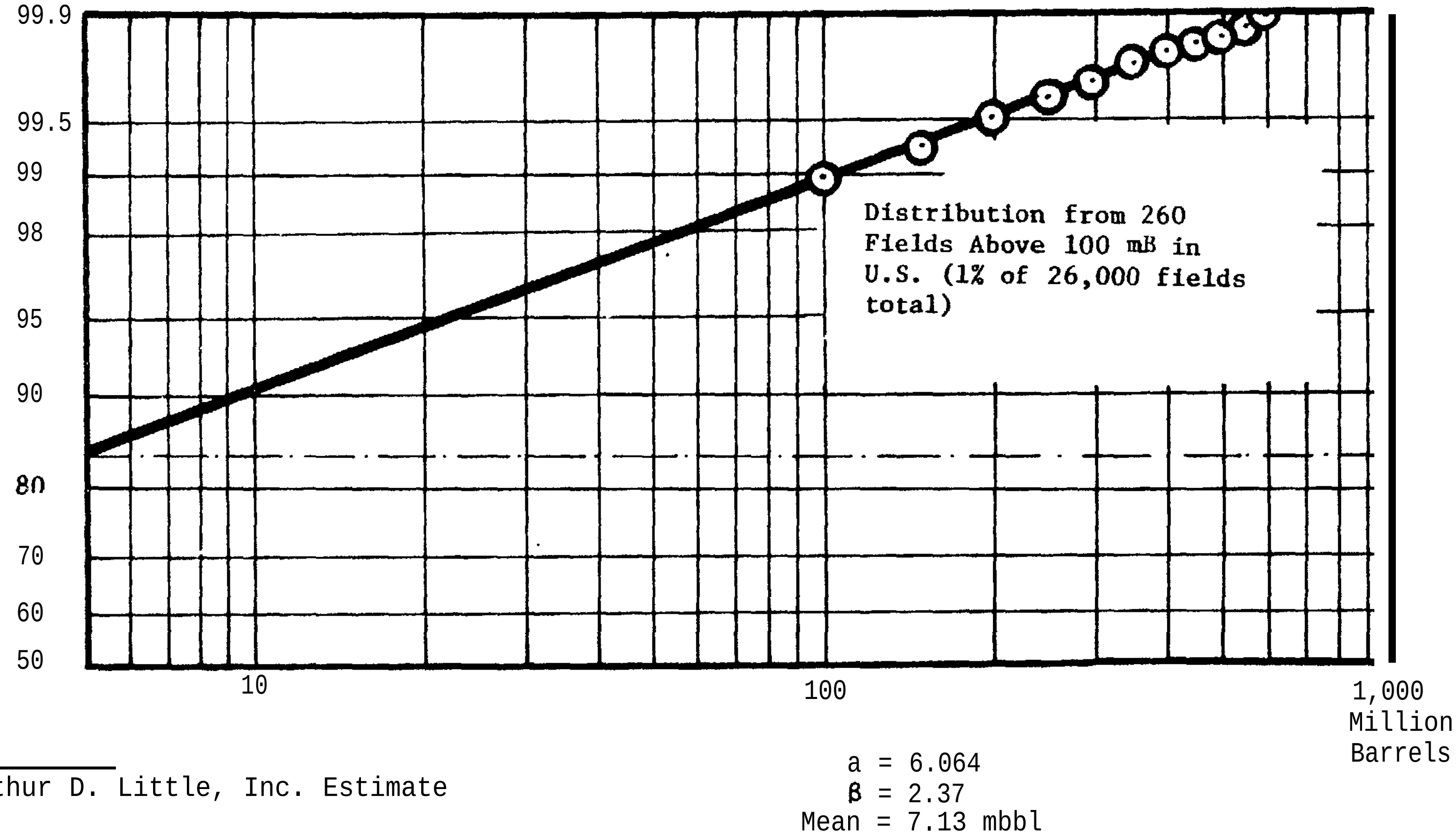
Since no explicit information is available on field size distributions in the new OCS areas, and since it is questionable if new areas will have distributions which may be similar to analog areas or areas with similar geology, it was assumed that field size distributions in new areas could be approximated by the empirical U.S. average field size distribution for oil and gas fields. Figure 111.1 shows the distribution of field sizes of the hitherto discovered fields in the United States. Since fields smaller than 5 million barrels (oil equivalent) in all cases may not be considered commercial on the OCS, a truncated distribution has been used for the different OCS areas. Only the top 15% of the possible field sizes shown in Figure 111.1 will be developed on the OCS since all smaller field sizes are below the minimum economic field size under present cost/price relationships.

3. Fill Factor Distribution

Oil and gas fields have different fill factors in terms of the average number of recoverable barrels of oil per acre or average number of recoverable cubic feet of gas per acre. In absence of knowledge of the specific fill factors which may be expected in a particular unexplored OCS area, the U.S. average fill factor distribution for giant fields has been selected as a best estimate of the distribution of the fill factor of OCS commercial fields. This distribution Is presented on log-normal probability paper in Figure 111.2. The mean of this distribution is 56,750 bbls/acre and it has a standard deviation of the log-normal distribution of 1.344 under the assumption that it is log-normally distributed.

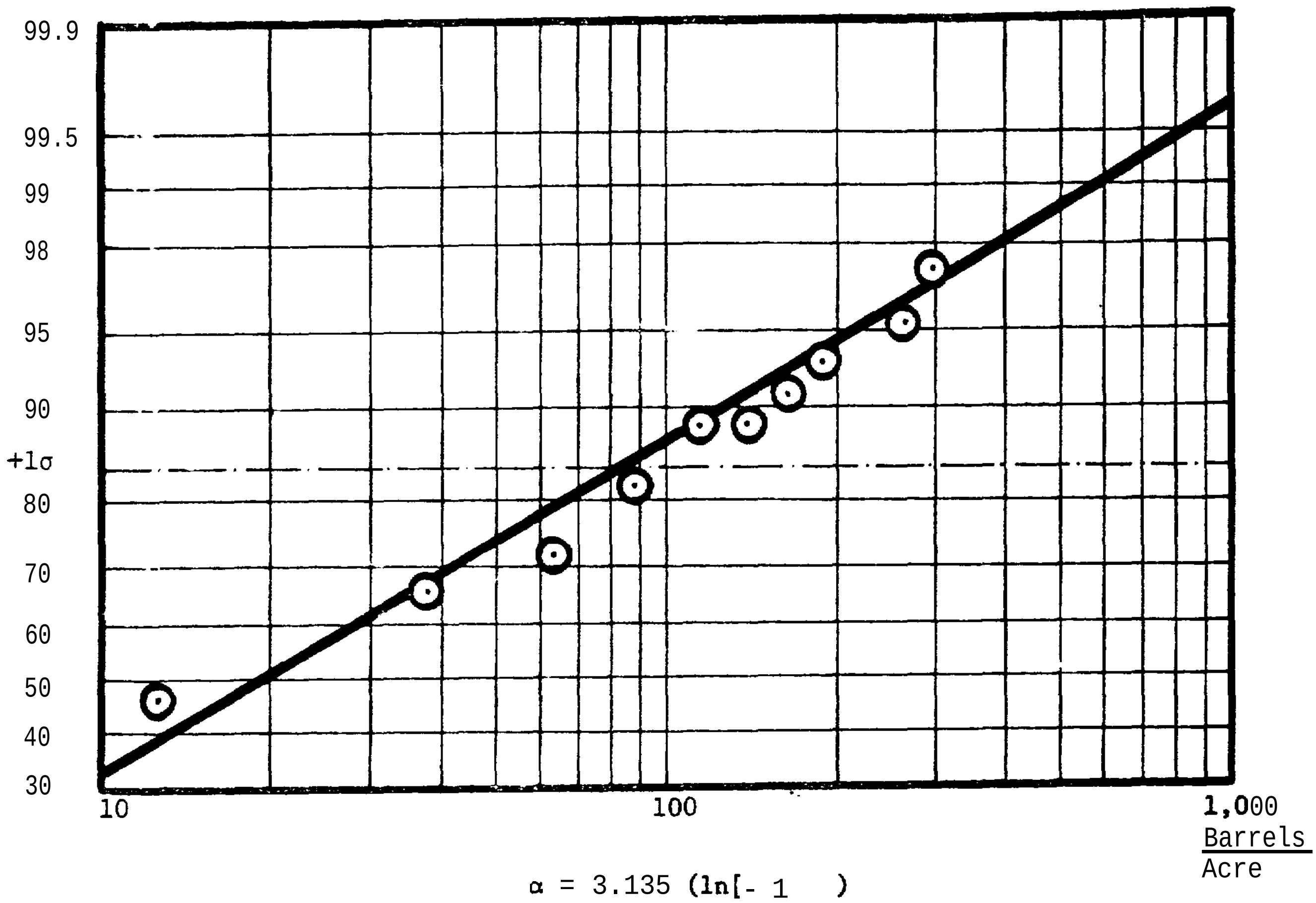
4. Structure Size Distribution

The distribution of structure sizes (in acres) is not publically known for the larger fields of the unexplored OCS areas. An average structure size distribution has been derived from the U.S. average field size distribution (Figure 111.1) to serve as the basis for the present analysis and the U.S. average fill factor distribution (Figure 11.2) under the assumption that both of these distributions are log-normal. The resulting log-normal distribution is shown in Figure 111.3. The imputed structure size distribution has a mean of 31.2 acres and a standard deviation of the log normal distribution is 1.013. The particular distributions for the structural traps which have been used for the individual areas are given in Table III-5. They have been based on the minimum economic field sizes as established for the different areas in this analysis.



Source: Arthur D. Little, Inc. Estimate

FIGURE 111.1 **Lognormal** Distribution of U.S. Oil Field Sizes



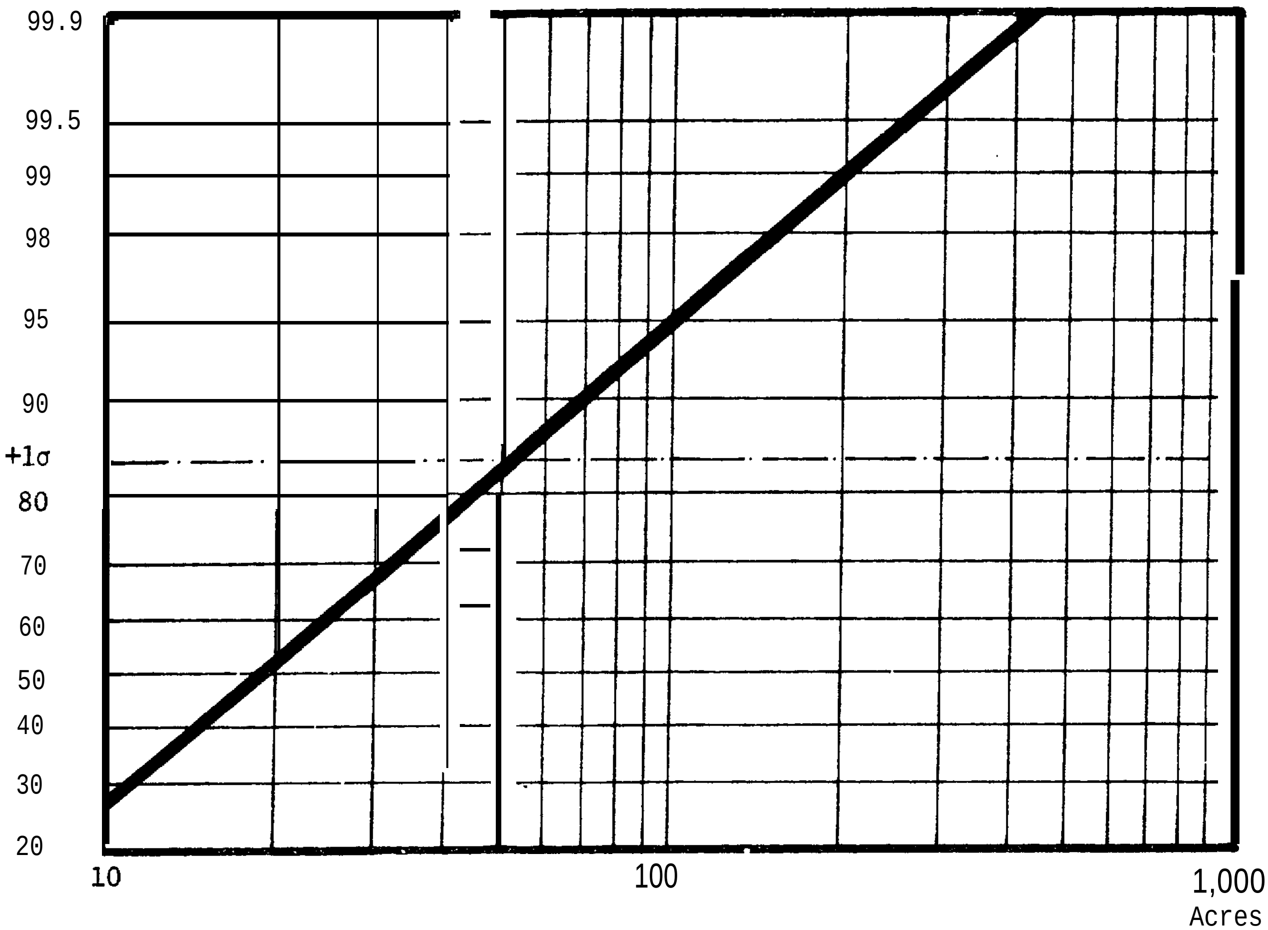
α = 3.135 (ln[- 1)

β = 1.344

Mean = 56.75 $\frac{\text{k bbl}}{\text{acre}}$

FIGURE III.2 Fill Distribution

Source: Arthur D. Little, Inc., estimates.



u = 2.93
β = 1.013
Mean = 31.20 acres

FIGURE III.3 U.S. Average Structure Size "Distribution

Source: Arthur D. Little, Inc., estimates.

SIZE DISTRIBUTION OF STRUCTURAL TRAPS AS USED FOR AREA SIMULATIONS[1]

(In square miles of surface area)

Area names	Cumulative Percentiles								
	0.	1.	5.	25.	50.	75.	95.	99.	100.
1. Atlantic, Gulf of Mexico, Pacific	0.14	0.58	1.10	2.67	5.09	9.36	23.40	45.43	413.0
2. Alaska Offshore[2]	0.69	2.42	3.85	7.85	12.94	20.65	41.30	68.87	413.0
3. Beaufort Sea	0.96	4.54	6.88	12.66	19.27	28.91	55.07	82.60	413.0

[1]Assuming a minimum economic field size of 5 million barrels for the Gulf of Mexico, the Atlantic, and the Pacific, 15 million barrles for all ares south and west off the coast of Alaska, and 50 million barrels for the Beaufort Sea.

[2]Gulf of Alaska, Lower Cook Inlet, Bristol Bay, Bering Sea, Chukchi Sea.

Source: Arthur D. Little, Inc., estimates.

C. COST DATA

All costs in this study are presented in 1975 dollars except where otherwise specified. The cost data base was developed from interviews with independent individuals and company representatives both in the United States and abroad. In addition, a literature survey was performed. The resulting data base contains estimates of all investment and operating costs from early seismic exploration activity up to delivery of offshore oil and gas at shore based receiving facilities.

To allow for the wide range of different conditions which can be expected in the 17 different OCS areas it has been necessary to develop the costs at a level of detail where changes in these costs, because of contextual changes, could be allowed for properly. Consequently, this required the data items to be parametrized based upon our understanding of the engineering considerations and concepts on which the present day offshore technology is based.

Apart from Upper Cook Inlet, none of the OCS areas of Alaska has had any offshore field development. The special circumstances, such as the extreme cold and harsh weather conditions, and other hazards not yet encountered in known areas, such as floating icebergs or moving ice fields, will require new platform designs and improved field development technology. The costs of this improved technology, as used in this study, could only be estimated by extrapolation of the costs of known technology as applied in areas with harsh conditions such as the North Sea. For this reason, the estimates which are presented here should only be taken for 'what they pretend to be: *educated guesses of what it may cost to explore for and develop oil and gas fields in these new unknown areas,*

Exploration costs are broadly defined as all costs incurred before the actual discovery of commercial oil or gas in a field. Development costs are all costs incurred to delineate a field and to install equipment and facilities necessary for production of that field including any transportation facilities and receiving terminals required to bring the oil and/or gas onshore. Operating costs or production costs are costs directly related with the production and transportation to shore of the oil and gas.

Only seven of the 17 OCS areas, which have been analyzed in terms of their relative economics have, thus far, seen actual exploration, development and production activities. These are areas in the Gulf of Mexico and offshore southern California. The economics of exploration and development ventures of these areas are not directly applicable to the 12 other areas because of differences in weather conditions and in distances to major supply centers for oil drilling and for oil producing equipment. Several of these areas, the Gulf of Alaska for instance, will require technology which, thus far, has not yet been used offshore the U.S.A.

We believe that the technology developed over the past six to seven years to find and produce oil and gas fields in the northern part of the North Sea will be applicable to most of the frontier areas which the Bureau of Land Management intends to open up for oil companies through lease sales over the next three years. We have, therefore, analyzed the technical costs which the oil industry have experienced while operating in conditions typical for the North Sea and the Gulf of Mexico, respectively, and these areas have been used as the two benchmark areas against which costs for the other frontier areas on the Outer Continental Shelf were measured.

Generally speaking, environmental conditions as they are encountered in the Gulf of Mexico and offshore southern California can be considered the least severe for the U.S.A. This, combined with the fact that construction sites and supply centers for equipment are all located very close to these areas, renders the Gulf of Mexico and offshore southern California the least costly in terms of unit exploration and unit development activities. Compared to the rest of the United States, the Gulf of Mexico has relatively small field sizes and relatively low well productivities which have resulted in fairly high costs per unit produced or per well drilled, despite the low overall costs.

The exploration and development costs in the other OCS areas will generally be higher than in the Gulf of Mexico and the area offshore southern California. On a comparative basis they will increase going to the north along the Atlantic and Pacific Coast, gradually approaching northern North Sea costs, since the more severe weather conditions which prevail in the northern parts of the Atlantic and the Pacific are similar to North Sea conditions. The general expectation is that the Gulf of Alaska will require even higher exploration and development costs because of earthquake dangers in addition to the severe weather conditions and the short working season.

Seismic conditions, such as earthquakes, are not a problem in the other Alaska offshore areas, but other problems, like the occurrence of icebergs and the question of how to prevent collisions between floating icebergs and fixed structures have, as yet, not been resolved.

The timing of investments and other expenditures for development and production of a field are very important when assessing the overall profitability of a field. Estimates have been made of the average durations for the different areas for finding and developing different sized fields under different circumstances. As for unit exploration and development costs, the duration of development activities will increase northwards from the Gulf of Mexico area and the offshore southern California area with their mild weather conditions and their proximity to supply centers to the north along the Pacific Coast. The duration of development activities in the northern areas will be close to or longer than the lead times experienced in the northern North Sea and, as such, will increase the economic cost per unit produced.

1. Exploration and Appraisal

Exploration comprises all activities which companies undertake before they determine if commercial oil and gas are present in a certain area. In the U.S., these activities can be broken down in two categories:

- Pre-lease sale exploration activities consisting of magnetic*, graphimetric**, and seismic*** surveys, and

- Post-lease sale exploration activities consisting of exploratory and appraisal drilling and more detailed seismic surveys.

Companies buy leases, through a cash bonus bidding system, for the rights to explore for and develop oil and gas on tracts which generally have a size of three square miles or 5,760 acres.

Seismic surveys are by far the most important of the three pre-lease sale type of surveys mentioned in providing companies with the first information about the type and size of structures underlying OCS areas for which BLM has announced a particular lease sale, The cost of these surveys is usually shared among several companies, which, thus, obtain the same basic data about the area -- information which they interpret individually. This information gives the companies some indication about the possible location of oil and/or gas trapped in what are usually called structural traps. Table III-6 shows an index of unit acquisition and interpretation costs for geophysical surveys of the different areas offshore the U.S.A. Costs are listed relative to the benchmark area of the Gulf of Mexico (index 100).

The exploratory drilling is performed either from a platform with legs which are adjustable in height, a *jack-up,* from a floating platform, a *semi-submersible* or from a specially-equipped *drill-ship,* depending on the particular conditions in the areas. Drill-ships and semi-submersibles are generally used in waters deeper than 200-250 feet; jack-ups are reserved for shallower waters.

Construction costs of a jack-up rig in terms of 1975 dollars range between $20-30 million, depending on the particular area in which the rig will operate. When contracted by an oil company, the daily contract costs for the rig alone are between $20,000 and $30,000. Additional costs are incurred for supporting services such as supply boats which can cost $1,200 per day in the Gulf of Mexico to $4,000 per day in Cook Inlet in Alaska. These costs, together with estimates of other costs such as casing and

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*Measures changes in the earth's magnetic field occasioned by discontinuities in the earth's crust.

**Measures changes in the earth's gravity force.

***Measures the reflection of soundwaves.

TABLE III-6

AN INDEX OF MARINE GEOPHYSICAL SURVEY COSTS PER LINE MILE FOR ACQUISITION AND FOR PROCESSING (1975)

<u>Acquisition</u>

Gulf of Mexico	(benchmark area)	100
Atlantic Coast		127
Pacific Coast		127
Gulf of Alaska		132
Chukchi Sea		127
Bering Sea		132
Beaufort Sea*		1136

<u>Processing and Interpretation</u>

New Areas	95
Established Areas**	130

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

**Interpretation of data from established areas requires more of an effort because the large and obvious structures have already been explored.

Source: Arthur D. Little, Inc., estimates based upon published information, mostly from the *Oil & Gas Journal*.

cementing costs, logging survey costs, drilling mud costs, helicopter costs and mobilization and demobilization costs of the rig, are shown in Table III-7.

When drilling in deeper waters, companies will contract a semi-submersible or a drill-ship which is capable of drilling down to 25,000 feet in water depths of over 1,000 feet. A large semi-submersible till cost 40 to 50 million dollars to construct and equip, which implies that an oil company will have to pay $40,000 to $50,000* per day to the drilling contractor. Costs for other supporting and special services and for raw materials, shown in Table III-7 can be another $20,000 to $30,000 for a typical well drilled in the North Sea. Since as many as 120 days can be required to drill an exploratory well (depending upon well depth) the cost of an exploration well in the North Sea can be as high as nine million dollars.

The number of days required to drill an exploration well is not only dependent on the well depth and the particular formations which have to be drilled through, but also on the prevailing weather conditions. This is illustrated by Figure 111.4 where the relation between average sea states and percent downtime per month and cost per foot for wells drilled in the North Sea is shown. It can be seen that the exploration costs for the same type of well in the same area can fluctuate between one and nine million dollars depending upon whether the particular well is drilled during summer or during winter.

The number of exploratory wells which are required to fully explore a given tract of three square miles can range from one, in the case where a very large and simple structure underlies the particular tract, to up to three or four in the case of a more complicated geology as it exists in the Gulf of Mexico, for Instance.

The two factors of wide variation in individual well costs and disparity in the number of wells required to fully explore a tract render it impossible to determine the precise cost for exploration of tracts in those OCS areas where drilling has not yet taken place.

If a discovery is made and oil and/or gas are found in commercial quantities, further drilling is required with the help of the exploration rig to further delineate the field. This field delineation or appraisal drilling can require another three to six wells depending on the complexity of the geology where the field has been found.

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*Source: "Drilling Costs," P. B. Jenkins, A. L. Crockford; paper presented at the Spring meeting, 1975, of the Society of Petroleum Engineers of AIME held in London.

TABLE III-7

COST BREAKDOWN FOR A HYPOTHETICAL 10,000 FT. WELL,
NORTHERN NORTH SEA DRILLED BY A CONTRACTOR RIG
(Mid-1974)

Activity	Cost Units	cost $	% of Total
Preparation	Mobilization/Demob. Site Preparation Transport Rig Move	147,000 25,000 84,000	3.9 0.7 0.9
Drilling Installation Running Costs	Contract Payments Drilling Materials Fuel Salaries Maintenance	2,000,000 11,000 85,000 30,000 23,000	53.1 0.3 2.3 0.8 0.6
Drilling Materials	Mud Bits and Coreheads Casing Cementing	154,000 48,000 245,000 41,000	4.1 1.3 6.5 1.1
Evaluation	Logging Intermediate Testing Misc. Evaluation	135,000 15,000 30,000	3.6 0.4 0.8
Transport	Sea Air	545,000 124,000	14.5 3.3
	Overhead	68,000	1.8
	Total	3,760,000	100

Source: Society of Petroleum Engineers of ALME, paper #SPE 5266, "Drilling Costs," P. B. Jenkins and A. L. Crawford, 1975.

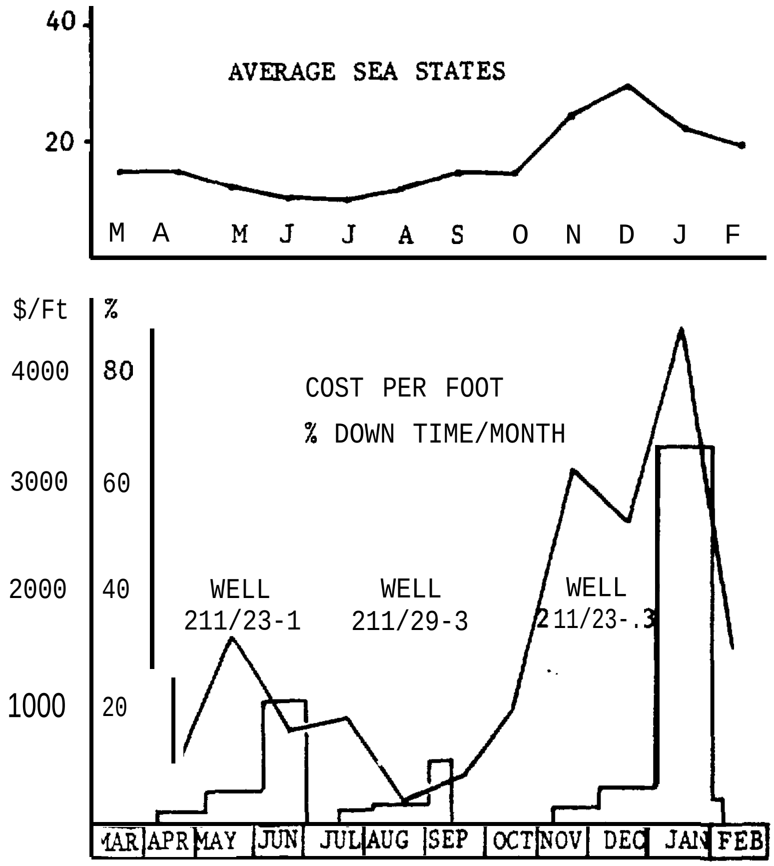

FIGURE III.4 The Relationship Between Sea State
Cost Per Foot and Percentage Down Time
(Based on data from the Sedco 135F)

Source: Society of Petroleum Engineers of ALME, Paper #SPE 5266, "Drilling Costs," P.B. Jenkins and A. L. Crawford, 1975.

Table III-8 shows the range of total exploration and appraisal drilling costs which a company may have to incur in the 17 different OCS areas to fully explore and appraise a tract of 5,760 acres.

2. Development

The development of an offshore oil or gas field requires:

a. The construction and installation of a production platform,

b. The manufacture and installation of production equipment,

c. Drilling of producing wells and wells used for injection of water and/or gas, and

d. The installation of facilities which enable transportation of the oil and/or gas to an onshore terminal.

Oil and gas require treatment after they are produced and before they can be moved by pipeline to onshore terminals. A combination of environmental and economic considerations necessitates that the treatment be done on-site. This treatment consists mainly of separation of water and hydrocarbons since "formation" water is usually produced along with the oil or gas.

All of the equipment required for treatment of the produced fluids, together with other types of equipment such as cranes, living quarters, a power plant, compressors, a helicopter landing deck, etc., is located on an artificial insland or platform which is standing on the sea bottom or is floating right above the particular oil or gas field.

The weight of the entire equipment and facilities' package may total up to two-tenths of a ton for every barrel of oil produced per day at peak capacity. For gas production platforms, the total weight is approximately one-tenth of a ton for every ten thousand cubit foot per day of peak capacity.

Currently, the majority of production wells aredrilled from fixed platforms. The platform provides a stable basis from which these wells can be drilled and completed using deviation drilling techniques from which areas in the reservoir, generally at depths between 5,000 and 15,000 feet, can be reached as far out as one to three miles measured from the vertical down from the platform.

The costs of fixed platforms increase exponentially with increasing water depth and with increasing severity in weather conditions. Therefore, a strong economic incentive exists to look for alternative ways to develop the oil and gas fields which lay under deep waters or which have severe weather conditions. In the following section, the technological costs of the more conventional type of field development using wells drilled

TABLE III-8

RANGE OF TOTAL
EXPLORATORY AND APPRAISAL DRILLING COSTS
PER TRACT OF 5760 ACRES
(1975 $)

AREAs	Variable costs(1) ($1000/Day)	Fixed costs(2) $MM/Well	Number of Days Days/Well	Cost Per Well $MM/Well	Wells Per Tract	Cost Per Tract $MM
Atlantic Coast (1,2,3)	25-35	.6- .7	20-100	1.1-4.2	1-6	1.1-25.2
Gulf of Mexico (4,5,6)	25-35	.5- .6	20-100	1.0-4.1	1-6	1.0-24.6
California (7,8,9)	25-35	.5- .6	20-100	1.0-4.1	1-6	1.0-24.6
Oregon & Washington (lo)	25-35	.6- .7	20-100	1.1-4.2	1-6	1.1-25.2
Alaska, South (11,12,13)	50-75	.8- .9	30-120	2.3-9.9	1-6	2.3-59.4
Alaska, East (14,15)	40-55	1. -1.2	30-120	2.2-7.7	1-6	2.2-46.2
Alaska, North-east (16)	40-55	1.1-1.3	30-120	2,3-7.9	1-6	2,3-47.4
Alaska, North (17)	40-55	1.2-1.4	30-120	2.4-8.0	1-6	2.4-48.0

Source: Arthur D. Little, Inc., estimates.

and completed from fixed platforms are compared with the costs of a newer alternative using subsea completion technology and floating platforms. This *latter type* of development has by now reached the prototype stage ant! is being used in the development of several North Sea oil fields. The success of this technology will set the rate at which subsea completion technology can be expected to be used in offshore oil and gas development in the frontier areas of the U.S. Technology for transporting oil and gas from the field to onshore receiving terminals has also undergone significant changes and increasing water depth, more severe weather conditions and longer distances to shore have resulted in increases in costs for bringing the oil and gas onshore.

For gas, cost reduction for transporting the gas onshore is limited to improvements in pipelaying and burying techniques. Liquefaction at the OCS field site enables transportation of the gas by tankers but may be too costly relative to present day prices of 50-60¢ per MCF.* Even floating offshore LNG plants will probably not be able to produce gas for distribution at current U.S market prices. Also, the floating LNG plants currently under construction are intended for the relatively calm environment of the Arabian Gulf and the Java Sea, where LNG tankers can me.. alongside.

For oil, tanker transportation to shore has been shown to be an attractive alternative compared to pipeline. The costs for these two alternatives are presented below *as* a function of the maximum capacity of the transportation system and the distance to shore.

a. Platform

Figure 111.5 shows the various alternative platform constructions which industry is presently using or testing offshore.

The *conventional steel jacket* is the original type of platform of the industry. In the Gulf of Mexico, steel jackets have been used for over 20 years in water depths of up to 350 feet while in the North Sea, steel platforms in water depths of up to 450 feet have been installed.

Concrete platforms were introduced in the North Sea to minimize costs and delivery times. Concrete platforms, however, now cost at least as much as steel platforms for the same water depth and weather conditions, but they can include oil storage capacity of up to a million barrels for a small additional cost (about 5%). In addition, they can accommodate production equipment for capacities of over 200,000 barrels per day, which is beyond the upper limit for steel platform designs for the North Sea. They do, however, require a deep water inlet for construction.

It is expected that the size of concrete platforms (150,000 to 300,000 tons and requiring 70,000 to 80,000 HP for towing} renders it difficult to tow them over the Atlantic Ocean for use off the East Coast of the Us. Deep water inlets suitable for construction are not easily available.

*When this report was being written wellhead prices of gas were still at a maximum of 52¢/MCF. Since, the FPC per $ released that wellhead prices for new gas may go up to $1.42/MCF. The final approval of these new higher wellhead prices is subject to court discussions in suits brought by groups which oppose the price hike.

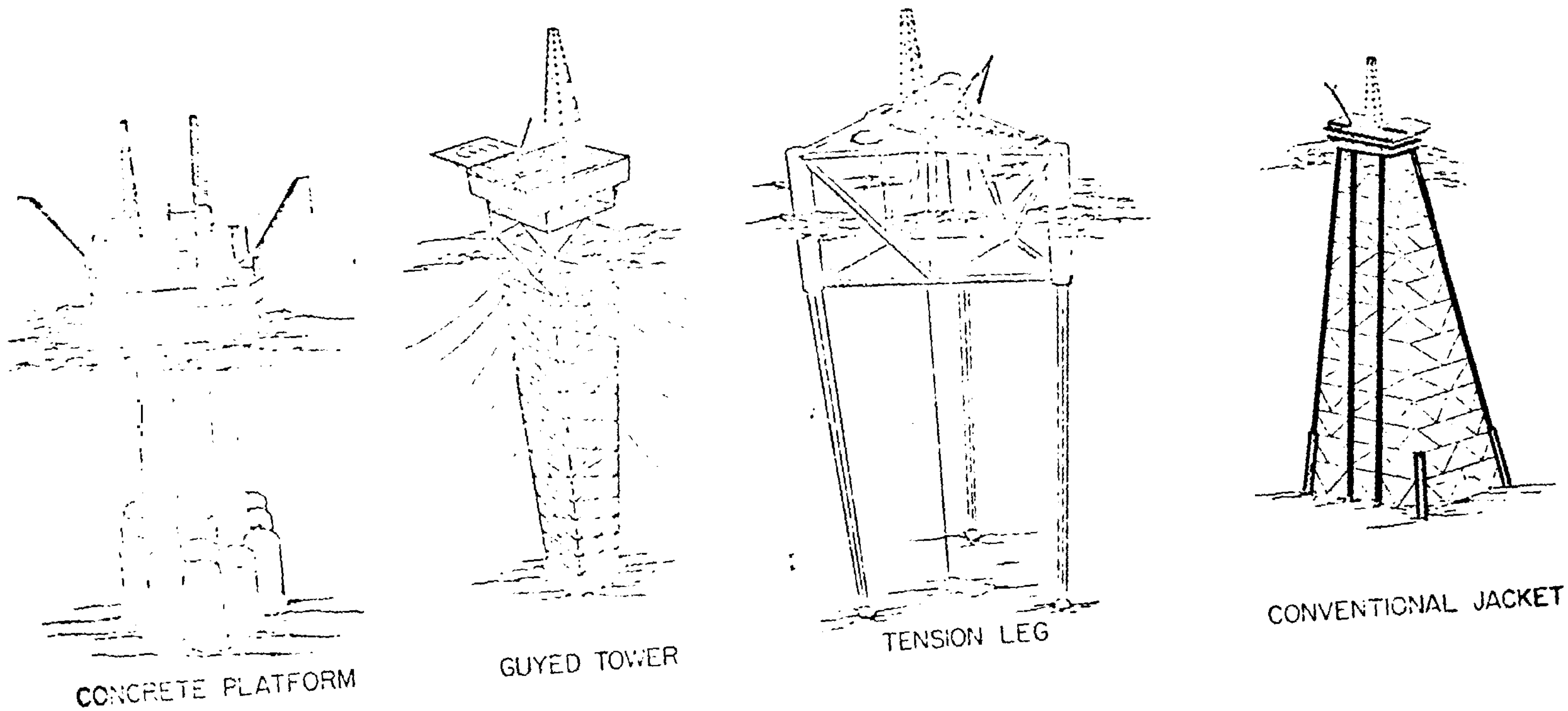

FIGURE III.5 Alternative Fixed Platform Constructions for Offshore Production of Oil and Gas

Source: Oil & Gas Journal.

The Canadian East Coast (e.g., the Bay of Fundy) offers several potential construction sites for these platforms, although large tidal variations may prove to be a problem.

The only potential construction site for concrete platforms on the West Coast of the U.S. is the Puget Sound at Seattle. It will, therefore, be more likely that concrete platforms will be used in the development of areas off the West Coast and off the Coast of Alaska.

In addition to the all-steel and all-concrete platform designs, there are other designs which combine concrete and steel each with its claim on cost advantages over the all-concrete and all-steel designs. However, as yet, none of these designs has been tested under field conditions which precludes any forecast about their cost. It can be expected, though, that some of these designs will eventually be used in the development of offshore fields.

The *guyed tower* concept is now undergoing a small scale test in the Gulf of Mexico to test this platform type for development of fields in the very deep waters in the Santa Barbara area off the coast of southern California. This tower design saves on steel requirements for the Tower by dissipating part of the wave and wind energy exerted on the platform through the guidelines rather than through the structure Itself, as in the case of a conventional steel platform. The current experimental stage of this platform concept precludes an assessment of what its cost will be. Exxon reportedly intends to use this type of tower in water depths of 1500 feet.

The *floating platform* used in combination with *subsea completions* is another alternative which is used in the development of certain smaller fields in the North Sea. The obvious advantage is that the cost of fabrication and installation of the platform is much less dependent on the particular water depth in which it is being used. The sensitivity of a floating platform to wave movements requires that the wells be completed on the sea bottom rather than on the platform itself. The production from individual wells can then be combined by a subsea manifold and delivered into the treatment facilities on top of the platform through one single pipeline or riser which, under severe weather conditions, can be disconnected between the floating platform and the sea bottom. In spite of the limited experience with this type of development system for an oil field, enough cost information is available to make a tentative comparison with the other more conventional fixed platform systems.

Platform Capacity and Well Productivity

The deck load of a platform is a function of the maximum design capacity of the platform production equipment. There can be large variations in type and size of equipment used to treat a given amount of produced fluids, depending on whether these fluids are dry gas or gas with condensate, heavy crude oil with only a trace of associated gas or light crude with a relatively high gas/oil ratio. In addition, it is possible that the particular type of reservoir will require pressure maintenance through water injection and/or gas reinfection, which then will result in additional equipment requirements.

The maximum capacity which existing platforms can accommodate is constrained on the low end, by the maximum number of production wells (normally assumed to be 40) and on the high end side it is constrained by the maximum platform size which can be constructed. The largest steel platforms that have been constructed for the North Sea are capable of accommodating production equipment for up to 150,000 bbls per day of crude oil and up to 200 million standard cubic feet per day of gas in addition to water injection equipment for up to 300,000 bbls per day. Concrete platforms now under construction for the Statfjord field will be able to handle up to 300,000 bbls per day of crude oil and to treat and reinject up to one-half million cubic feet of gas per day in addition to reinfection of up to 400,000 bbls per day of water.

The number of wells that can be drilled from a given platform will depend upon:

- the reservoir characteristics of the particular oil or gas reservoir such as the porosity, connate water* saturation, permeability, and type of drive mechanism;
- the height of the produced oil or gas column in the reservoir; and
- the average depth of the reservoir.

As shown in Table III-8, the maximum area which can be produced from one fixed platform is dependent on the depth of the reservoir. Under the assumption that a deviated well can be drilled to an angle of up to 50" with the vertical, the maximum number of acres to be produced from a single platform for an oil field, typically found at a depth of between 5,000 and 10,000 feet, can range from 2,000 to 8,000 acres; for a gas field, which will typically be found between 10,000 and 15,000 feet, this can range from 8,000 to 18,000 acres.

The number of wells which have to be drilled to produce the oil and/or gas contained in the area shown in Table III-9 will depend upon the well spacing, that is, upon the number of acres of reservoir which can be produced by one well. As mentioned earlier, this well spacing is mainly

*The porous spaces in most reservoir rocks were originally filled with water which was then replaced by oil and/or gas, leaving only a film of water on the rock surface: the connate water.

TABLE III-9

MAXIMUM SIZE OF AREA WHICH CAN BE PRODUCED WITH DEVIATED WELLS DRILLED FROM A SINGLE PLATFORM[1]

Depth of Reservoir[2] (in ft.)	Maximum Size of Area Which Can be Produced With a Single Platform in Acres[3]
5,000	2,000
7,500	4,500
10,000	8,000
12,500	12,500
15,000	18,000

[1]Assuming a maximum angle of deviation with the vertical of 50°.

[2]The range of 5000-10,000 ft. is representative for oil reservoirs, while the range of 10,000 - 15,000 ft. is more typical for gas reservoirs.

[3]The maximum size of a tract offshore U.S.A. is 5760 acres or three square miles.

Source: Arthur D. Little, Inc., estimates.

a function of the type of reservoir fluid produced, oil or gas, and of the reservoir characteristics such as the connate water saturation, porosity, permeability, and the driving mechanism. It is beyond the scope of our analysis to show how well spacing can vary as a function of each of these parameters. Therefore, we have used well productivity and recoverable reserves per acre as two composite parameters with which well spacing will vary.

Using what can be considered to be a typical production profile for an oil well with a producing plateau, at peak capacity, of about five years, followed by a period of decline of 15 years at 15% per annum, it was calculated what the well spacing would have to be at different values of recoverable reserves ranging from 10,000 to 200,000 stock tank barrels per acre. The results are shown in Figure 111.6 where the range of values found in the Gulf of Mexico and the North Sea for well productivities and recoverable reserves are indicated by shaded areas.

In a similar fashion, recoverable reserves have been estimated for gas reservoirs ranging from 50,000 to 400,000 million standard cubic feet per acre and well productivities ranging from 10 to 80 million standard cubic feet per day. For gas, a typical production profile was considered with a peak production plateau of ten years followed by a 30-year period of declining production, declining at an annual rate of 10%. Figure 111.7 shows the results with indications of typical values for gas well spacings in the Gulf of Mexico and in the North Sea.

It should be noted from Figures III.6 and 111.7 that gas fields, in general, admit larger well spacings than oil fields. Gas fields have well spacings between 500 and 8,000 acres per well, oil fields have more typical well spacings of 80 to 2,000 acres per well.

Combining the information on range of well productivities, recoverable reserves per acre and area of reservoir to be produced at different depths from one single platform, one can estimate the range of platform sizes that will be required in the unexplored OCS areas. In Figure 111.8, it is shown that full use of economies of scale for fixed platforms by use of the maximum sized platforms which can currently be constructed is only possible under exceptionally fortunate circumstances where the oil reservoir is found at a depth of approximately 10,000 feet and with reservoir characteristics allowing very high well productivities of around 10,000 barrels per day from a thick reservoir with recoverable reserves of around 150,000 barrels per acre and total recoverable reserves of 500 million barrels.

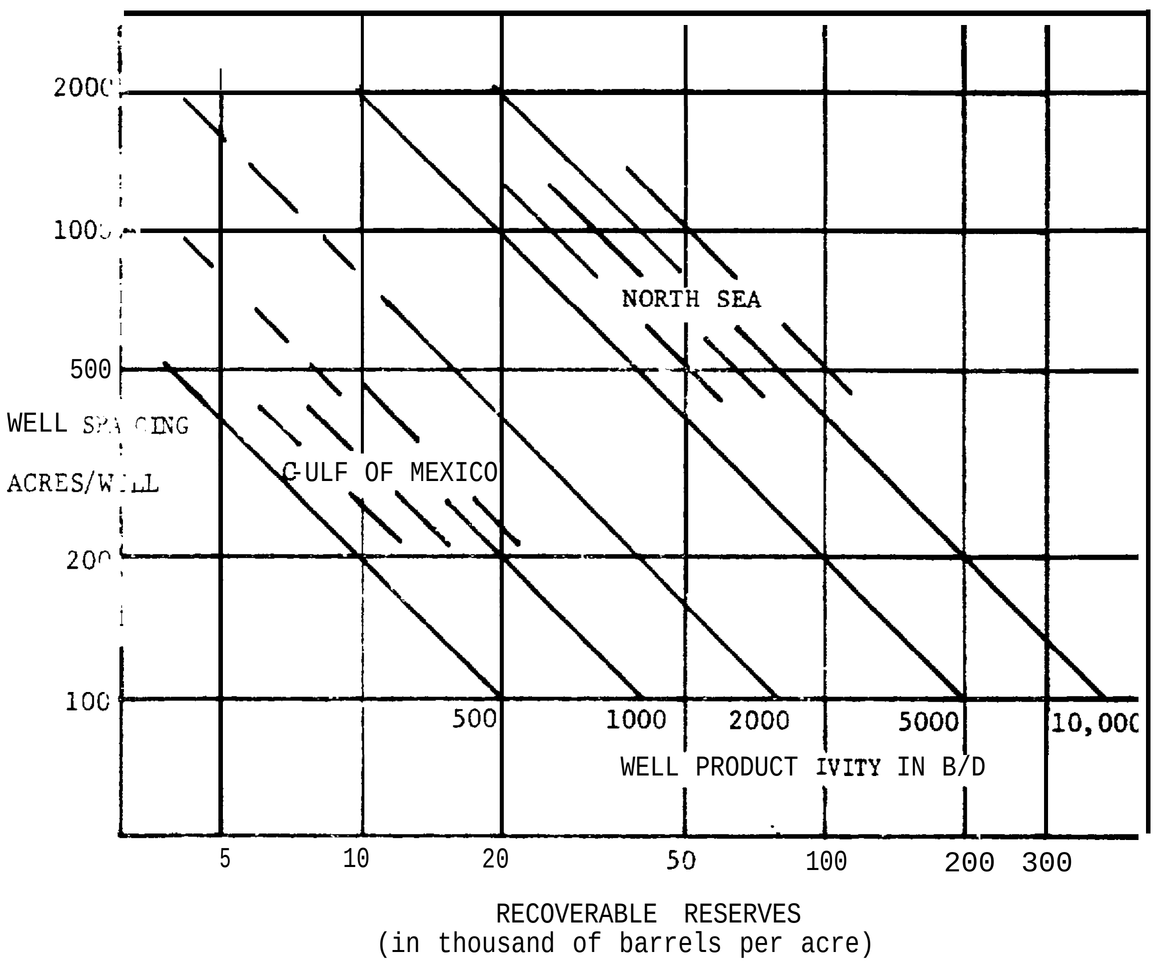

FIGURE III.6 Well Spacing as a Function of Recoverable Reserves Per Acre (Oil)
(Assuming a 5-year plateau followed by 15 years of decline at a rate of 15% per annum.)

Source: Arthur D. Little, Inc., estimates.

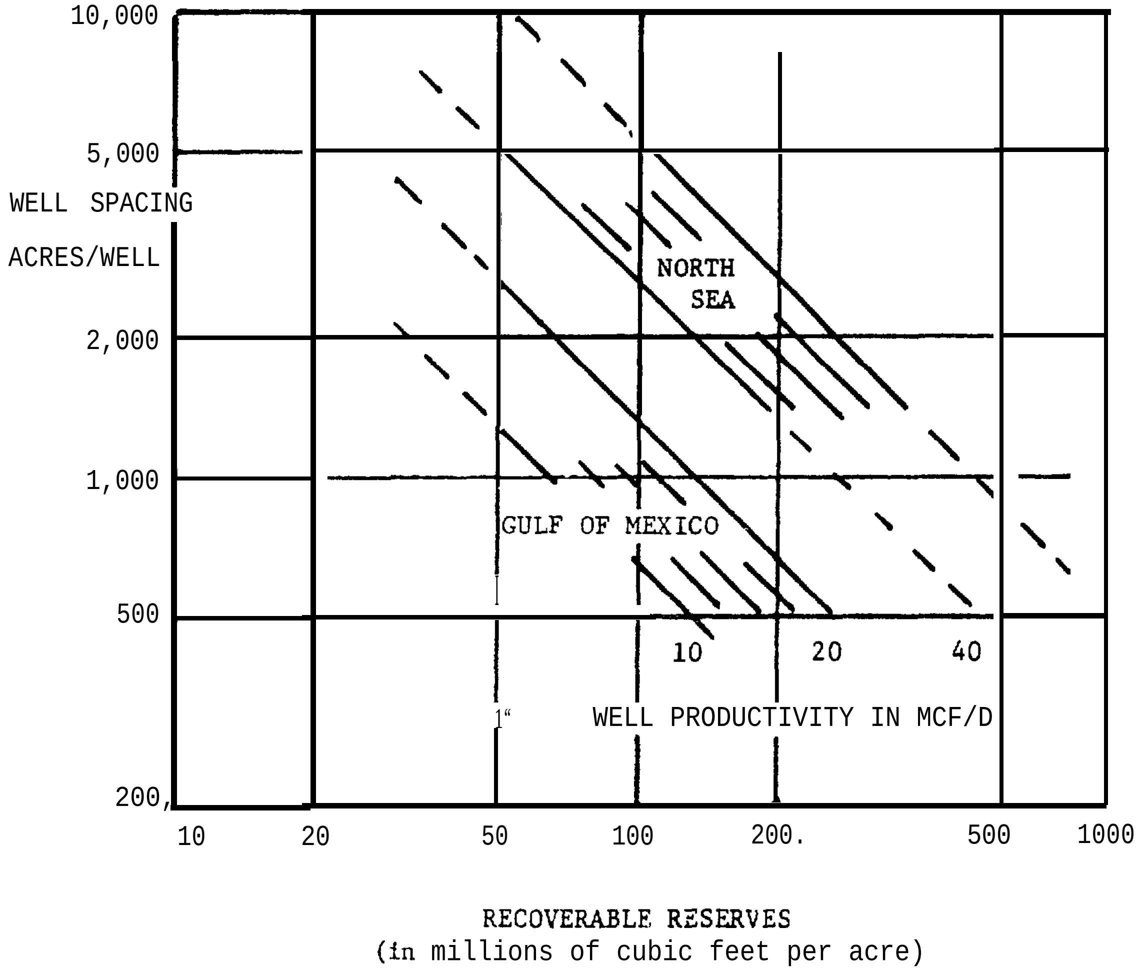

FIGURE III.7 Well Spacing as a Function of Recoverable Reserves Per Acre (Gas)
(Assuming a 10-year plateau followed by 20 years of annual decline at a rate of 10% per annum.)

Source: Arthur D. Little, Inc., estimates.

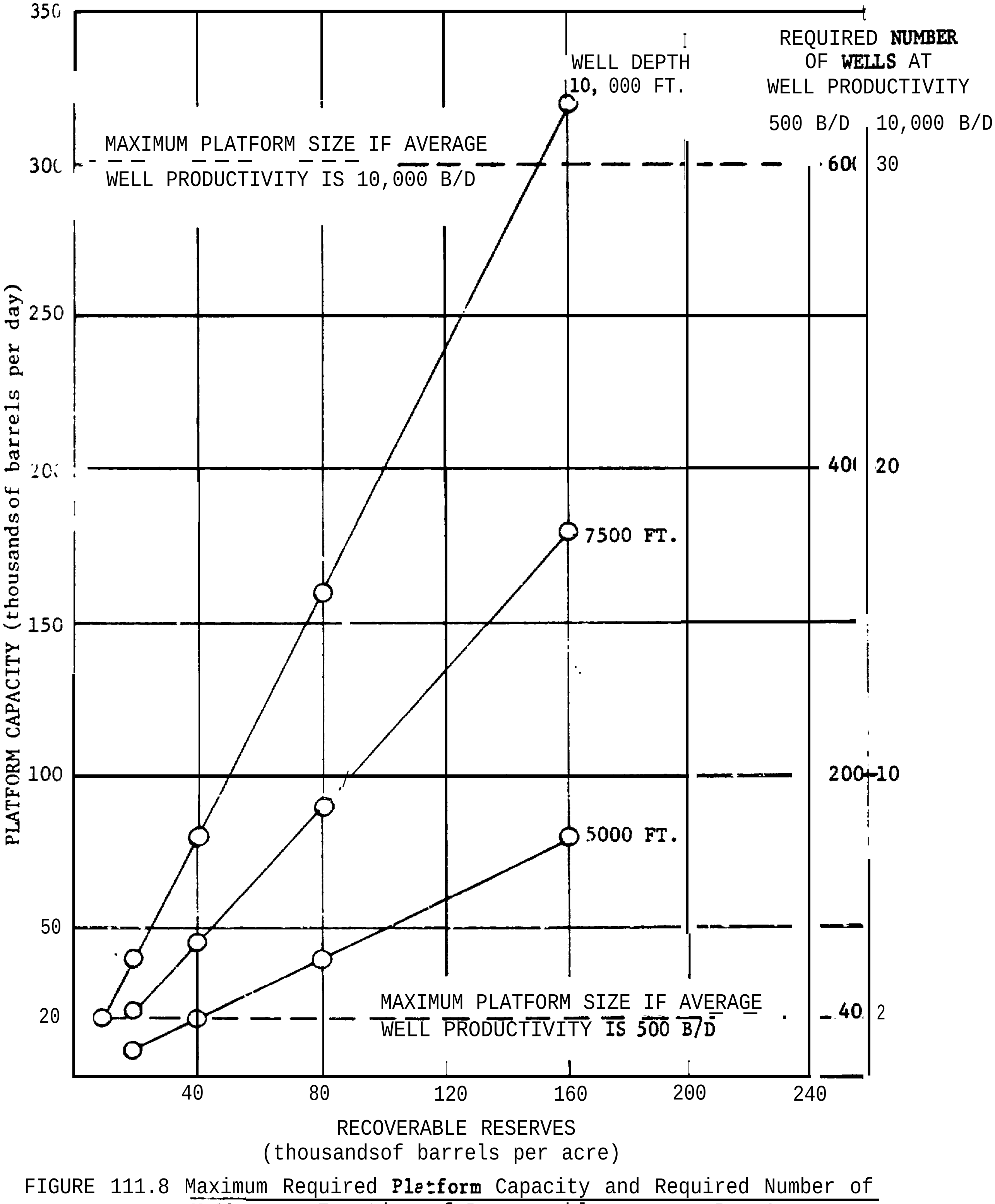

FIGURE 111.8 Maximum Required Platform Capacity and Required Number of Wells as a Function of Recoverable Reserves Per Acre for Different Well Depths

Source: Arthur D. Little, Inc., estimates.

Platform Fabrication Costs

The much more *severe* weather conditions in the North Sea exemplified by a design wave ranging from 90 to 100 feet, compared to the Gulf of Mexico, where the design waves are more in the range of 60 to 70 feet, requires much heavier structures for the same water depths. This can be seen in Figure III.9 where it is shown that, for instance, in water depths of between 200 and 400 feet, steel jackets in the Gulf of Mexico require 10 to 13 tons of steel per foot of water depth compared with steel jackets in the North Sea requiring 20 to 38 tons of steel per foot of water depth.

For comparison purposes, weight estimates for a steel jacket strong enough to withstand weather conditions and earthquakes in the Gulf of Alaska as shown in the same figure.

Figure III.10 shows actual and estimated construction costs of steel and concrete sub-structures in various offshore areas, relative to the cost of those structures in the benchmark area of the Gulf of Mexico.

In interpreting Figure 111.10, it should be realized that the deck loads which are. typically required for the Gulf of Mexico as a rule do not exceed 20,000 barrels of oil a day, or 200 million cubic feet of gas, while oil production capacities for platforms in the North Sea typically range between 100 to 200 thousand barrels per day, or five to ten times as large.

For comparison purposes, we have also included in Figure III.10 *the* range of costs for the fabrication of sub-structures of jack-ups and semi-submersibles. Semi-submersibles are used in the North Sea in the development of two small fields, in conjunction with subsea completions. In these cases, it has been found to be more economically attractive to develop the relatively small fields of 50 to 100 million barrels of recoverable oil with four or five wells drilled from a semi-submersible and completed on the sea bottom, and to produce those wells into separation and treatment equipment located on top of a converted semi-submersible*.

*Source: Jerome C. Gordy, Windsor A. Thomas, *Hamiltons' Argyll Semi-submersible/Production Riser* Concept, paper presented in the Spring meeting 1975 of the Society of Petroleum Engineers of AIME.

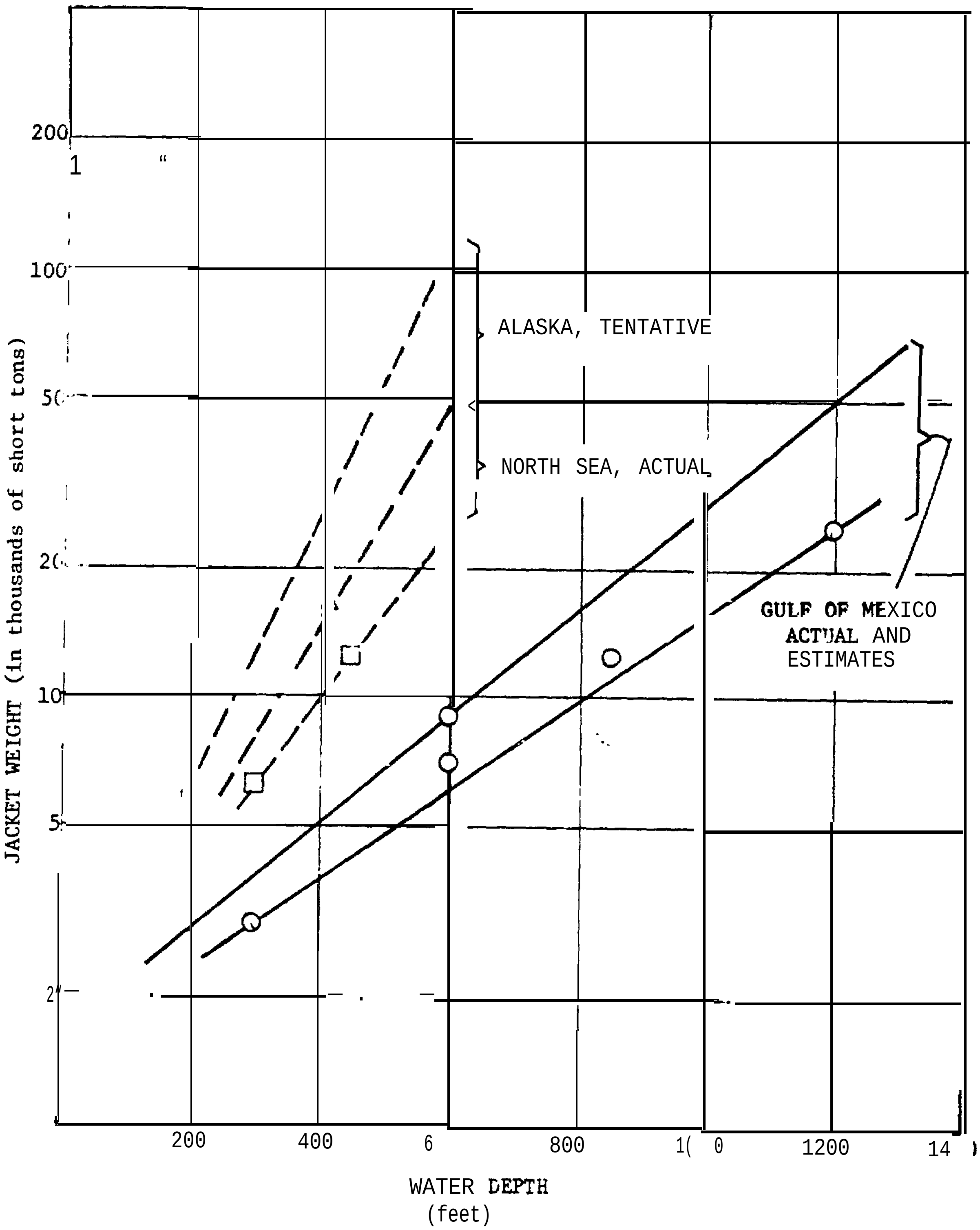

FIGURE III.9 Steel Jacket Weights Versus Water Depth

Source: **Arthur** D. Little, Inc., estimates.

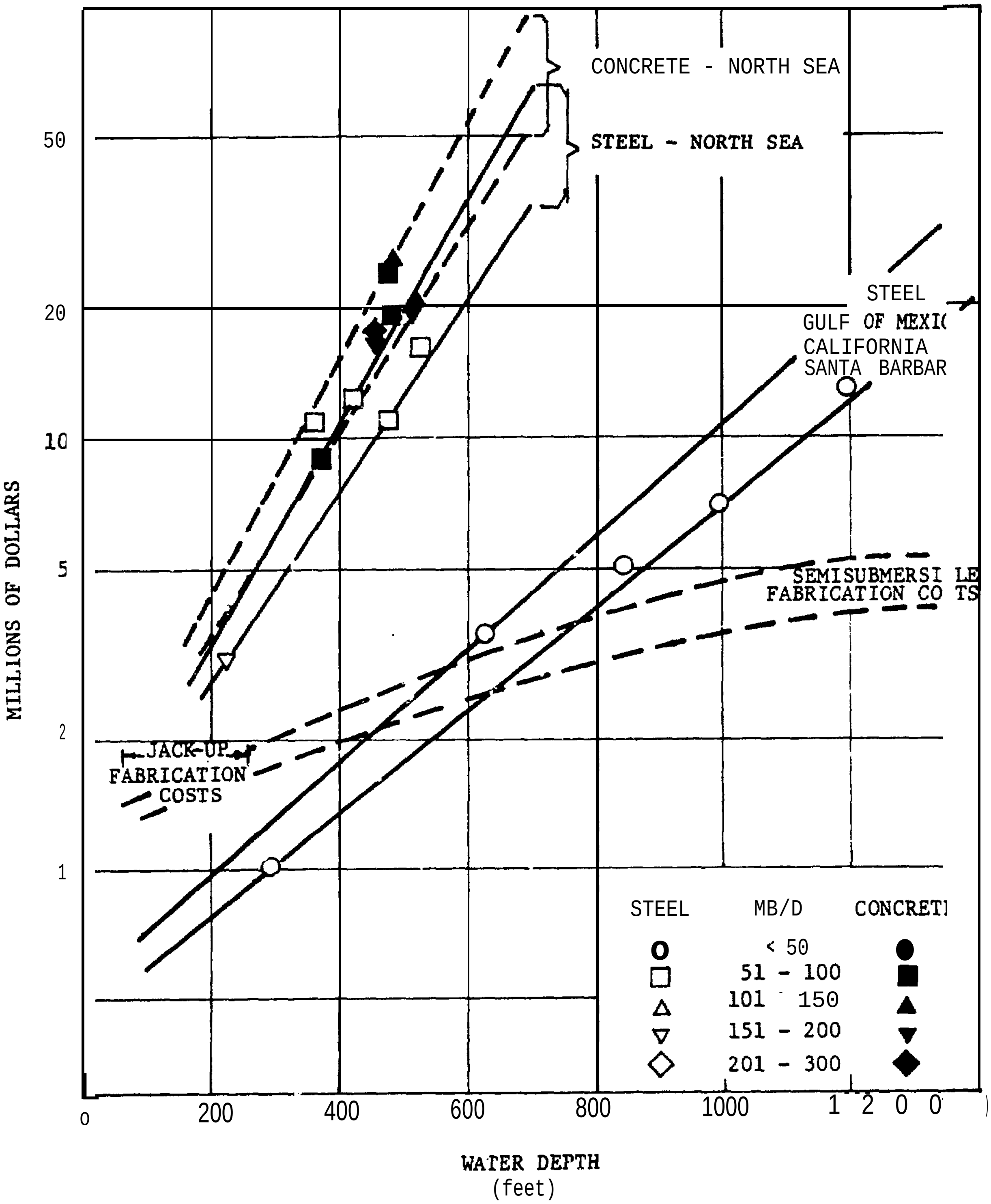

FIGURE 111.10 Platform Fabrication Costs (1975 $)

Source: Arthur D. Little, Inc., estimates.

There is strong indication that in high cost areas such as the North Sea, larger fields initially may be developed in this manner as well. In this case, subsea completion would be an intermediate solution to obtain more information about the actual reservoir characteristics and to obtain positive cash flow while waiting for the construction of the large fixed platform which usually takes two to three years.

Cost data available for substructures which have been constructed or are under construction for use in the North Sea indicate that the weather load factor is dominant in the overall design. An analysis of platform construction costs as a function of capacity show that these fabrication costs are relatively insensitive to capacity over the range from 50,000 to '10,000 barrels per day. However, it must be realized that most designs for which cost estimates are shown in Figure 111.11 are still in the prototype stage and that they most probably will undergo significant co " reducing improvements. This can be exemplified by the three platforms which were constructed for the Forties field, where as a result of design optimization, more than 25% steel was saved for the construction of the third platform in spite of the fact that the platform was designed for 450 feet while the first platform had been designed for 415 feet water de (See Figure 111.12). Whether platform costs in the future will be re ed by such engineering optimizations as compared to costs in 1975 will depend on how cost of labor and cost of materials will change on the supply and demand for platforms in general over the next few years.

Based on the analysis of platform construction costs for areas presently under development, supplemented with the results of discussions with industrial sources, the range of construction costs for different sized platforms for the various areas on the OCS have been estimated. For this purpose, the 17 areas were classified into four regions as follows:

- The Gulf of Mexico and the Pacific Coast: OCS areas 4, 5, 6, 7, 8, 9 and 10*;
- The Atlantic Coast: OCS areas 1, 2, and 3;
- The eastern Alaskan Coast: OCS areas 14, 15 and 16 and the southern Alaskan Coast: OCS areas 11, 12 and 13; and
- The Beaufort Sea: OCS area 17.

As shown in Figure 111.13, weather conditions are quite different in the Gulf of Mexico as compared with the Pacific Coast. Maximum recurring wave height and wind speed in the Gulf of Mexico are considerably higher than anywhere along the U.S. part of the Pacific Coast. In spite of this difference in weather conditions, platform construction costs for offshore southern California are comparable with those for the Gulf of

*BLM OCS area classification.

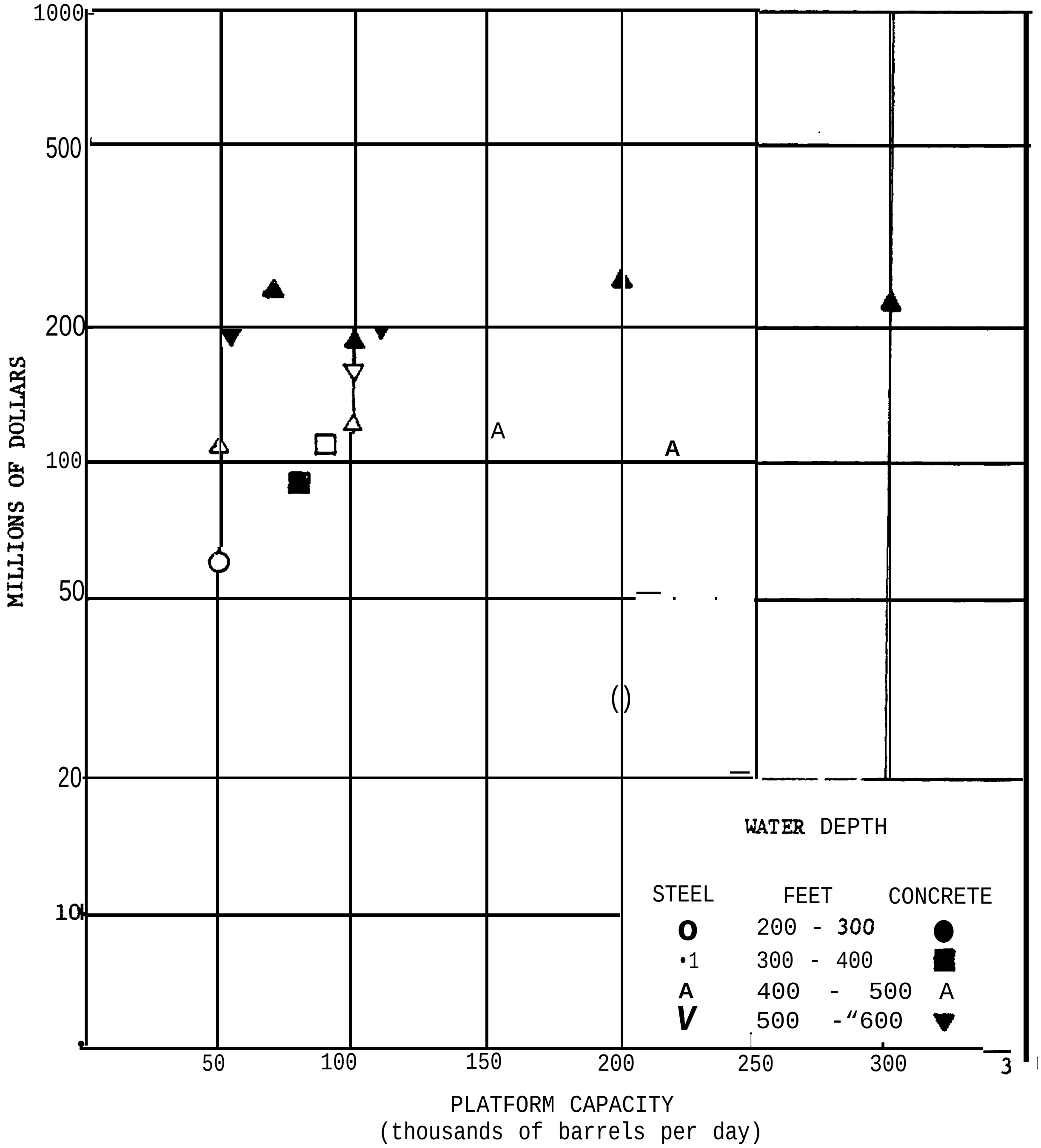

FIGURE 111.11 Platform Fabrication Cost as a Function of Capacity

Source: Arthur D. Little, Inc., estimates.

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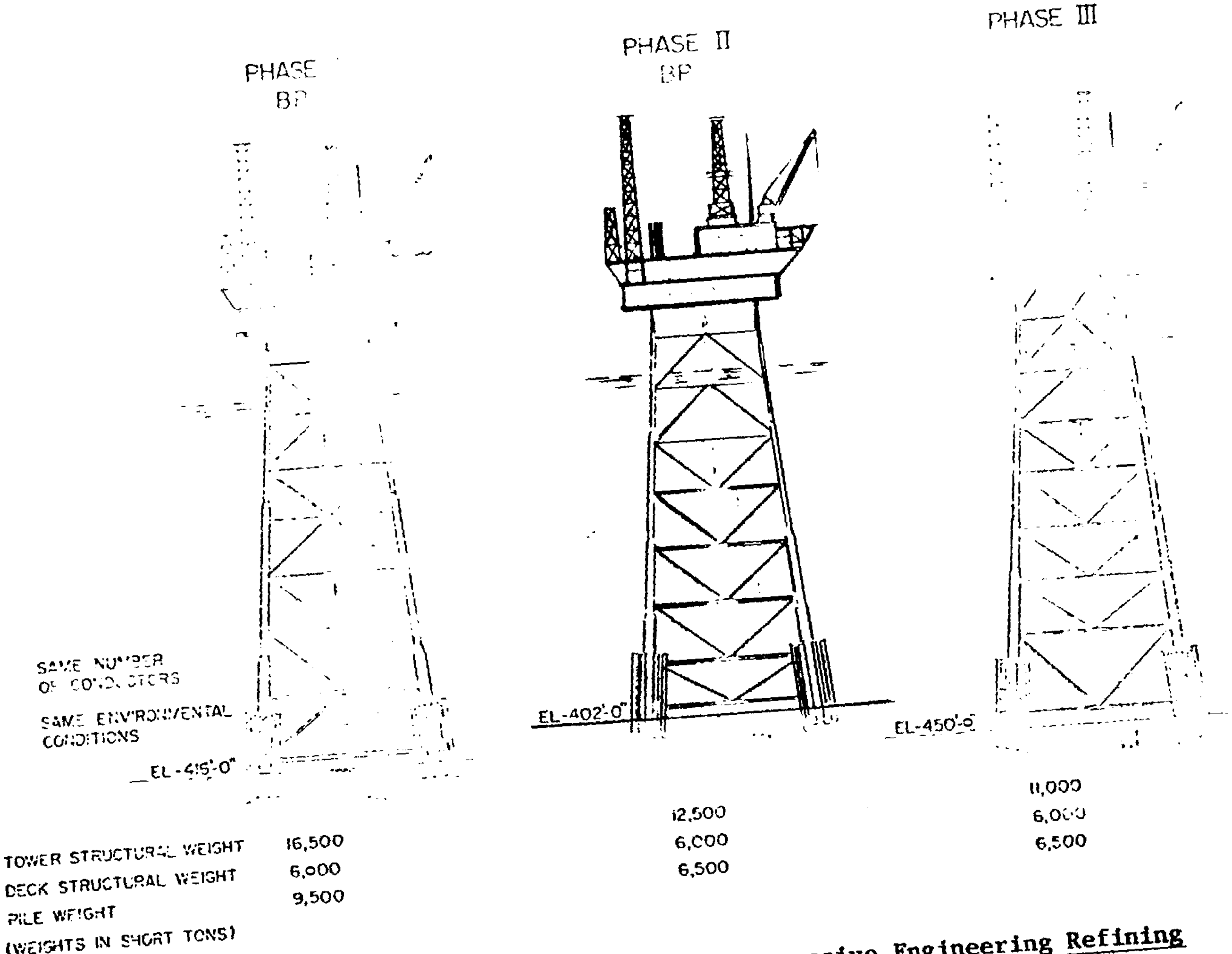

FIGURE III.12 <u>**Effects of Progressive Engineering Refining**</u>

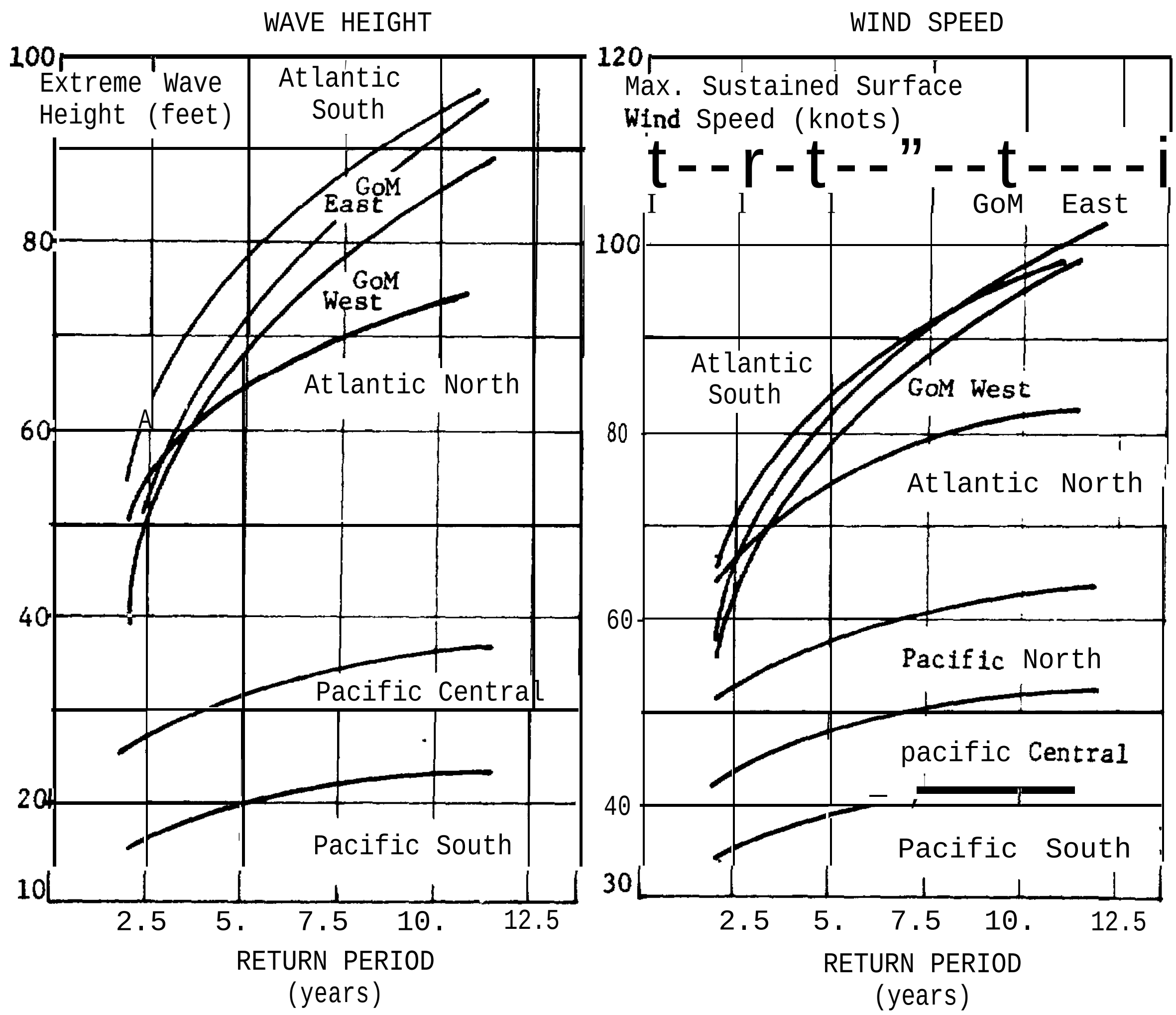

FIGURE IV.13 Recurring Maximum Wave Heights and Wind Speeds of the East Coast and of the West Coast

Source: U.S. Dept. of Commerce

Me%:.co since platforms constructed for use in the waters offshore so.thern California must be able to withstand earthquakes. This results in the use of platform structures quite comparable to the structure.s used in the Gulf of Mexico with its more severe weather conditions.

Figure 111.14 shows how estimated platform construction costs change as a 'unction of water depth In the different areas. Figure 111.15 shows hc. platform costs are expected to change as a function of the required tr :tment capacity for oil and gas. Eased on an inspection of the data fc gas platforms, it was concluded that the same platform size will be required for 10 MCF of gas per day as is needed for one barrel of oil per day.

The expectation is that platform structures to be used offshore northern Ca!:fornia and offshore Washington or Oregon will be comparable to the structures used in southern California. Earthquake danger offshore Wa: ington and Oregon is considerably less than it is in southern Ca l: fornia, but weather conditions are more severe, especially during th- winter season, and it can be expected that platforms will have to ac -mmodate larger stocks of drilling material to enable continuation of tl development drilling during periods of bad weather.

The same argument, that a high chance for long periods of bad weather interfering with the supply of drilling materials will require design for heavier loads, applies also to the Atlantic Coast areas. Hence, since weather conditions in these areas are more severe as those in the Gulf of Mexico it can be expected that platform structures for these areas will be more expensive than comparable structures used in the Gulf of Mexico (see Figure 111.13).

Platform construction costs for the eastern Alaskan Coast are expected to be comparable with platform costs for the northern North Sea. The moving ice during the winter and springtime will require strong and heavy structures, and the extreme cold will require the use of special high grade steel. It has to be remembered, though, that it is not altogether certain that platforms will be used in these areas because of the danger of collision with icebergs.

The most expensive platform structures will be needed for the southern Alaskan Coast where platform structures should be able to survive earthquakes frequently occurring in the area, and weather conditions which are quoted to be even more severe than those in the northern North Sea area. If platform structures will be used for field development in the Beaufort Sea, then they can be expected to cost at least as much as structures used in the Gulf of Alaska.

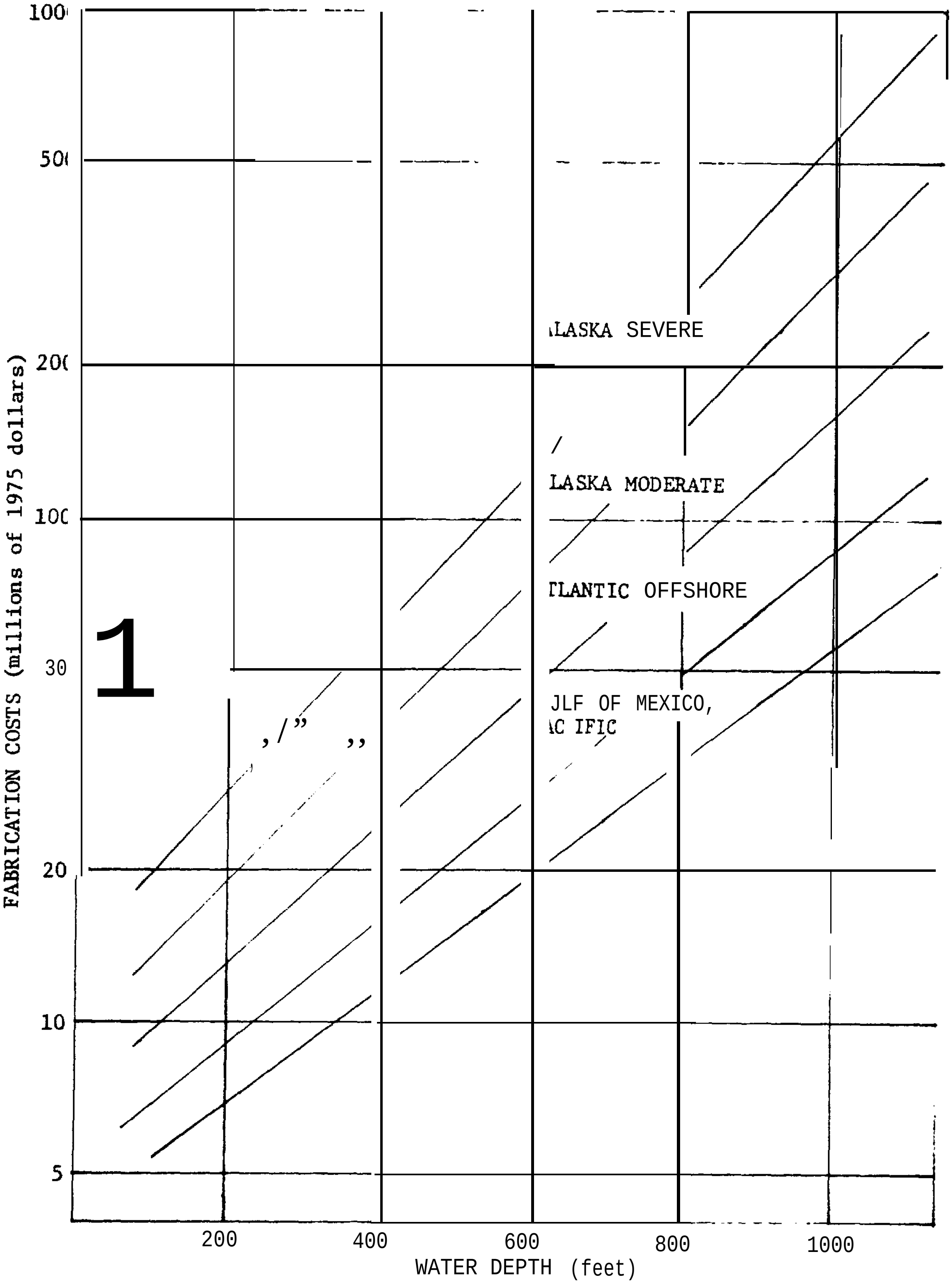

FIGURE III.14 Platform Fabrication Costs as a Function of Water Depth for Different Areas; Capacity 20 MB/D 200 MMCF/D (in 1975 $)

Source: Arthur D. Little, Inc., estimates.

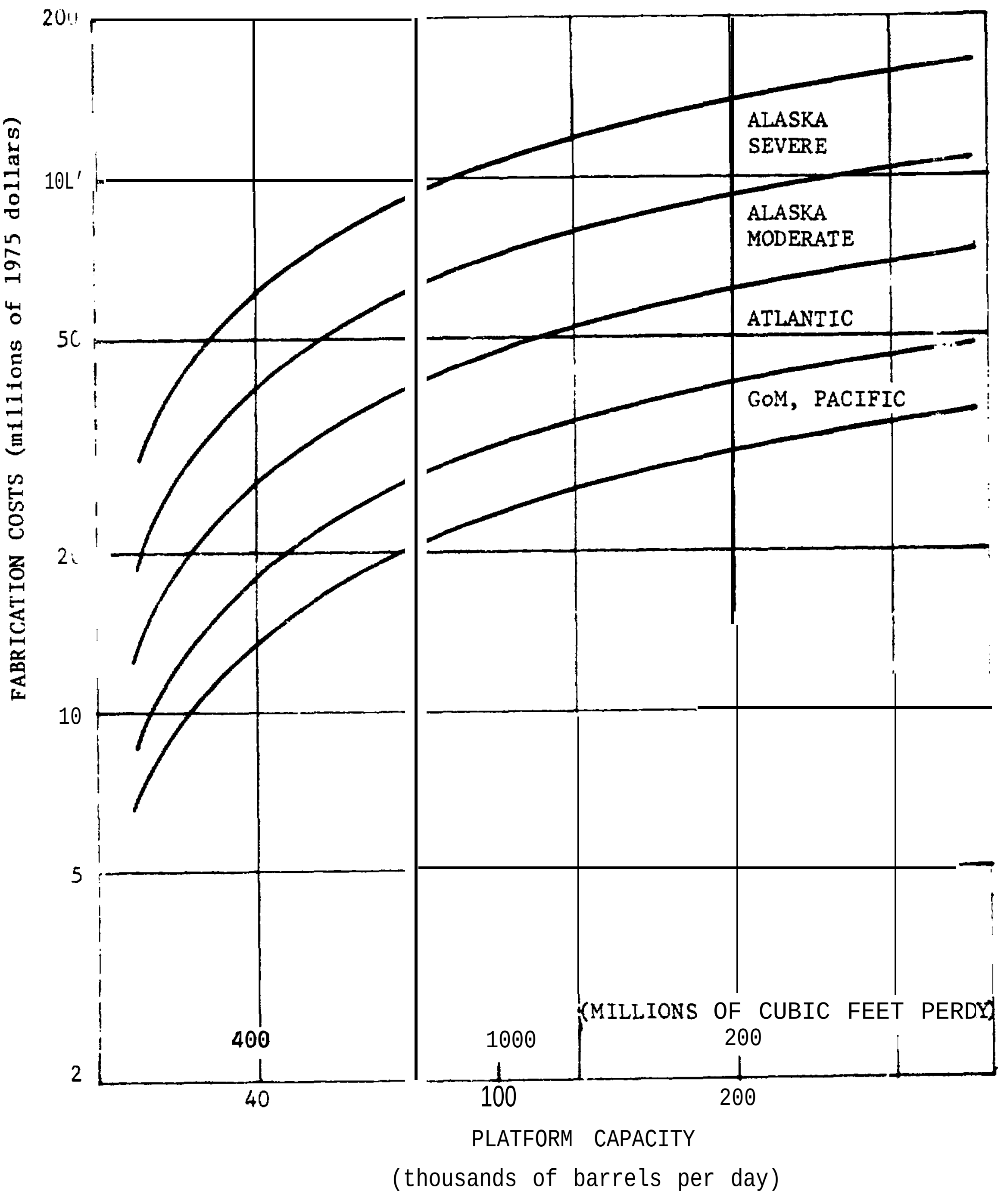

FIGURE 111.15 Platform Fabrication Costs as a Function of Capacity for Different Areas; 300 Feet of Water (in 1975 $)

Source: Arthur D. Little, Inc., estimates.

Platform Equipment Costs

The equipment on a production platform can consist of:

- Oil treatment equipment, such as separators, to remove the formation water and the gas produced with the oil; oil metering and oil storage facilities and pumps to move the oil to shore through the pipeline or to a single-point mooring buoy for transportation by tanker;

- If substantial volumes of non-associated gas are produced, a natural gas liquid plant to remove the condensate and gas dehydrators to remove the water from the gas;

- A water treatment plant to bring the concentration of hydrocarbons in the produced formation water down to a prespecified level and, in the case of a large platform, a sewage treatment plant, both of which are required to comply with pollution control standards;

- A power plant and, in the case of gas production which is not flared, gas compressors;

- In the case of water injection for pressure maintenance purposes, salt water" treatment facilities and injection pumps;

- Living quarters for personnel;

- A helicopter deck;

- Hoisting and lifting equipment;

- Fire-fighting and safety equipment; and

- Drilling equipment.

Some platforms also have a flare stack to burn gas which is not being reinfected or moved by pipeline. In cases where the volumes of gas to be flared are large, such a flare stack will be positioned at a safe distance from the platform on a platform on a separate small structure. This structure can be either a light jacket standing on the sea floor or a floating tower attached to the sea bottom by an articulated joint. In the Gulf of Mexico it is quite common to find the production facilities on a separate platform next to the platform from which the wells have been drilled and completed.

Table III-10 shows the cost breakdown for a large platform in the North Sea accommodating 32 wells, 12 of which are used for gas reinfection and water injection. The construction equipment has been sized to handle, up to 125,000 barrels per day of crude oil, 200 million standard cubic feet of gas per day and 200,000 barrels of sea water per day, respectively.

TABLE III-10

TYPICAL NORTH SEA PLATFORM EQUIPMENT COSTS
(Capacity 125 MB/D Oil 200 MMSCF/D Gas)

	% Breakdown of Total Costs
Oil Production Equipment	25
Natural Gas Liquid Plant	20
Water Injection Plant	5
Power & Switch Gear	20
Living Quarters & Helideck	10
Hoisting & Lifting Equipment	5
Fire Fighting & Safety	5
Drilling Equipment	5
Miscellaneous	5
TOTAL	100%

[1] Mainly Radio Tower and Gas Flare. .

Source: Arthur D. Little, Inc. , estimates.

Figure 111.16 shows actual and estimated costs, if still under construction, for total packages of production equipment over a wide range of capacities in the Gulf of Mexico and in the North Sea. It will be evident that these costs, for a given production capacity, can vary up to 30%. Production equipment costs for concrete platforms are considerably higher than production equipment costs for steel platforms because of the difference in construction methods. Production equipment and other facilities for steel platforms are constructed as modules, each module weighing not more than 1,000 tons so that it can be lifted and fitted into its place on top of the platform after having been transported to the platform location when the platform structure has been installed. In the case of a concrete platform, the production equipment and other facilities are constructed as one single package which is put on top of the concrete sub-structure, at the construction site, before the complete platform is being towed to its field location.

The range over which production equipment costs for a steel platform vary for a given capacity, has been divided into four smaller ranges to allow situational cost differentials as follows:

1. The production consists mainly of oil;

2. Oil will be produced with a substantial amount of gas which will be reinfected and/or transported to shore;

3. Mainly oil will be produced and the reservoir pressure will be maintained through water injection; and

4. Oil will be produced together with a substantial amount of gas which will be reinfected and/or transported to shore and the reservoir pressure will be maintained through water injection.

This subdivision was based on a more detailed assessment of relative costs for equipment required for gas transportation and/or reinfection and water injection. The largest part of these costs consist of pumps and gas compressors for reinfection and/or transportation purposes.

Platform Installation Costs

Platform installations can comprise 30% to 35% of the total platform costs in the case of steel platforms and 10% to 15% in the case of concrete platforms.

Steel jackets, such as the large ones used in the North Sea, will be towed out of the construction dock while floating on special flotation tanks, or will be loaded on a barge as in the case of the smaller jackets used in the Gulf of Mexico. The jacket will be towed to the installation site with the help of four to six ocean-going tugs, where the jacket will be put into an upright position while it is sinking to the bottom. A

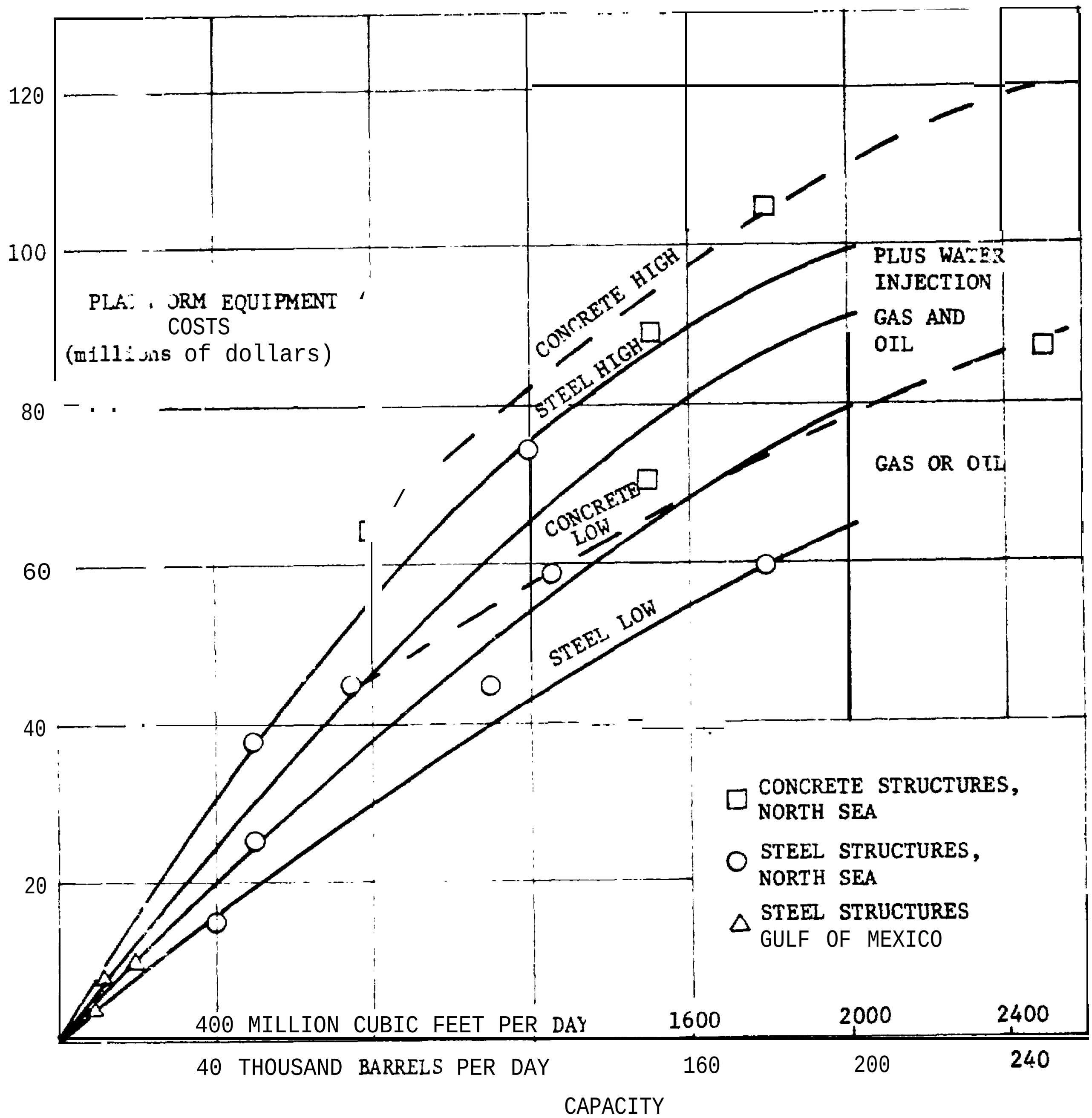

FIGURE 111.16 Costs of Platform Production Equipment and Facilities
(1975 $)

Source: Arthur D. Little, Inc., estimates.

temporary deck will be installed on top of the jacket, to accommodate the pile-handling units which will drive the piles used to fix the jacket firmly in its place. The temporary deck will be removed when the piling and grouting has been finished after which cap trusses will be installed followed by the deck modules weighing up to 1,000 short tons each with the help of a large derrick barge. When this is finished, the mechanical and electrical hook-up can take place.

This whole operation can take from four to six months, depending on weather conditions and unforeseen complications during the installation.

At least one derrick barge will be required on-site during the installation of the jacket and modules and it costs between $70,000 and $150,000 per day, depending on size. An example of the relative costs of the different types of support equipment and activities during installation of a platform is given in Table 111-11 where a breakdown is shown of the installation cost for a 125,000 barrel per day platform in 450 feet of water in the North Sea.

It is assumed that the installation costs for a platform will be between 30-35% of total platform costs if the platform is installed offshore the East Coast, offshore the West Coast or in the Gulf of Mexico. In these regions, suitable construction sites for steel platforms can be expected to be available within 500 miles from the areas where offshore oil or gas fields may be found. To allow for the greater distances to the different areas offshore Alaska, the transportation charges for the jacket and deck modules are calculated on a per-tonnage basis to increase the total installation costs accordingly.

b. Subsea Completions

Research and development work on subsea completion technology has been conducted since around 1964. Initially, the efforts were concentrated on the development of "wet Christmas trees" which would make possible the drilling and completion of wells in those parts of the oil or gas fields which could not be reached from the platform. The considerable increase in interest of the oil industry in development of offshore oil and gas fields and the availability of technology and engineering concepts developed for the space program resulted in the development of *dry* subsea completion systems. These provide an atmospheric working environment around the Christmas tree on the sea bottom, precluding special training of oil production personnel for routine service and maintenance work on individual wells. Reportedly, Exxon is working on a remotely controlled *"wet"* system.

TABLE 111-11

A BREAKDOWN OF PLATFORM INSTALLATION COSTS FOR JACKET AND DECK SECTIONS FOR A PLATFORM ACCOMMODATING A PRODUCTION OF 125 MB/D OF OIL AND, 200 MMCF/D OF GAS IN WATER DEPTH OF 450 FT.

	% of Total Costs
Temporary Work Decks[1]	3.0
Modify Barges	1.5
Derrick Barges	45.0
Cargo Barges	9.5
Tugs & Supply Vessels	10.5
Diving	7.0
Pile Handling Units	2.0
Grouting	0.5
Miscellaneous Installation	3.5
M&E Hook Up	16.5
NGL Installation	0.5
Storage & Handling	0.5
TOTAL INSTALLATION COSTS	100

[1]Used for platform piling.

Source: Arthur D. Little, Inc., estimates.

Figure 111.17 shows different elements of a typical "wet" subsea field development consisting of the subsea wellhead completions and a subsea manifold system which combines the production from various wells into one line, Through this line the production is delivered into treatment and separation equipment on top of a floating platform and from there into a tanker through a single-point mooring buoy. This type of system, which is now being used in a full scale development of the Argyll field in the North Sea in water depth of up to 420 feet, is operational to water depth of up to 1,200 feet. The development of a subsea production station, performing the functions now performed by the production station supported by the floating platform, will most probably take at least another eight to ten years, mainly because of difficulties to supply the power required to operate a production station on the bottom of the sea.

The economic incentive to use subsea completion systems rather than wells which are drilled, completed and serviced from a fixed platform, increases exponentially with increasing water depth. The advantages of subsea completion technology are many:

- It may allow the production of those parts of the field which cannot be reached from a fixed platform but which are not large enough to justify the installation of another platform.

- Subsea completions may be used to produce from appraisal wells at the initial stage" in the development of a large field before deciding on the exact plan for the full development of the field. This would offer the combined advantage of an early positive cash flow and of acquiring additional information about the reservoir characteristics.

- Potentially, one or more platform structures may be saved in the full development of a large field. Only one platform could be used to separate and treat the produced formation fluids. This platform would not necessarily be positioned on top of the field but could be installed in shallower waters close to shore.

- A number of smaller fields in deep waters could be developed, using a floating platform as production station, when investment in a large fixed platform cannot be economically justified.

When considering the costs of the completion of a subsea well and comparing these costs with those for a well completed on top of a platform, the following increases in costs for conditions such as those in the Gulf of Mexico can be identified:

- Higher well drilling costs because wells will have to be drilled using a jack-up or semi-submersible which will be more expensive than when drilling wells from a fixed platform.

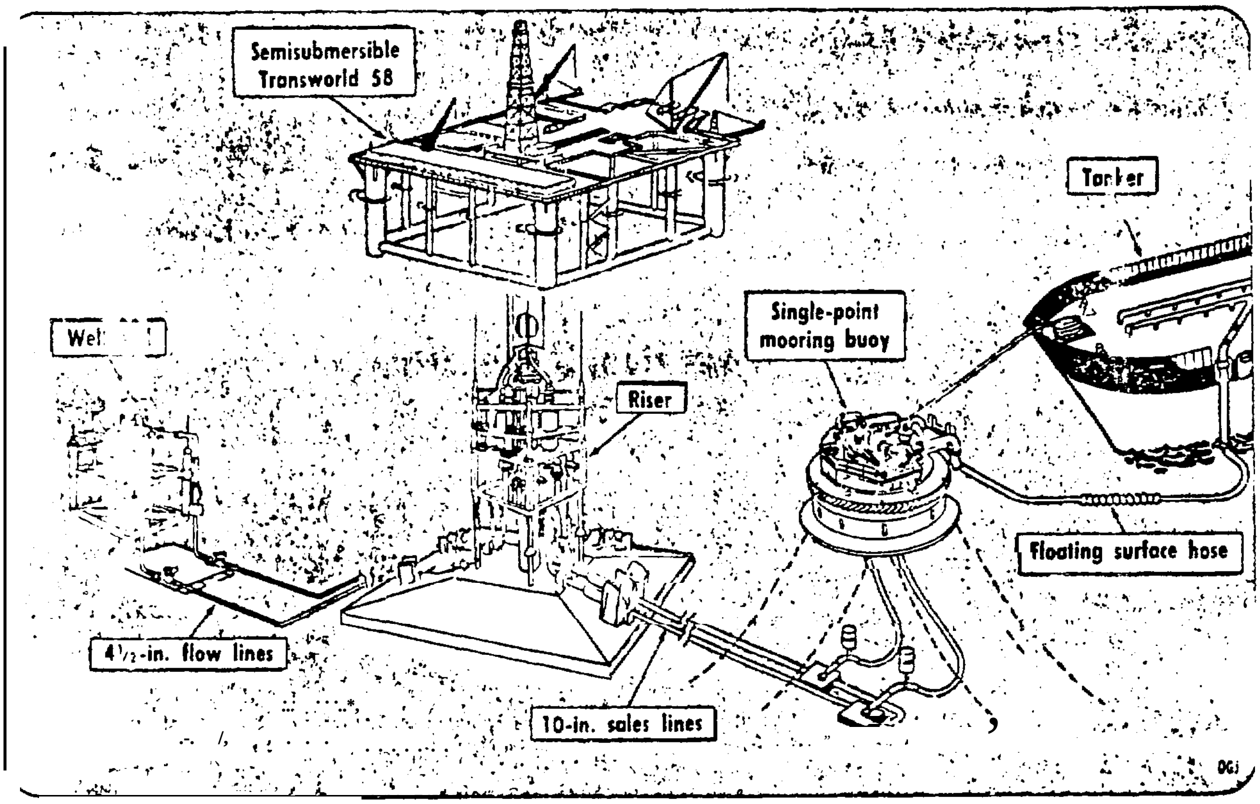

FIGURE 111.17 Subsea Completion System

Source: *Oil & Gas Journal*, November 1975 V.

- Additional equipment costs for the cellar* are estimated to be approximately three quarters to one million dollars for water depths up to 400 feet. For each additional 400 feet of water depth capability, the cost will increase between $50,000 to $100,000.

- The installation costs for the subsea completion using a special service ship which costs between $16,000 and $25,000 per day in the Gulf of Mexico. The same service in the North Sea costs between $32,000 and $50,000 per day.

- The cost of gathering lines and the cost of a subsea manifold adds another $200,000 to $300,000 to the total subsea completion cost.

The incremental subsea completion costs for North Sea conditions are generally estimated to be between 1.5 and 2 times higher than those for the Gulf of Mexico. The total incremental costs for a subsea completion for water depths of up to 1,200 feet in the Gulf of Mexico are estimated to range from 1.2 to 1.8 million dollars and for the North Sea to range from 2.1 to 3.3 million dollars per well. These estimates of incremental subsea completion costs are shown in Figure III.18 together with the platform construction and installation costs per well while assuming that each platform would accommodate 20 producing wells. On the basis of this comparison, subsea completions appear to become economically attractive in the Gulf of Mexico in water depths between 400 and 650 feet and in the North Sea in water depths between 2C0 and 300 feet. This clearly illustrates that the more severe the weather conditions and the deeper the water, the more attractive subsea completion technology will become.

In the analysis of minimum economic field size, the extent to which application of subsea completion technology might help to make otherwise submarginal fields economically feasible projects has been shown.

Transportation of Production to Shore

There are basically two ways to transport oil or gas to shore. A submarine pipeline can be laid from the particular oil or gas field to a receiving terminal onshore or tankers can be loaded on-site at the field which then transports the oil or gas to whatever receiving point might be most feasible.

*This is the capsule which accommodates values and connections controlling the outflow of the oil and/or gas streams,

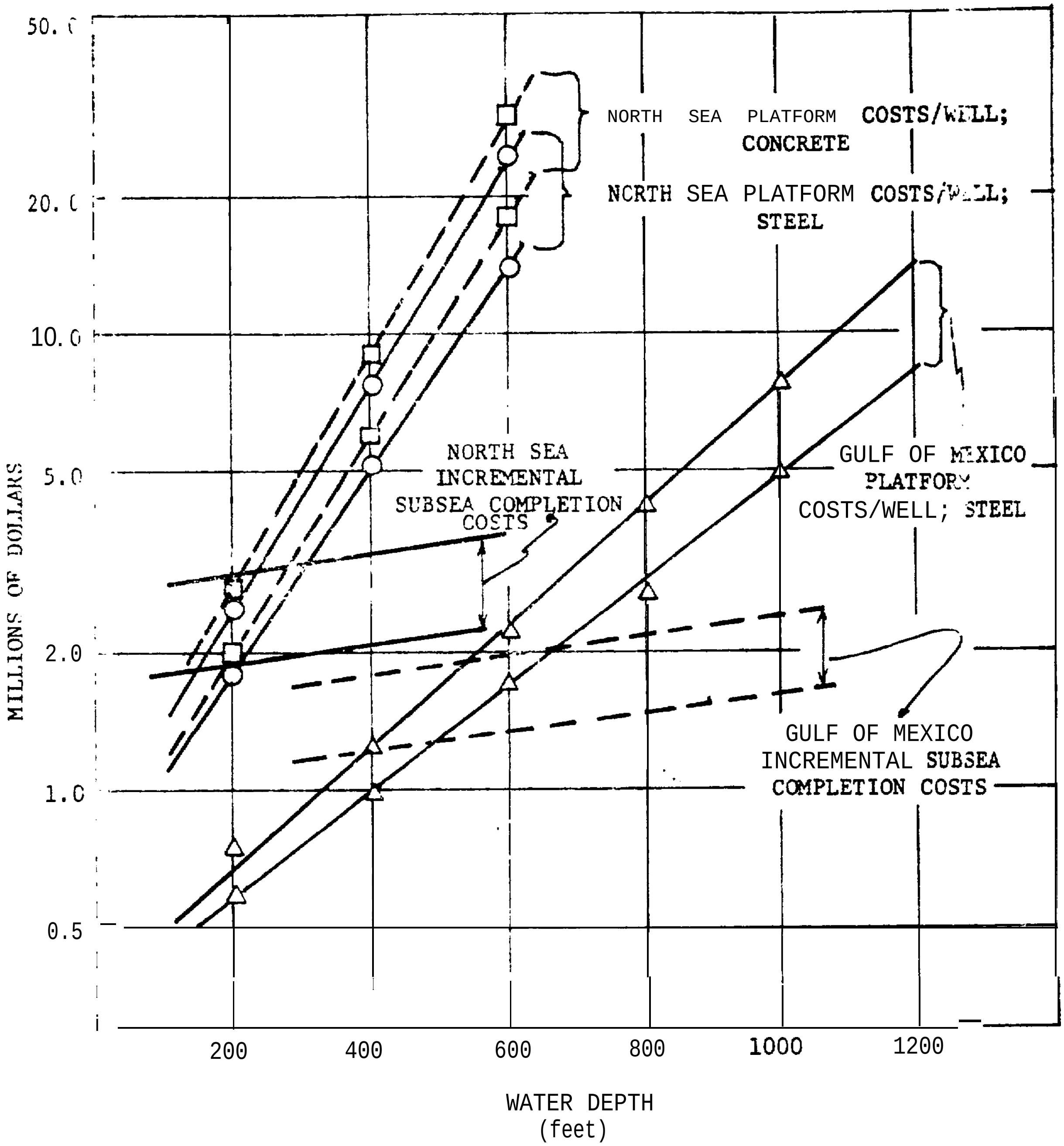

FIGURE III.18 Platform Fabrication and Installation Costs Per Well Compared with Incremental Subsea Completion Costs

Source: Arthur D. Little, Inc., estimates.

For natural gas, on-site liquefaction would be required to allow transportation by special LNG tankers. Both the liquefaction plant and the tankers require large capital investments, which under current price conditions would not be economically justifiable offshore the U.S.A. Also, loading LNG tankers on the high seas would require solutions to some very special technological problems, such as the design of a cryogenic flexible hose. Liquefied natural gas plants are now being constructed for use in the Persian Gulf and the Java Sea at the field site in offshore areas; the very calm waters in these areas greatly simplify the loading problems as compared with similar operation, for instance, in the Gulf of Mexico. Therefore, in the present analysis (of minimum economic field sizes) it is assumed that, so far, shipment of natural gas in the form of LNG cannot be considered to be feasible.

For oil, the alternative of shipment by tanker has been proven to be economically attractive under circumstances where economies of scale through use of large pipeline sizes to accommodate production of several fields cannot be used.

Pipeline Costs

Pipeline costs are broken down into material costs, pumping station costs, pipe-laying and burying costs, and costs for the shore approach. In general, it is expected that pipeline costs in dollars per mile will increase with increasing pipe diameter, weather severity, distance and pipeline water depth.

Pipe-laying operations have to be suspended when wave heights exceed a certain level. First-generation lay barges (see Figure 111.19) can only operate when waves are less than five feet; third-generation barges can continue operating at waves of up to 15 feet.

The diameter of the pipeline is mainly a function of the maximum throughput expected and the maximum pressure at which the oil or gas will be pumped. Figures 111.20 and 111.21 show optimum line sizes and their costs for a given distance as a function of maximum daily throughputs for oil and gas lines, respectively.

In the case of gas lines, where more pumping stations are required to move the gas over the same distance as for oil, the economics of the optimum line size can be changed considerably by foregoing a pumping station and using a larger diameter pipeline. The increase in material and laying costs of pipes are then offset by the decrease in pumping station costs for which an extra platform is also required.

Steel costs can range between $500 and $1,500 per metric ton for the steel depending on the diameter of pipeline, on the grade of steel used, and on whether standard pipe is used or not. Wrapping with tar paper and coating with 0.5 to 3 inches of concrete can cost between $50 and $150 per metric ton. Lay barges usually require adaptations for the

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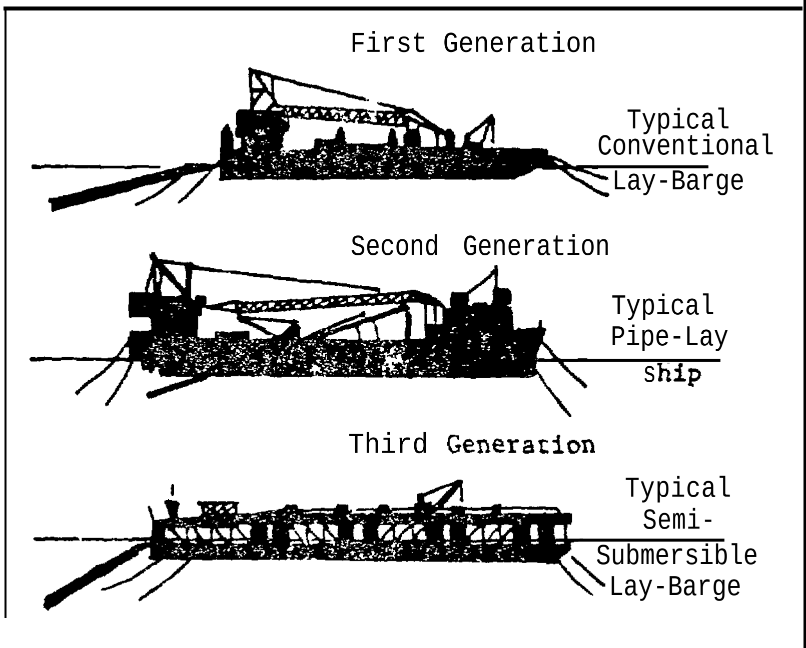
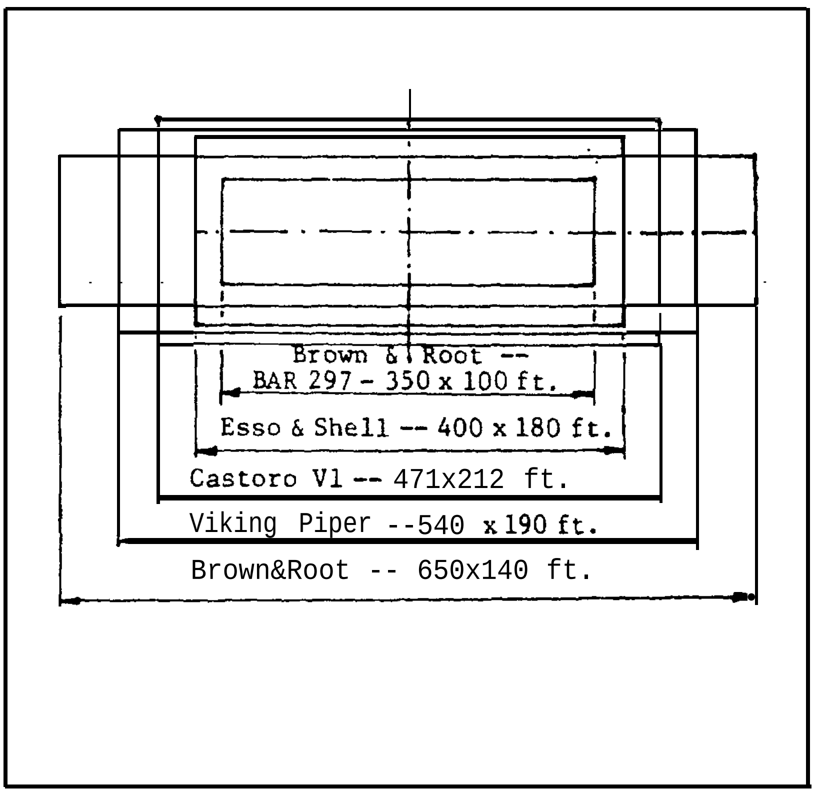


NORTH SEA LAY-BARGES (dimensions)



Source: *Oil & Gas Journal.*

FIGURE III.19 Pipelay Barges

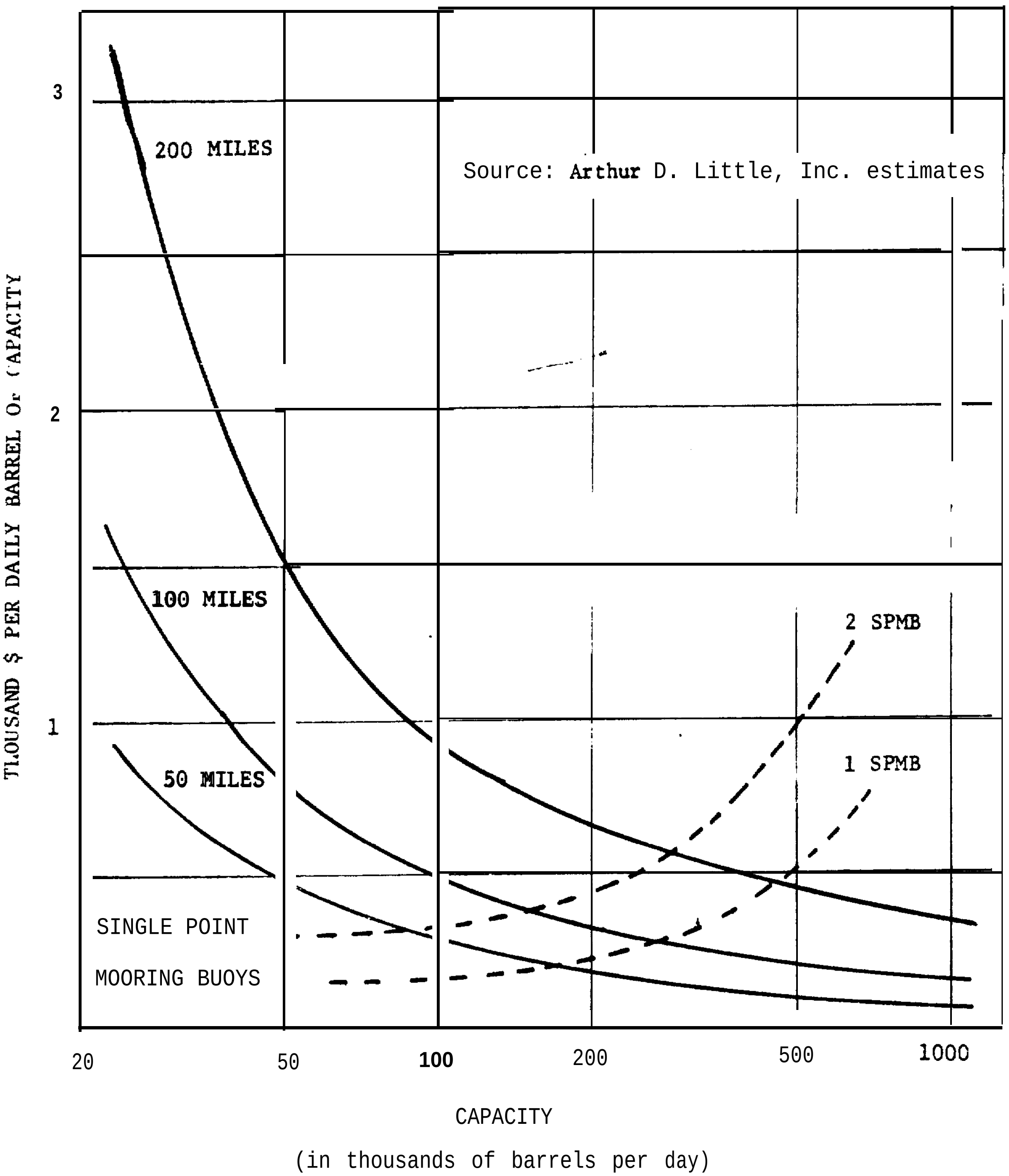


FIGURE 111..20 Oil Pipeline Coats as a Function of Capacity

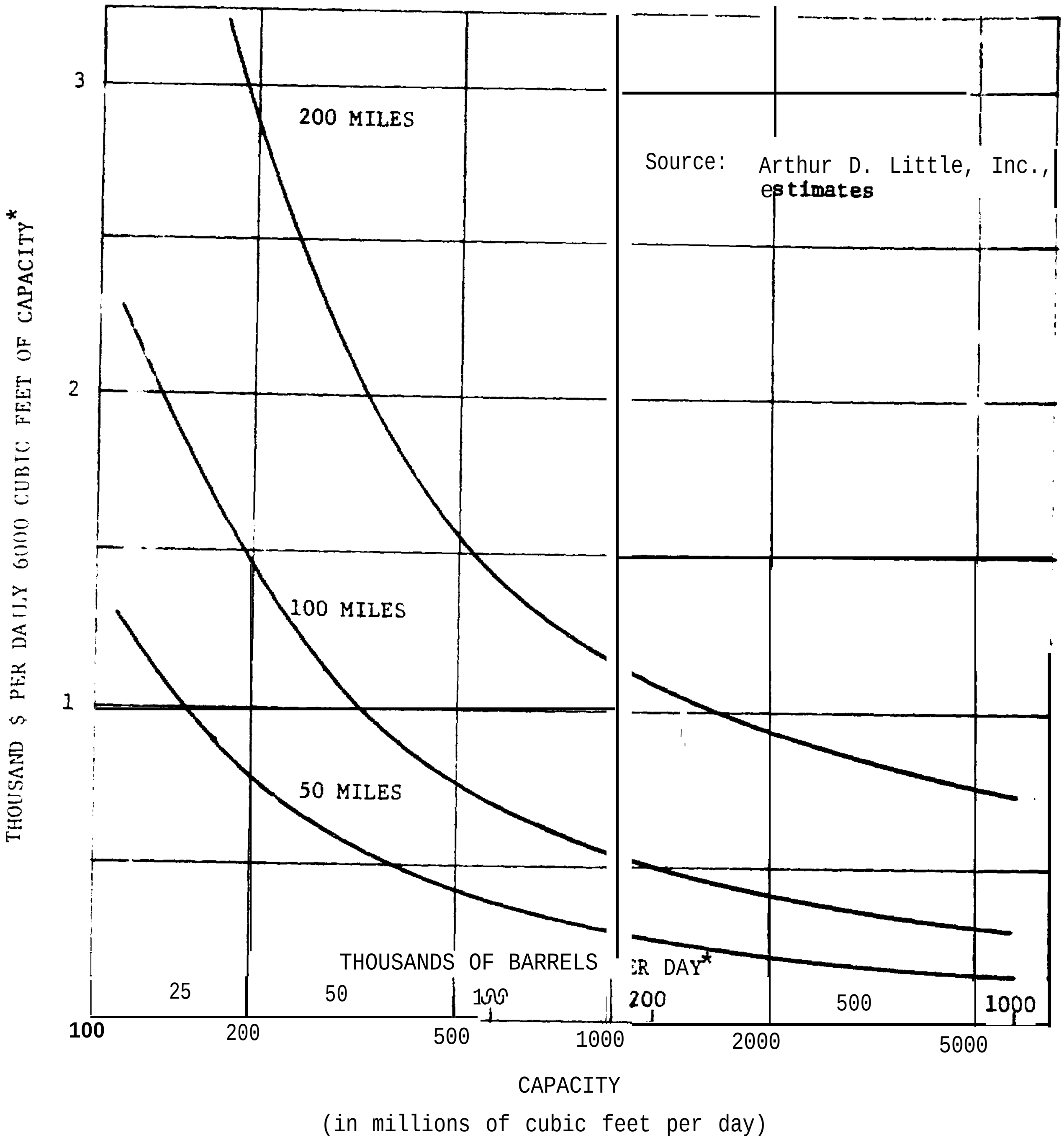


FIGURE III.21 Gas Pipeline Costs as a Function of Capacity
(1975 $)

*6000 cubic feet per day = 1 barrel per day of crude oil equivalent.

specific job which can cost up to three million dollars for the third-generation barges; mobilization and demobilization of the barge which, depending on the distance over which the. barge will have to be moved before it starts laying pipe, can be between $200,000 and two million dollars; daily costs for a lay barge, depending on whether it is first-, second-, or third-generation, will range between $70,000 to $170,000 per day; bury barges will cost between $60,000 and $100,000 per day.

The number of days that barges will be required to lay a pipe over a certain distance will be a function of (1) the good weather laying rate which currently is between one and two miles per day for diameters of up to 36 inches in water depths of up to 500 feet; (2) the weather down-time factor which, in the North Sea, is close to three, implying that the barge is waiting on weather or picking up abandoned pipe two out of every three days; and (3) the material maintenance factor which is usually taken to range between .65 to .75. The latter figures imply that inspite of maintenance work during weather down-time 25% to 35% of the good weather time still has to be used for maintenance activities which interfere with pipe laying.

Landfall or shore-approach costs are more complex to estimate because they are completely dependent on the shore conditions. Depending on whether the shore approach is a smooth, gently sloping, sandy beach or a rough, rocky coast with outcrops which require removal by underwater blasting, these costs can vary from $1 million to $12 million.

Figure 111.22 shows the range of line-mile costs for a 500,000 barrel-per-day line and a 50,000 barrel-per-day line when different assumptions are made for the distance-to-shore and the weather down-time factor. All four cost categories (materials, laying and burying, pumping stations, and shore approach) show a considerable range if we compare a low cost, 200-mile long line with a weather down-time factor of one with a high cost, 25-mile long pipeline with the weather down-time factor of four. Total cost for the 500,000 barrel-per-day pipeline are shown to range between .7 and 1.15 million dollars per line-mile while the total cost for the 50,000 barrel-per-day pipeline are shown to range from .25 to .75 million dollars per line-mile.

optimum combinations of pipeline size and number of pumping stations required for different line capacities over different distances and under different weather-laying conditions were calculated with the aid of a computer program. The results of the calculations for oil pipelines under what can be called typical North Sea conditions, with the weather down-time factor of three, are shown in the earlier referenced Figure 111.20. It is assumed in these calculations that the maximum line-size which can be laid is 42 inches even though the largest sized lines which have been laid to date are 36 inches. It is expected that laying of 42 inch line will be possible with the third-generation barges.

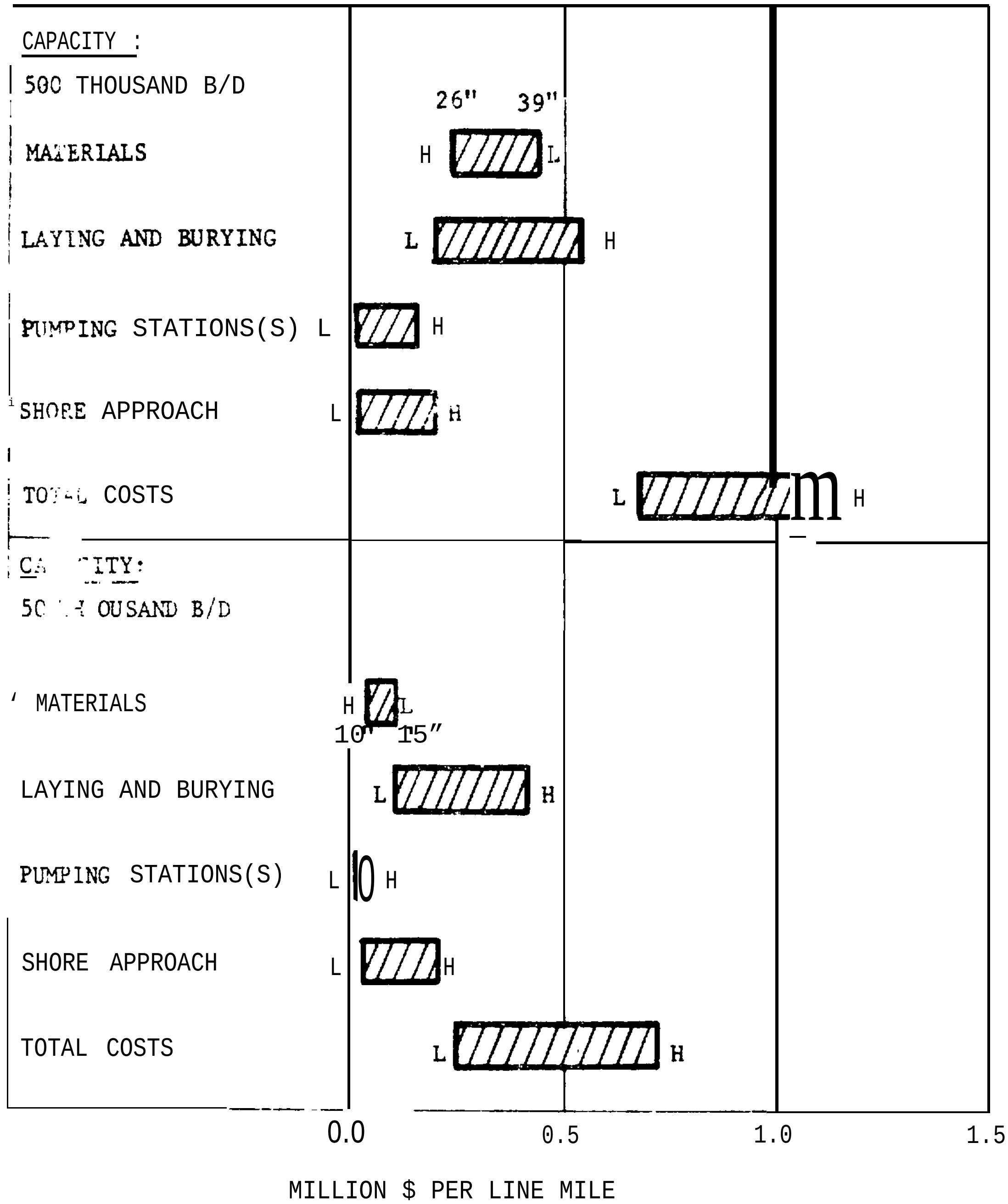


FIGURE 111.22 Range of Typical Pipeline Costs[1]
(In Millions of 1975 $)

[1]L: Pipeline 200 miles long, weather down time factor is 1.
H: Pipeline 25 miles long, weather down time factor is 4.

Assume : $500/MT steel, laying and burying $200 thousand per day, pumping station on production platform, shore approach $5 million.

Source: Arthur D. Little, Inc., estimates.

The importance of economies of scale in pipeline costs is clearly shown. A line with a capacity of 25,000 barrels over one hundred miles would cost close to $1,500 per daily peak barrel capacity to be compared with $200 per daily peak barrel if the line could be sized to accommodate 500,000 barrels per day of oil. . .

To obtain a comparison between the alternatives of oil transportation by pipeline and transportation by tanker, estimates of the costs for single-point mooring systems are shown in the same graph. The lower estimates shown are for a one-buoy system costing between $8 and $10 million which, in the production range of 50,000 to 100,000 barrels per day, would require loading from the platform straight into a tanker moored to the buoy . For a range above 150,000 barrels per day, costs for an extended loading single-point mooring buoy system were used. This system, costing between $35 and $40 million, has a storage capacity of 300,000 barrels which allows the field to continue production over a number of days if the tanker cannot link up to the buoy because of adverse weather conditions. A complete comparison of the various types of transportation systems requires analysis of cash flows which also allows for operating cost differentials. This analysis is performed in the analysis of minimum economic field sizes.

The results of similar analysis of the total costs for gas pipelines are shown in Figure 111.21. The same assumptions were made about materials and laying costs," shore approach costs, and the weather down-time factor. From the results, it will be apparent that investment in the required pipeline will have to be about 25% higher if the same amount of BTU's are to be transported over the same distance in the form of gas instead of in the form of oil.

Tanker Costs

The decision to link an offshore field with shore-based facilities by tanker, rather than through a pipeline, will be based upon considerations of field size (i.e., maximum number of years of production), production rate, cost of buffer storage, cost of pipeline construction, distance-to-shore, and onshore facilities at landfall. Since the OCS areas are rather large, substantial variations may occur in actual distances to be travelled, depending on the location of the well within the area and upon the distance to the nearest receiving terminal. The transportation from western and northern Alaskan fields, OCS areas 14 through 17, warrants special considerations: Are pipelines feasible for part of the -rip, i.e., to southern Alaska, or should tankers be considered exclusively? As part of the data base for this study, the costs of oil transporation by tanker from offshore locations to continental U.S. ports have been estimated.

The transpiration cost of crude oil by tanker can be expressed as a .nction of the distance travelled, the size of the tanker, and operating :: parameters of the site considered. These cost parameters vary the flag of registration and with the year of construction and the year of operation of the tanker. Flag of registration for tankers operating between the U.S. Outer Continental Shelf and U.S. ports is, of necessity, the U.S. flag (Jones Act). This implies that all cost parameters that depend upon the registration of the vessel, such as crew costs and insurance costs, have to be calculated for U.S. conditions. The year of ship construction determines the all important yearly capital charges. Due to inflation in ship construction costs, older ships tend to be cheaper than new ships, hence, older ships show smaller capital charges than their younger sisters. We have assumed that new ships will be used, i.e., we have made a conservative, high estimate of tanker transportation costs.

The buildup of tanker costs is such that they are almost a linear function of distance travelled for any one ship size. Deviation from exact linearity is due to variations in payload for varying distance since long,.. distances require more bunkers to be carried, reducing cargo carrying capacity. Hence, deliverability is a function of distance travelled and the cost-per-ton of delivered oil increases slightly more than proportional with the length of the voyage. The other variable, ship size, gives rise to the well-known economies of scale in shipping, whereby costs-per-delivered-ton decrease disproportionately with the size of the tanker up to a size of approximately 250,000 dwt.

Figure 111,23 is indicative of the relationship between cost and distance and cost and ship size, respectively.

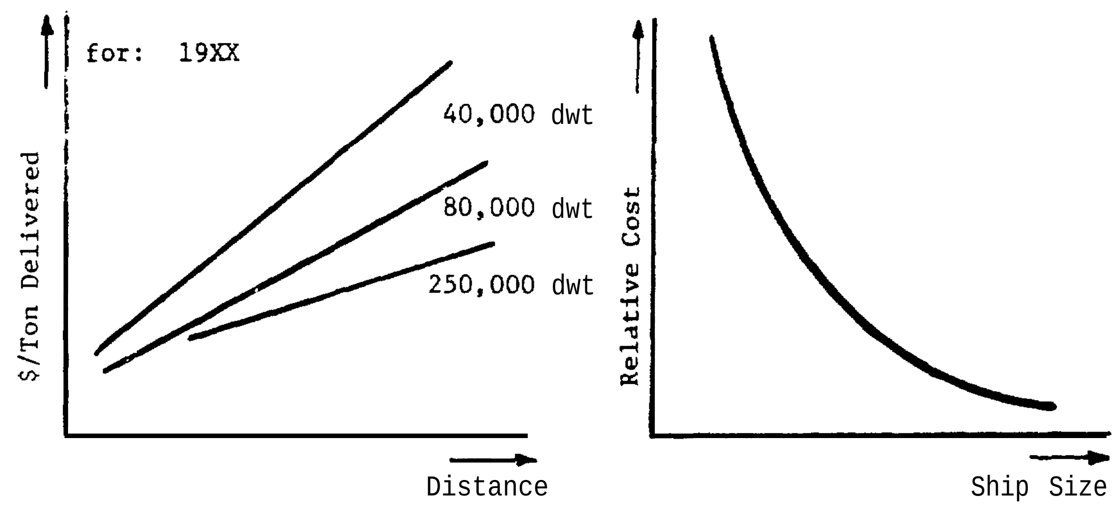


FIGURE 111.23 Shape of Functional Relationships Between "$/Ton Delivered''/and "Distance" and "Relative Cost" and "Ship Size"

For the purposes of this study, we decided to **calculate shipping costs** for voyages of various **lenghts** and for a selected number of vessel sizes below 150,000 dwt, the largest size that can be handled by a port and probably larger than the largest tanker that will be used on a shuttle service between offshore production and receiving terminals. With these calculated costs, graphs have been constructed (see Figures 111.24 and 111.25) that show delivered crude oil costs as a function of distance **travelled** one-way, with the ship size as a parameter. Ship sizes not shown can be interpolated between those for which costs are given. These graphs enable the rapid determination of tanker transportation costs on any OCS **route** for any tanker size considered.

The transportation costs associated with each ship **size/distance** combination are considered to have two basic components:

- fixed costs and
- voyage costs.

The fixed costs of a tanker are independent of the trade she plies; the **voyagecosts depend upon** both the tanker and the specific voyage considered and have two basic components: bunker costs and port charges. Bunker consumption data used in this analysis assume steam turbine propulsion units, the dominant source of power for U.S. flag tankers. Bunker costs have been estimated at $67.50/long ton in 1975.

Port charges have been assumed nil at the loading ports, i.e., at the **OCS** locations; port charges at unloading ports, have been taken as the average for U.S. ports. It should be noted that port charges on a yearly basis tend to become significant for the short voyages from most **OCS** locations.

All fixed **costs** are stated in **terms** of 1975 dollars and the estimates made take into account current operating and financing practices in the US. Operating practice **is** assumed at a level which might be encountered with a major **oil** company.

The following fixed costs have been considered:

- *Crew Costs.* These are as calculated by **MARAD,** Maritime Administration of the Department of **Commerce** using a computer **image** program **which** takes into account details of a reaming complement including overtime and fringe benefits. New wage contracts that went into effect on June 16, 1974 and June 16, 1975 have been taken into account.

- *Insurance Costs.* These have been calculated from estimates **of** three **components:**

    a. Hull and machinery insurance; covers accidental damage to the vessel,

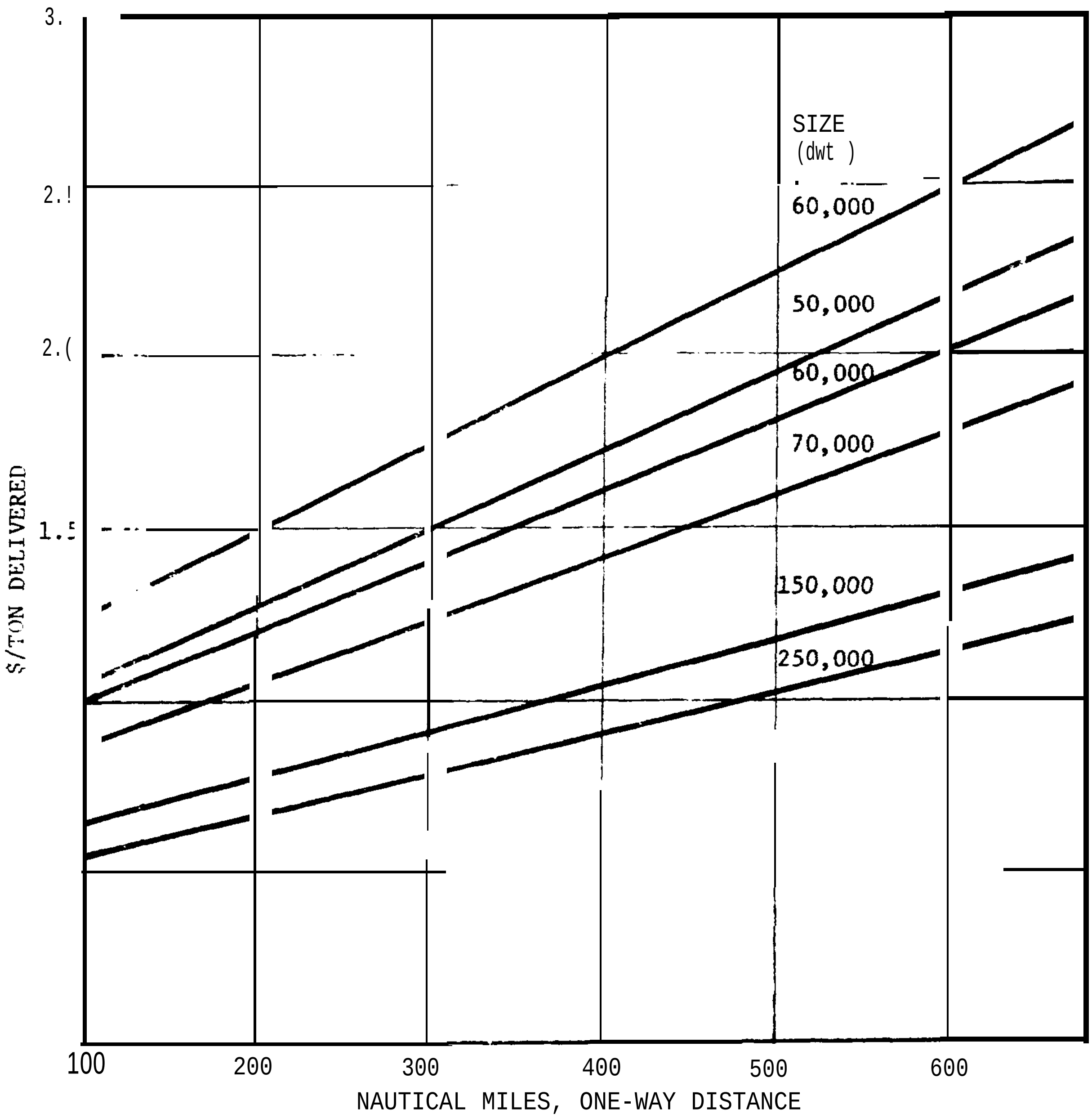


FIGURE III.24 Total Cost of Crude Oil Transportation in U.S. Flag Vessels in 1975 for Tanker Voyages of Less Than 1000 Nautical Miles One-Way

Source: Arthur D. Little, Inc., estimates.

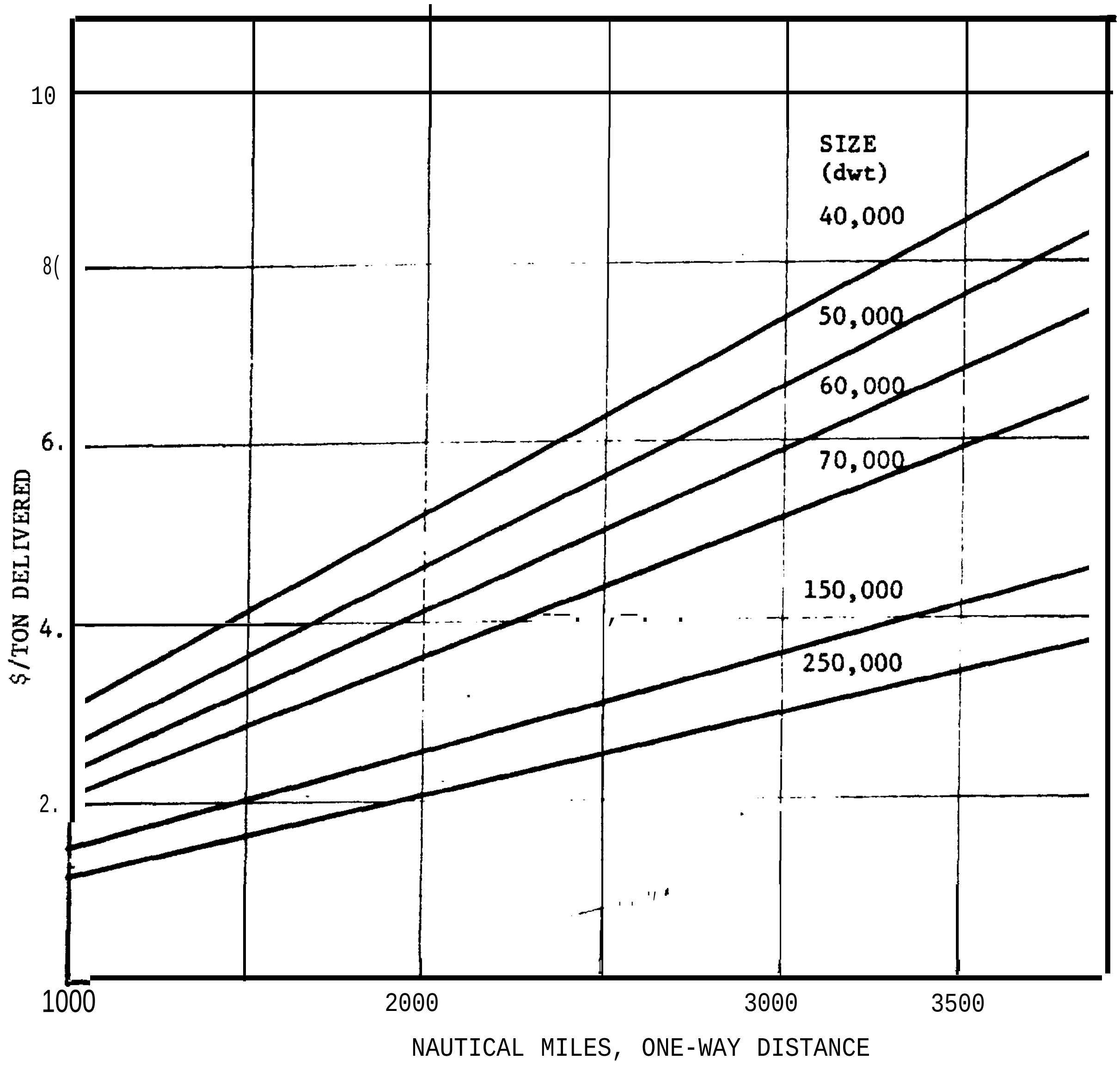


FIGURE 111.25 Total Cost of Crude Oil Transportation in U.S. Flag Vessels in 1975 for Tanker Voyages Up to 5000 Nautical Miles One-Way

Source: Arthur D. Little, Inc., estimates.

b. Protection and Indemnity insurance; covers such risks as injuries to crew or shore personnel, damage to third-party property, damage to cargo, oil pollution, etc. Most of this type of insurance is written through mutual ownership clubs, "P&I" clubs .

c. Total loss insurance; covers the risk of losing the vessel.

- *Maintenance & Repair Costs.* These are calculated for the ship's mid-life year and assume a practical level of ship upkeep. Insurance costs reflect fleet operations with a reasonable history of claims and average levels of deductibles. The latter are included in the M&R costs.

- *Capital Costs.* These have been based upon a review of published prices for delivered and on order tankers from U.S. yards. The reported costs have been increased by 10% to allow for such costs as interest during construction, financing fees, legal and accountancy costs, etc.

- *Miscellaneous Costs.* These include four principal items: shore overhead, stores, lubricating oils and equipment rentals.

Some other operating parameters that have been taken into account are, for example: a vessel speed of 16 knots, port times of 1.5 days, vessel availability of 350 days per year, etc.

Figures 111.24 and 111.25 show the results of the calculations. The latter have been made with the aid of a computerized tanker cost model. Table 111-12 shows average distances and transportation costs in cents-per-long-ton and in cents-per-barrel for selected voyages from offshore areas to onshore terminals. The transportation costs for LNG from Alaska (Point Gravina) to Los Angeles have been estimated at $1.00 per MM BTU, in accordance with a recent study* done on the subject and assuming an internal rate of return of the LNG project of 15%.

Terminal Costs

For oil, the onshore terminal consists of a tank farm providing buffer storage capacity and a desulfurization and desalinization plant, if required. The investment costs on a per barrel per day basis for the desulfurization and desalinization plant are relatively small, around

* Department of the Interior "Alaskan Natural Gas Transportation Systems" Economic and Risk Analysis by The Aerospace Corporation, Draft of June 1975.

TABLE III-12

CRUDE OIL TRANSPORTATION COSTS FROM
OCS AREAS TO LIKELY MARKETS (1975 DOLLARS)
(transportation costs in C/long tons[1] and
distances in nautical miles [n.m])

From \ To	New York (50,000 dwt)		Galveston (50,000 dwt)		Long Beach (150,000 dwt)		Seattle (150,000 dwt)	
	¢	n.m.	¢	n.m.	¢	n.m.	¢	n.m.
North Atlantic	150	300	495	2100	n.a.		n.a.	
Middle Atlantic	140	250	445	1850	n.a.		n.a.	
South Atlantic	220	600	335	1300	n.a.		n.a.	
Gulf of Mexico	445	1850	150	300	n.a.		n.a.	
California	1090	5100	990	4600	105	400	160	1000
Washington/Oregon	1180	5600	1090	5100	185	1000	120	500
Gulf of Alaska	n.a.		n.a.		300	2300	185	1250
Bristol Bay	n.a.		n.a.		310	2400	275	2050
Bering Sea	n.a.		n.a.		470	3900	360	2850
Chukchi Sea	n.a.		n.a.		490	4100	380	3050
Beaufort Sea	n.a.		n.a.		n.a.		n.a.	

Source: Arthur D. Little, Inc. estimates.

[1]Conversion: 1 long ton ≅ 7.5 barrels.

$6 to $10 per daily barrel capacity. These costs can be assumed to fall within the range of accuracy of any of the other major investment estimates for the development of offshore fields and are excluded explicitly from the analysis.

The tank farm, however, requires a significant capital outlay. For a typical-sized tank farm anywhere along the coast of the U.S. In the lower 48 states, the investment can be between $200 and $400 per peak daily throughput capacity. A tank farm constructed anywhere along the coast of Alaska will be more expensive because of higher costs for materials and construction, which will result in increases of between 10% and 20% of the costs for tanks, tank farm piping, miscellaneous equipment, and land development. The costs for the tank farm in a given location will depend on the number of day's supply the tank farm is expected to accommodate, the type and size of tanks used, and the type of dikes used around the tanks. For instance, several states require steel dikes around the tanks instead of the cheaper earthen dikes which can result in a significant cost increase for the total tank farm.

Assuming a required capacity of 30 days of crude supply, a tank turn-over factor of 5.7, an average tank size of 500,000 barrels per day, steel tanks with a floating roof, and every four tanks surrounded by an earthen dike results in estimates of $199 to $245 per barrel per day throughput capacity, depending on the overall size of the tank farm. Operating expenses range between 3.16¢ per daily barrel for the largest sized tank farm to 3.33¢ per barrel for the smallest sized tank farm.

The graphs in Figure 111.26 show investment and operating cost changes as functions of throughput.

3. Operating Costs

Operating costs will vary considerably for different platforms even if their capacity is the same. These costs depend on operating procedures and standards for the particular company, the reservoir characteristics, and the distance to the nearest supply base.

Based on an analysis of actual operating costs for the Gulf of Mexico, the Cook Inlet in Alaska and the North Sea, the operating costs calculation is categorized into fixed costs, which can be assumed not to change for a given platform over its producing life, and into variable costs which will vary with the volume of oil and/or gas produced and the volume of water and/or gas injected into the reservoir. Fixed costs are divided into the following categories:

- Wages and salaries,
- Provisions and catering,
- Transportation to-and-from the platform,

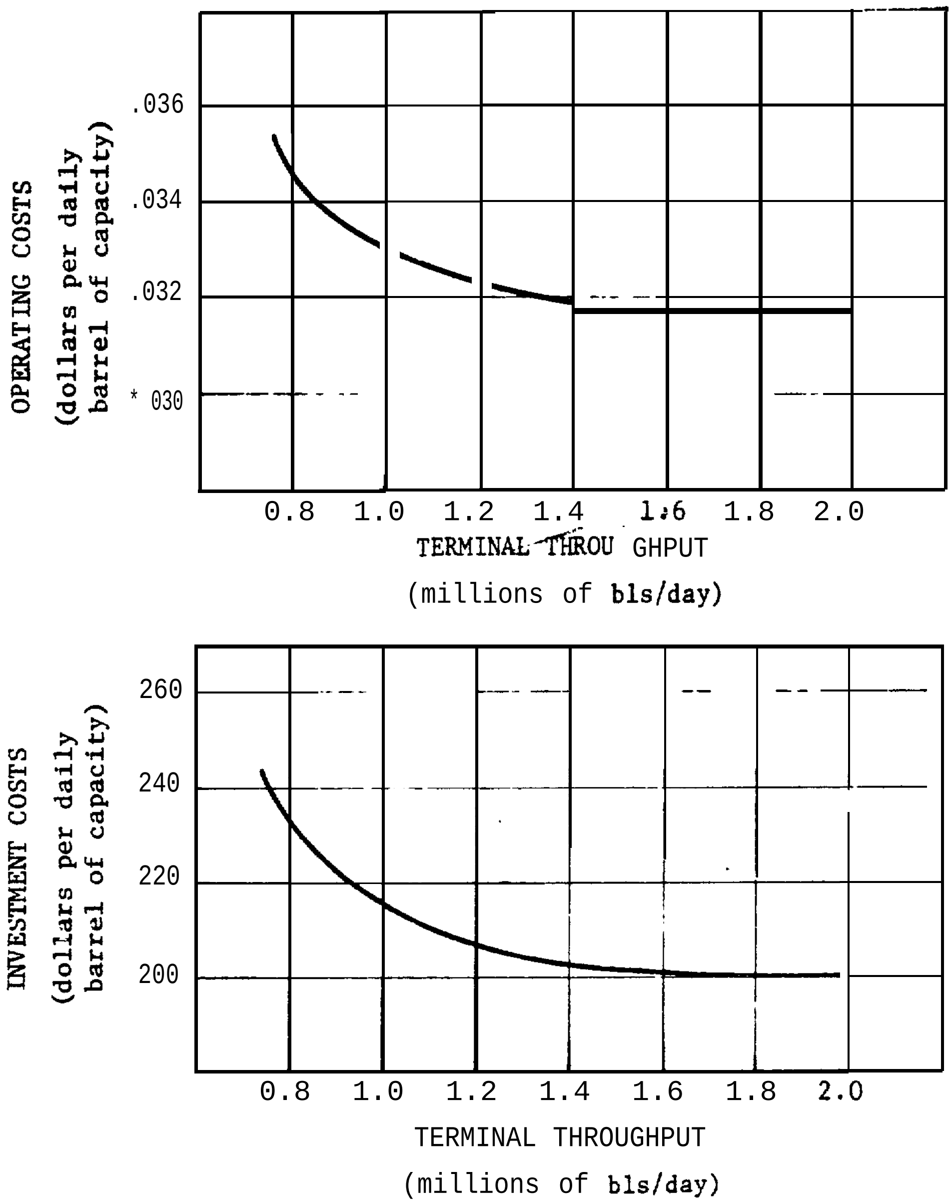


FIGURE 111.26 <u>Crude Oil Tank Farm Investment and Operating Costs as a Function of Throughput Capacity</u>
(1975 $)

Source: Arthur D. Little, Inc., estimates.

- Well workovers,
- Miscellaneous equipment maintenance,
- Insurance,
- Maintenance of electrical equipment, and
- Overhead and contingencies.

Wages and salaries, including payroll overhead were found to be the same for the Gulf of Mexico as they are for the East and West Coast areas offshore the Continental United States, Catering and quarters prove to be of the same order of magnitude per man-day as the cost of a first-class hotel in a major city,

Costs for transportation (by boat) of supplies and personnel will be similar all along the coast of the mainland , except for some areas where larger than average boats may be required. In those areas where frequent, and long, supply interruptions may be expected, the cost of larger-than-average supply vessels may be 20% to 25% above comparable costs in the Gulf of Mexico.

Expected costs for supply and personnel transportation (by helicopter) in areas offshore Alaska are still higher; helicopter charter time for work in Alaska is quoted as three to five times as high as the costs for comparative services in the Gulf of Mexico.

Well workover costs during the production period are a very significant factor in oil production economics, both on-and offshore. They can range from several tens of thousands of dollars for small wells in the Gulf of Mexico to several hundreds of thousands of dollars for large wells in the rough environment of the North Sea. Wells located off the U.S. Atlantic and Pacific Coasts will show workover costs similar to those for wells in the Gulf of Mexico of comparable size. However, workover costs offshore Alaska are expected to be in the same range as workover costs in the North Sea, that is, at least 40% to 60% above those costs for wells in the Gulf of Mexico. Industry estimates the workover costs for subsea completions to be as much as 2.5 times those for conventional wells completed off a platform.

Miscellaneous equipment and its attendant maintenance are shown to be relatively constant percentages of the total cost of main platform equipment over a wide range of platform sizes. Yearly insurance is estimated at 2% of total capital investment in a platform. Costs of power plant maintenance can, quite consistently, be considered as a fixed amount per installed horsepower, which is directly related to the expected peak production capacity of either oil or gas.

Variable production costs comprise mainly energy and maintenance costs for oil pumps and gas compressors. The following variable costs are included in the analysis:

- those directly related to oil production,
- those directly related to gas production,
- maintenance cost of gas injection equipment,
- gas injection operating costs,
- maintenance cost of water injection equipment, and
- water injection proper.

Directly related production costs for both oil and gas are proportional to daily produced volumes of oil and gas. Gas compressor maintenance costs are a function of the installed compressor capacity which, in turn, is determined by gas flow and required compression ratio.

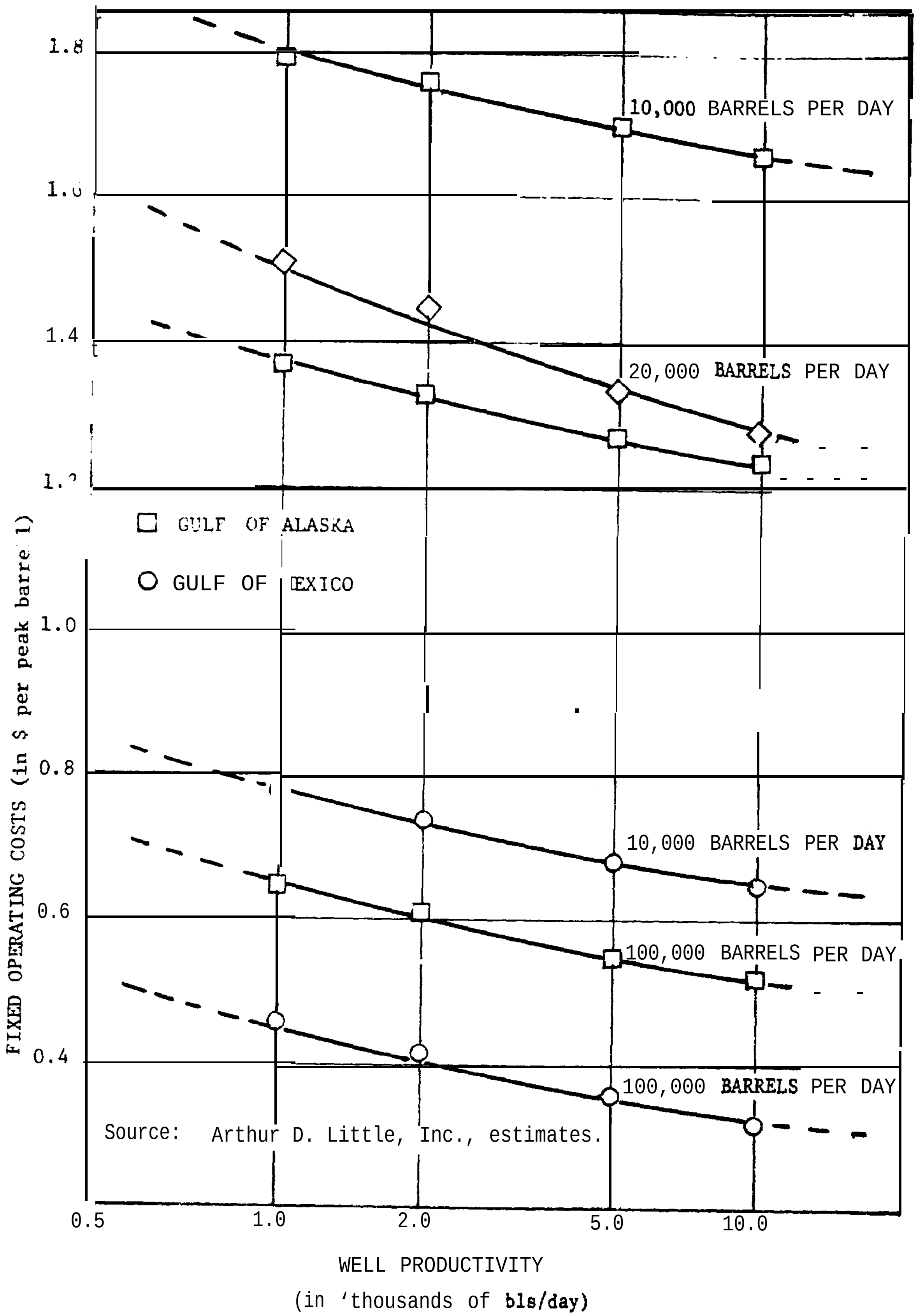
The number of production personnel required on a platform is a function of the platform's peak capacity, ranging from 15 men on a small platform to almost 100 men on large platforms.

All cost elements are incorporated in a computerized operating cost model which allows for changing costs with changing well productivities and changing platform production capacities in various offshore axeas.

Figure III.27 is an illustration of fixed operating costs as a function of well productivity calculated for platforms with a productivity of 10,000 and 100,000 barrels per day in Alaska and in the Gulf of Mexico. For comparison purposes, the fixed operating costs of two 20,000 barrel-per-day production systems are included as well, one with subsea completion and one with conventional platform completion.

Annual pipeline operating cost has been assumed at 2% of the initial investment plus $20 to $30 per installed horsepower in pumping stations.

FIGURE III.27 Fixed Operating Costs as a Function of Platform Capacity
(In 1975 $)



IV. THE ANALYSES

A. ANALYSIS OF FIELD ECONOMICS

1. Overview

The expected costs of exploration, development and production of specific fields in the different OCS areas have been calculated based on the technical costs (presented in Section III.C) as a function of the individual sizes and number of fields expected for these different OCS areas and by using the methodology described in Section II.

Investment costs and annual production costs by field size were determined in total and per daily unit produced. Costs were broken down into the following categories:

- exploration drilling costs,
- platform construction and installation costs,
- development well drilling costs,
- platform equipment costs,
- pipeline installation costs,
- gathering system costs, and
- onshore terminal costs.

To allow for cost differentials resulting from differences in weather and environmental conditions for the 17 different OCS areas of the Bureau of Land Management's classification, these areas were divided into eight groups (see Figure IV.1):

- The Atlantic Coast area comprising BLM areas 1, 2, and 3;
- The Gulf of Mexico area, comprising the eastern, central and western areas of the Gulf of Mexico;
- The southern Pacific Coast area, comprising southern California borderland and the Santa Barbara channel;
- The northern Pacific Coast area, comprising northern California and Washington-Oregon;
- The Gulf of Alaska;
- Lower Cook Inlet and Bristol Bay;

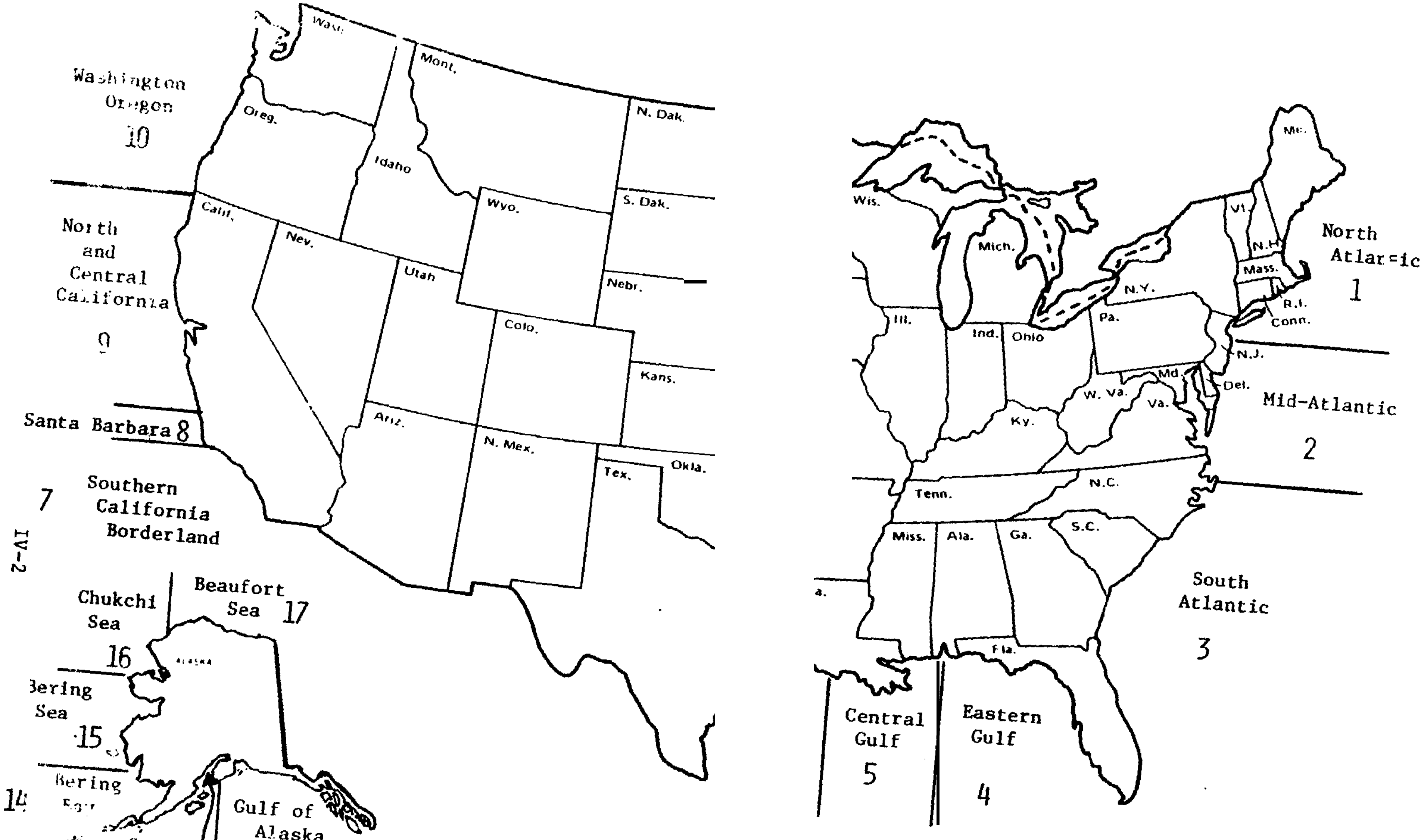


FIGURE IV.1 Map of the Locations of the Outer Continental Shelf Areas

- Bering Strait and the Chukchi Sea; and
- The Beaufort Sea.

Minimum Required Price schedules were constructed based on the cash flows resulting from the cost calculations and allowing for royalty and tax payments in order to obtain an indication of what field sizes can be expected to be marginally economical under certain future cost/price conditions (see Figures IV.8 and IV.9).

Each calculation required the specification of basic parameter values for:

- well productivity,
- water depth, and
- distance to shore,

Average well productivity was assumed to be 500 barrels per day for oil and 20 million cubic feet per day for gas in the areas in the Gulf of Mexico and 2500 barrels per day for oil and 50 million cubic feet per day for gas in other OCS areas. The water depth and distance-to-shore representative for the different areas was taken from the Environmental Impact Statement* which shows potential drilling sites for each of the 17 areas.

To show how the Minimum Required Price Schedules can be expected to change with different values for the basic parameters, sensitivity tests were performed for the Gulf of Alaska, changing the values of the parameters over the ranges shown in Table IV-1. (See Figures IV.10 and IV.11 for the results of these sensitivity tests.)

TABLE IV-1

MINIMUM REQUIRED PRICE CALCULATIONS
SENSITIVITY TESTS:
PARAMETRIC VALUES

	Water Depth (feet)			Distance to Shore (miles)			Well Productivity Oil (B/D)			Well Productivity Gas (MMCF/D)			Required Rate of Return (%)		
	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
Gulf of Alaska	200	400	700	5	25	50	500	2500	10,000	20	50	100	10	15	25

*United States Department of Interior: "Final Environmental Impact Statement Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf."

The cost calculations for the base cases and for the sensitivity tests were done assuming field development from a fixed platform. To show how the costs can be expected to change with alternative types of field development for oil producing fields, Minimum Required Price schedules were also developed for fields developed with subsea completions and a floating production station using a single-point mooring buoy and tankers to transport produced oil to shore.

2. Total Costs for Exploration and Development for Individual Fields

As mentioned In the previous sections, an analysis of the costs which are required for exploration and development of individual oil and gas fields in the different OCS areas must allow for changes in costs caused by differences in overall conditions. Within a particular area, the costs between individual fields can still be expected to vary significantly because of differences in:

- The water depth at the location where the field has been found resulting in differences in platform construction, installation, and in pipelaying costs;
- The distance to shore, which will affect pipeline costs;
- The physical dimensions of the field, which will affect the development program, i.e., the number of platforms for a given amount of recoverable reserves. The amount of reserves that can be produced by one platform depending on how deep the producing horizon is and-on whether the producing formations are thinly spread out over a larger area or whether they are thick, which makes it possible to produce more of the reserves with the same platform;
- The production characteristics of the reservoir itself which can affect the number of development wells which must be drilled, depending on the average well productivity and on the requirement for injection wells for water flooding;
- The quality of the oil or gas which can affect the amount of processing equipment required on the production platform, depending on how much stabilization and separation is required before the oil and/or gas can be transported to shore and whether associated gas has to be reinfected into the reservoir or has to be flared.

None of the values of these parameters, which all impact on the overall costs of field development, are known with certainty at the exploration stage. Therefore, a set of representative estimates are selected as base case values for water depth, distance to shore, and well productivity for the different areas as shown in Table IV-2.

TABLE IV-2

BASE CASE PARAMETERS

		Water Depth[1] (feet)	Distance to Shore (miles)	Well Productivity Oil (B/D)	Well Productivity Gas (MCF/D)	Years Delay[2]
1.	Atlantic Coast	400	75	2500	50	4
2.	Gulf of Mexico	400	75	500	20	3
3.	Pacific	600	15	500	50	4
4.	Gulf of Alaska	400	25	2500	50	5
5	Lower Cook Inlet, Bristol Bay	200	15	2500	50	5
6.	Bering Sea, Chukchi Sea	200	75	2500	50	5
7.	Beaufort Sea	300	15	2500	50	5

[1]This study oniy considered areas with a water depth not exceeding 600 feet (i.e. the strict definition of the Outer Continental Shelf).

[2]Years delay from first discovery well till first production.

Source: Arthur D. Little, Inc., estimates.

Apart from the Gulf of Mexico and offshore California, where the average well productivity for oil and gas producing wells is approximately 500 barrels per day and 20 and 50 million cubic feet per day, respectively, base case values have been selected to be 2500 barrels per day for oil and 50 million cubic feet per day for gas as the average for the other areas.

The values chosen for representative water depth and distances to shore for the different areas were based on information contained in the Environmental Impact Statement* which also shows the location of the most likely drilling sites for the different areas (see Appendix B).

The physical field dimensions, production characteristics and quality of the oil and/or gas were assumed to be the same fcr all OCS areas. Consequently, calculations of total development and production costs were based on the assumption that similar fields, in terms of recoverable reserves, water depth, distance to shore, depth of producing horizon, and reservoir production characteristics, would require the same number of development wells and the same number of platforms with similar production equipment on those platforms in order to produce the fields. The only difference between otherwise similar fields, as shown in Table IV-2, are the different lead times between the first discovery well and the beginning of field production. These periods vary from three years for the Gulf of Mexico to five years for offshore Alaska. This assumption allows for differences in working conditions, a shorter working season In Northern and Polar areas, and longer distances from major supply centers.

In total exploration, development and production costs, the different areas, starting with the most costly one, rank as follows:

- the Beaufort Sea and the Chukchi Sea,
- the Gulf of Alaska,
- the Bering Sea and the Bristol Bay,
- the Lower Cook Inlet,
- the Atlantic Coast,
- the Gulf of Mexico, and
- the Pacific coast.

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*United States Department of Interior: "Final Environmental Impact Statement Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf".

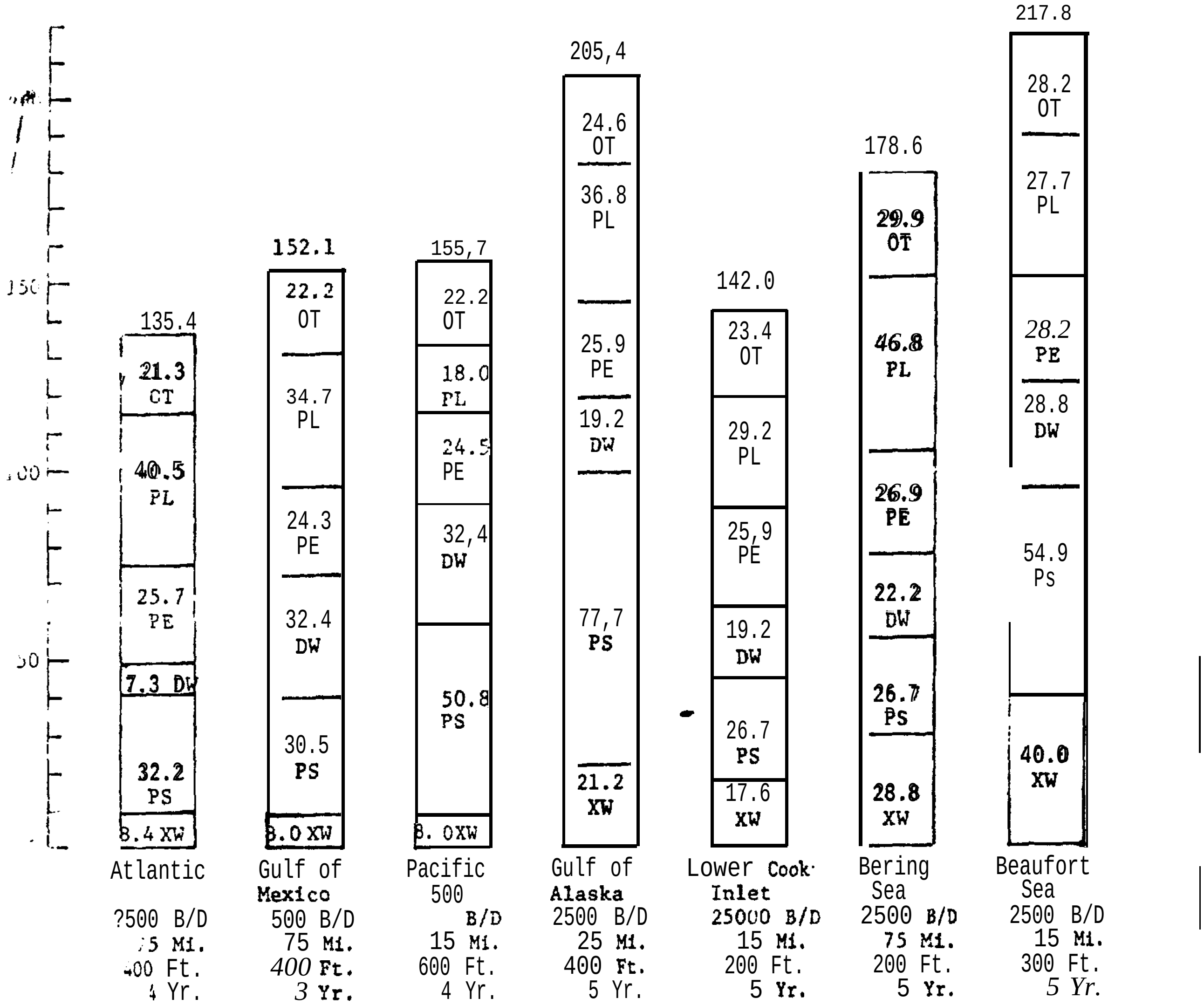
If water depth, shore distance, and average well productivity were the same for all areas, total costs in the most expensive area, the Beaufort Sea, would be approximately five times as expensive as in the least expensive area, the Pacific.

When expected differences in water depth and distance to shore between the areas are considered, the expected costs become those shown in Figures IV.2 and IV.3 for typical 150 million barrel and 2-1/2 trillion cubic foot oil and gas fields, respectively. The rank ordering in terms of the costliness mentioned above changes by using different water depth and distance-to-shore for the different areas. The development of the "typical" field offshore California, in the case of oil, at a total cost of $156 million, is shown to be more expensive than that in the Gulf of Mexico, the Atlantic Coast, and the Lower Cook Inlet with total costs of $152 million, $135 million and $142 million, respectively. This is mainly because of much higher development drilling costs and higher offshore California as a result of the larger number of wells which are required, given the lower well productivity, to produce the reservoir and because of much higher platform costs as a result of deeper water.

In the case of gas (see Figure IV.3) the Atlantic and Gulf of Mexico are shown to be considerably more expensive than the Lower Cook Inlet, $1?9.7 million and $165.0 million versus $136.0 million, respectively; the Gulf of Alaska and the Bering Sea are shown as more expensive than the Beaufort Sea, $217.3 million and $215.9 million versus $211.8 million, respectively. In the case of the Atlantic Coast and the Gulf of Mexico, the higher expenditures are mainly caused by the higher pipeline costs since it is expected that fields in the Atlantic and in the Gulf of Mexico will require pipelines to shore averaging 75 miles compared to averages of 15 miles expected for the Lower Cook Inlet area. Longer pipelines to shore for the Bering Sea also results in higher costs for that area compared to the Beaufort Sea. The higher total field development costs for the Gulf of Alaska, compared with the Beaufort Sea, result from the expected deeper water of the Gulf of Alaska (400 feet versus 300 feet, respectively), which results in significantly higher total platform cost estimates.

The costs shown in Figures IV.2 and IV.3 must be regarded as *the minimum investment costs* required. Onshore terminals for oil include cost estimates for a tank farm but excludes potentially required processing facilities such as desalinization or desulfurlzation plants which depend on the quality of the crude. In the case of gas, onshore natural gas liquid processing facilities have also been excluded. The exploration costs, which are included in the total costs, include four exploration wells which can be considered to be the minimum exploration costs which would be allocated to a field.

Figures IV.4 and IV.5 show the relative contribution of the different cost categories to total exploration drilling and development costs calculated for the typical oil and gas fields for each major OCS area. It is clear from these two figures that the relative exploration drilling costs increase as one moves into more remote and more hostile areas.

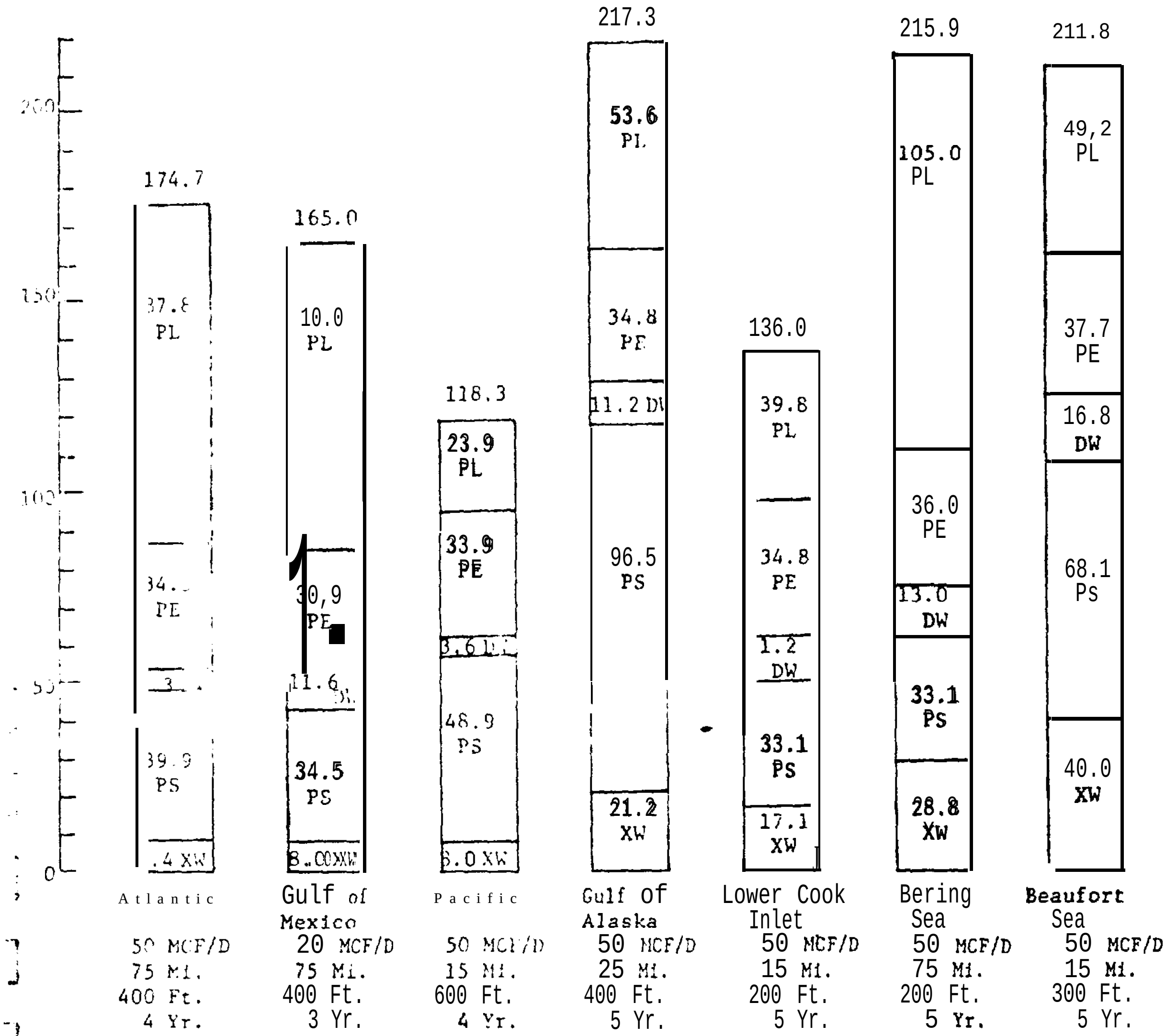


OT = Offshore Tankfarm
PL = Gathering Lines and Pipeline to Shore
PE = Platform Equipment

DW = Appraisal and Development Wells
PS = Platform Substructure
XW = Exploration Wells

FIGURE IV.2 Exploration Drilling Costs and Field Development Costs for a "Typical" Field with 150 Million Bbl Recoverable Reserves - Oil

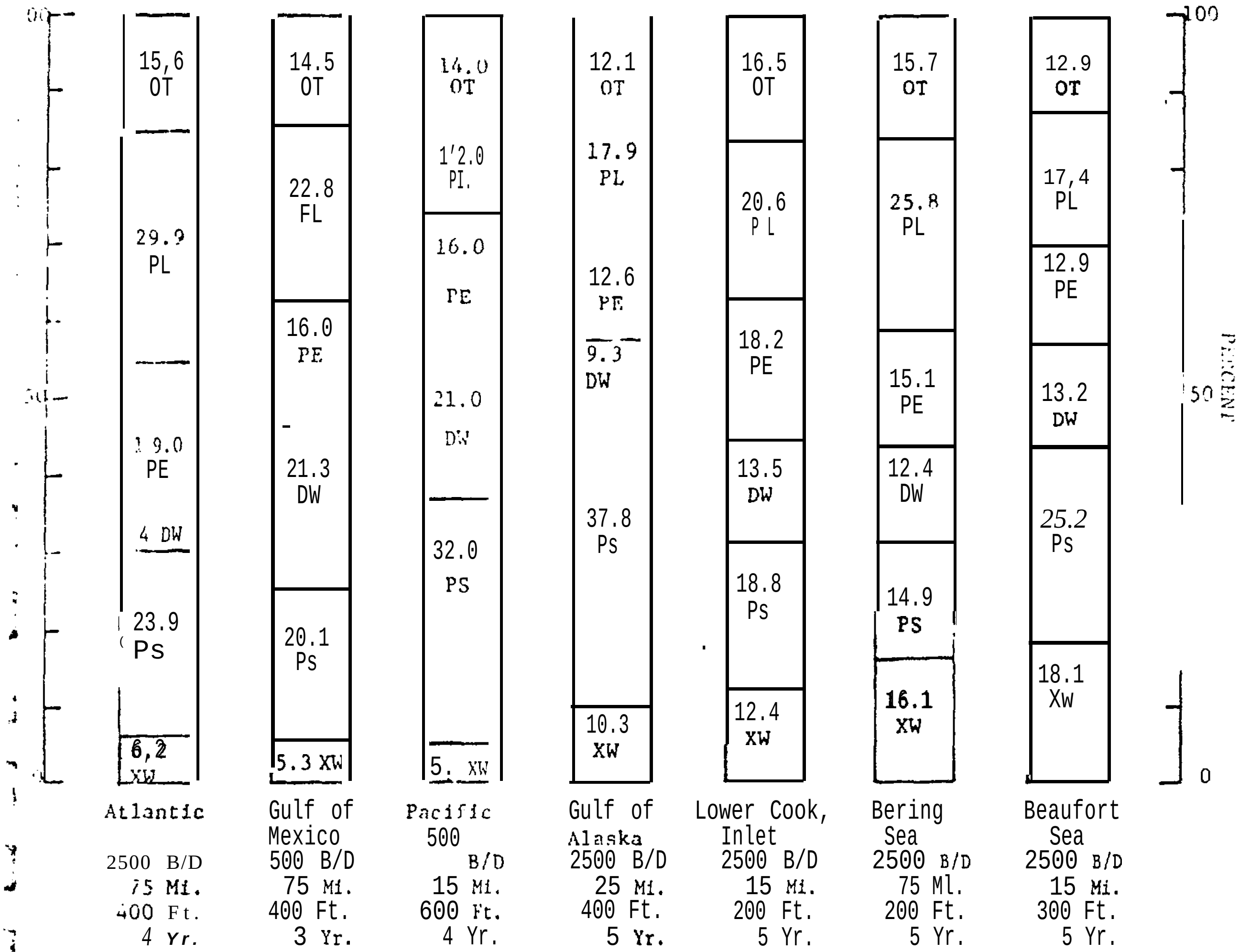
Source: Arthur D. Little, Inc., estimates.



PL = Gathering Lines and Pipeline to Shore
PE = Platform Equipment
DW = Development and Appraisal Wells
PS = Platform Substructure
Xw = Exploration Wells (4)

FIGURE IV.3 Exploration Drilling Costs and Field Development Costs for a "Typical" Field with 2500 Billion SCF Recoverable Reserves - Gas

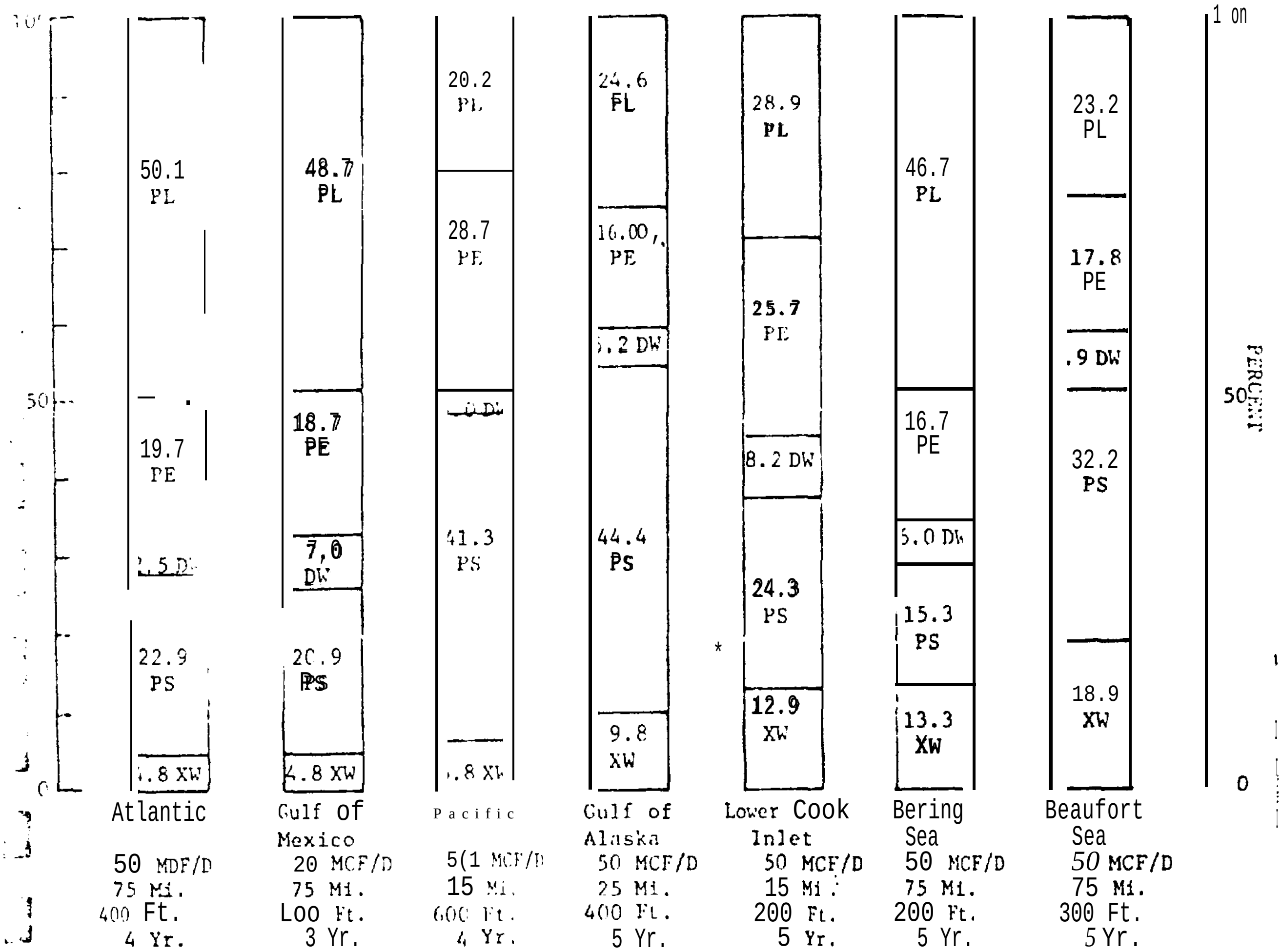
Source: Arthur D. Little, Inc., estimates



OT = Onshore Tankfarm
PL = Gathering Lines and Pipeline to Shore
PE = Platform Equipment
DW = Appraisal and Development Wells
PS = Platform Substructure
XW = Exploration Wells (4)

FIGURE IV.4 Percentage Distribution of Exploration Drilling Costs Field Development Costs for a "Typical" Field with 150 Million Bbl Recoverable Reserves - Oil

Source: Arthur D. Little, Inc., estimates.



PL = Gathering Lines and Pipeline to Shore
PE = Platform Equipment
DW = Development and Appraisal Wells
PS = Platform Substructure
XW = Exploration Wells (4)

FIGURE IV.5 Percentage Distribution of Exploration Drilling Costs and Field Development Costs for a "Typical" Field with 2500 Billion SCFT of Recoverable Reserves - Gas

Source: Arthur D. Little, Inc., estimates.

The costs of the typical four exploration wells are estimated to range from 5% to 7% of total costs in the areas off the Atlantic and Pacific Coasts and in the Gulf of Mexico, while their relative costs are estimated to range from 10% to 20% in the offshore areas of Alaska. In other words, not only are general cost levels higher in those remote and more hostile areas, but that portion of the total capital required for exploration and field development which has to be *risked* in exploration drilling is also higher. Companies can be expected to have to invest three-and-one-half times more capital in field exploration and field development in the Gulf of Alaska than in the Pacific, and they can be expected to have to risk at least four to five times as much capital in the exploration drilling phase. In addition, it will take about twice as long before they realize their first production.

Platform costs are extremely sensitive to water depth when comparing the Gulf of Mexico costs for 400 feet with costs for the Pacific, where an average water depth of 600 feet is expected. The platform costs as a portion of total investment range from 15% for an area with shallow waters and a relatively large investment in the pipeline to shore to 40% for a high cost area, such as the Gulf of Alaska with deep water (400 feet) and with relative closeness to the Coast (25 miles).

Development drilling costs in the cases shown ranged from 5% to 20% of total cost. These costs are sensitive to the average well productivity as illustrated by the difference between the development drilling costs for the Gulf of Mexico and for the Atlantic offshore areas, where they were estimated at $31.4 million and $7.3 million, respectively, for well productivities of 500 and 2500 b/d of oil.

Production equipment costs range from 12% to 20% of total costs in the case of oil and from 15% to 30% of total costs in the case of gas. For oil, costs for the pipeline to shore and the onshore tank farm range from 30% for the Pacific Coast and the Gulf of Alaska, which are close to shore, to 45% in the case of the Bering Sea and the Atlantic where it is expected that pipelines will be at least 75 miles long. For gas construction cost of the pipeline to shore requires by far the largest investment, requiring about 50% of total costs.

3. Unit Cost of Production: Economies of Scale

The costs for different fields in the same area and for the same fields between areas must also be compared in terms of dollars per unit of maximum field production capacity. Figures IV.6 and IV.7 show the unit costs by category for:

- The unit costs to drill four exploratory wells;
- The total of platform construction and installation costs, the production equipment costs and development drilling costs; and

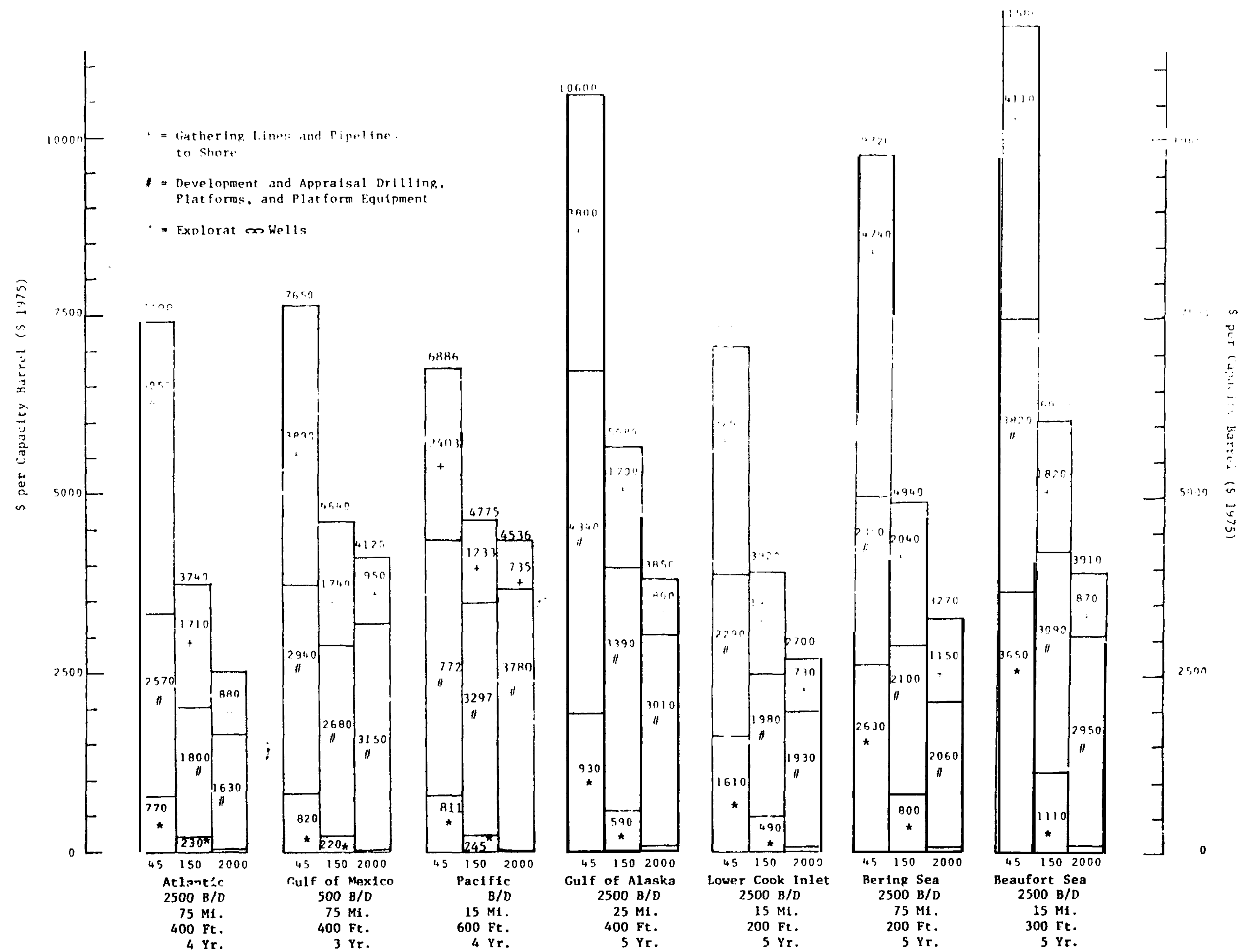


FIGURE IV.6 **Exploration and Field Development Costs per Bbl Production Capacity for Three Different Field Sizes - Oil**

Source: Arthur D. Little, Inc., estimates.

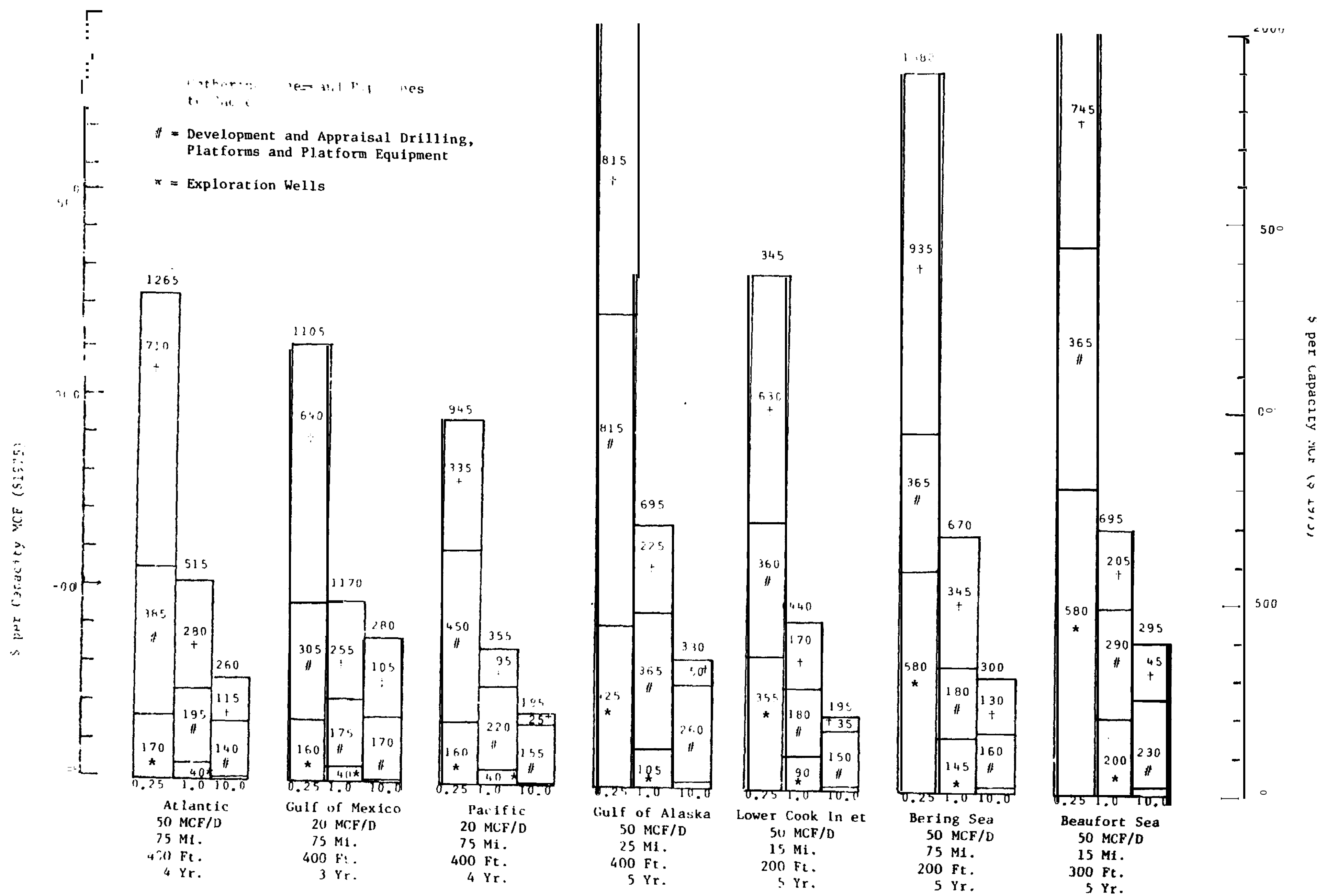


FIGURE IV.7 Exploration and Field Development Costs per SCFT Production Capacity for Three Different Field Sizes - Gas

So ce ar D. Little, Inc., estimates.

- The total costs for the pipeline to shore and, in the case of oil, the costs for an onshore tank farm.

These costs are shown for oil fields of 45 million barrels, 150 million barrels, and 2 billion barrels of recoverable reserves (Figure IV.6), and for gas fields of .25 trillion cubic feet, 1 trillion cubic feet and 10 trillion cubic feet of recoverable reserves (Figure IV.7), and for the average expected well productivity in each area.

Again, as in the case of the total cost estimates, it must be emphasized that the costs have been calculated for "typical" fields using expected values for water depth, distance-to-shore and average well productivity for the particular areas. If the expected values were the same for all areas, then the unit cost for the Beaufort Sea would be about five times higher than the unit cost shown for the Pacific Coast.

The geographical conditions assumed for the different sized fields in the same area were identical and the unit costs shown for these different field sizes are therefore comparable.

The economies of scale within the same area, when comparing a field of 45 million barrels with a field of 2 billion barrels, are shown to reduce the total costs per unit capacity by a factor of two for oil in the Gulf of Mexico and by a factor of three in the Beaufort Sea. The Gulf of Mexico shows a higher cost per unit capacity for the required construction and installation of the platforms, for the platform equipment and for development drilling when comparing the unit costs of the 2 billion barrel field with the unit costs of the 150 million barrel field. This is explained by the longer lead time required to drill all the development wells for the 2 billion barrel field, given the assumption of an average well productivity of 500 barrels per day, resulting in a longer producing life and a smaller required overall capacity than found to be necessary for the 2 billion barrel fields in the other OCS areas, where the average well productivity was assumed to be 2500 b/d and where, as a consequence, the smaller number of wells allows more rapid field development.

In the high cost areas like the Bering Sea and the Beaufort Sea, unitized exploratory drilling costs for the expected four exploratory wells per field are more than the total unit cost to explore for and develop a large field off the coast of the Atlantic and Pacific Coast.

Economies of scale are shown to be much more pronounced for gas fields than for oil fields. This is explained by the relatively larger investment required in the transportation system to shore for gas fields. In the Beaufort Sea, unit capacity costs are more than seven times higher for the smallest fields of .25 trillion cubic feet when compared to the largest field with recoverable reserves of 10 trillion cubic feet.

When comparing the unit capacity investment required for oil and gas on a BTU equivalent basis, assuming that one barrel of crude oil is equivalent to 6000 cubic feet of gas, it will be noticed that the unit investment costs for smaller gas fields are considerably higher than for oil fields with a comparable size, while unit capacity costs for the larger gas fields are considerably smaller than the unit capacity costs for the larger oil fields. Comparing estimates for the .25 trillion cubic feet field for gas with the 45 million barrel field for oil in the Beaufort Sea area, the gas field will require approximately $13,000 per barrel capacity, in terms of crude oil equivalent as compared with almost $12,000 per barrel capacity for the oil producing field. However, comparing the unit costs of a giant gas field of 10 trillion cubic feet of recoverable gas with the unit costs of a giant oil field of 2 billion barrels of recoverable oil, the investment costs per barrel of crude oil equivalent for the gas field are about $1,800 compared with the $4,000 per capacity barrel for the oil field.

4. Minimum Required Price

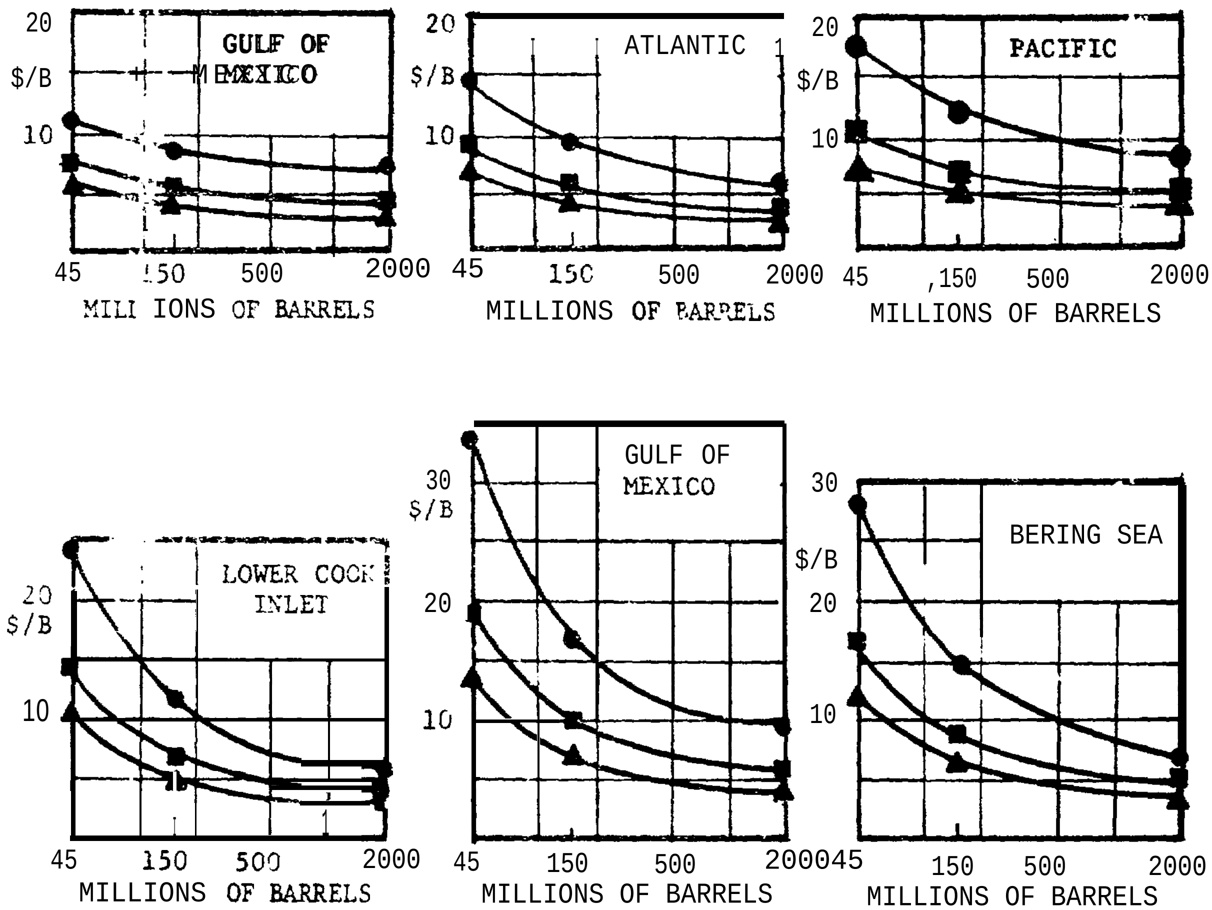
Given estimates for technical costs for each of the 17 different OCS areas and estimates for the time required to bring a discovered field into production, one can calculate the minimum price which a company must require in order to cover the costs for exploration, development and production of oil and gas fields of different sizes and under different conditions.

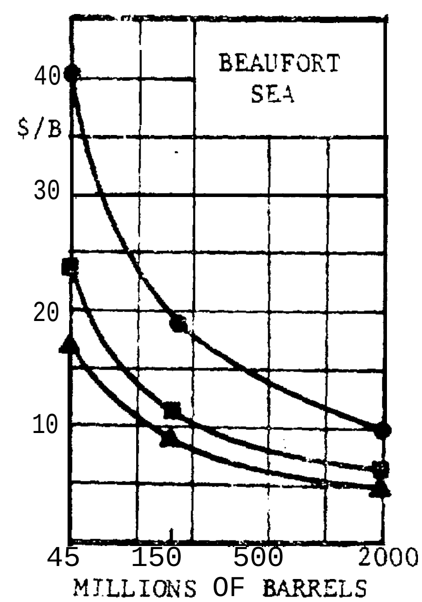
As explained in Chapter II, the Minimum Required Price resulted from a discounted cash flow calculation allowing for royalty and tax payments over the producing life of the fields. The price that is calculated can be considered to be the break-even price which allows companies to cover a nominal portion of the exploration costs plus the development and production costs while making a required return on their capital.

This rate of return on capital will vary depending on how a particular company assesses the riskiness of the particular area where it is trying to acquire the right to explore for oil and gas fields. It is beyond the scope of this report to try to show what this rate of return is or will be. We have therefore chosen to develop the Minimum Required Prices for different rates of return ranging from 10% per annum to 25% per annum.

Figures TV. 8 and IV. 9 show the Minimum Required Prices for oil and gas fields, respectively. As in the case with the per unit capacity costs, the Minimum Required Prices are shown for three different field sizes, 45 million barrels, 150 million barrels and 2 billion barrels in the case of oil and .25, 1 and 10 trillion cubic feet in the case of gas.

*6000 cubic feet of natural gas is roughly 1 barrel of crude oil equivalent on a thermal basis.





● 25% RATE OF RETURN

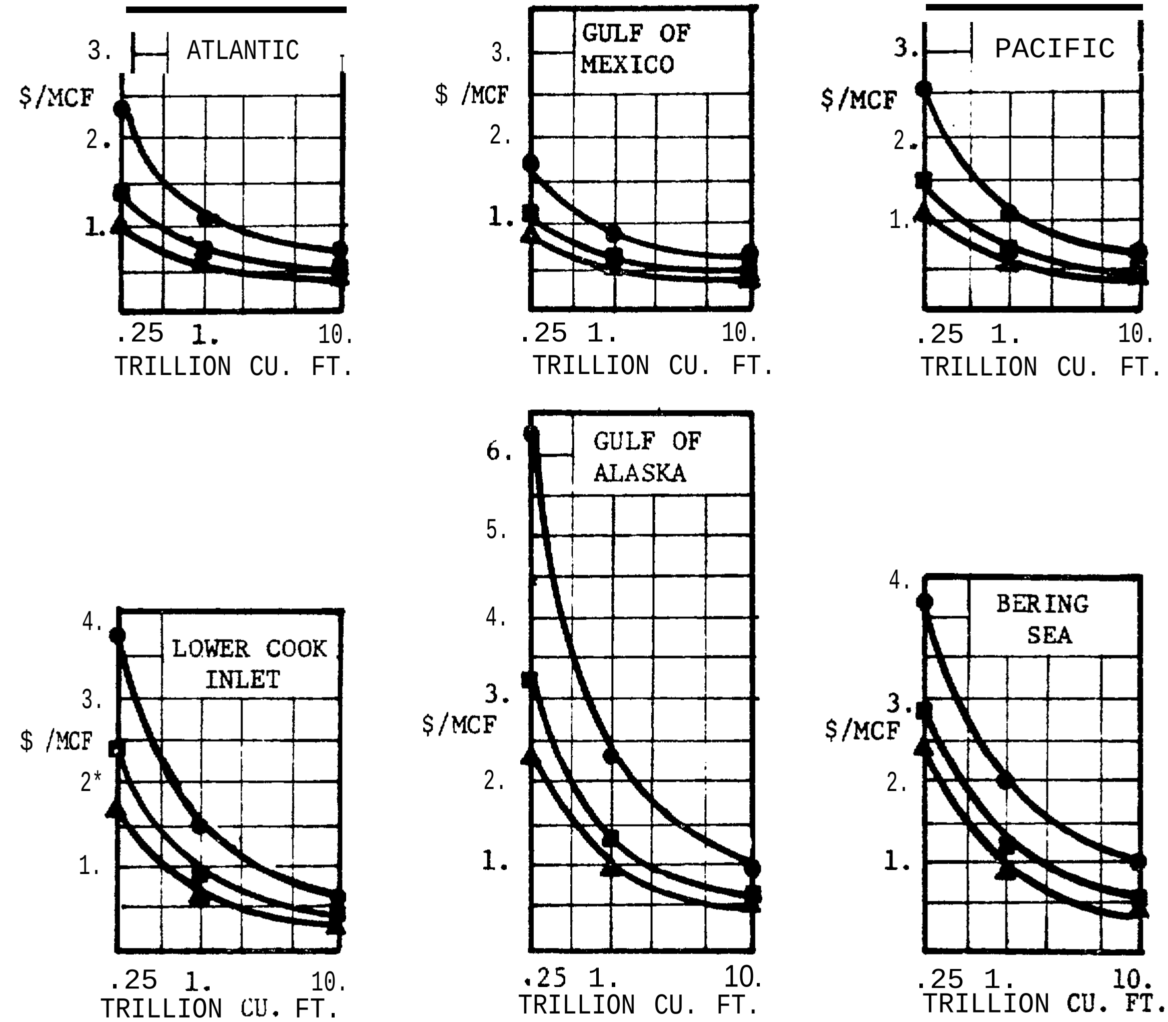
■ 15% RATE OF RETURN

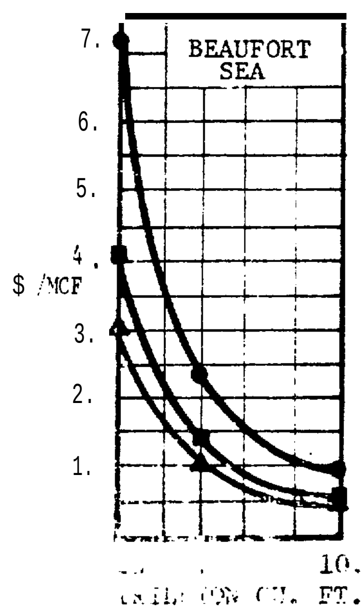
▲ 10% RATE OF RETURN

OIL

FIGURE IV.8 Minimum Required Prices as a Function of Field Size, Calculated with Different Rates of Return (for base case parameter values see Table IV-2)

Source: Arthur D. Little, Inc., estimates.





● 25% RATE OF RETURN

■ 15% RATE OF RETURN

A 10% RATE OF RETURN

GAS

FIGURE IV.9 Miminum Required Prices as a Function of Field Size with Different Rates of Return (1975 $) (for base case parameter values see Table IV-2)

Source: Arthur D. Little, Inc., estimates.

The shorter lead times between the first discovery and first production, as assumed for the Gulf of Mexico when compared with the Atlantic anti the Pacific Coast areas, are she-w, to result in a lower required price for the Gulf of Mexico both for the case of oil and gas.

The differences between Minimum Required Prices calculated for the same fit?.d with different rates of return are shown to be quite significant. A 45 million barrel field in the Lower Cook Inlet area would be economical with a Minimum Required Price of $10.63 if the company would be satisfied with a 10% rate of return. When requiring a 15% rate of return, however, the field would not be developed at a required price of $14.26 if the regulated price would be around the present level of $11.28. At a required *rate* of return of 25%, *even* a field of 150 million barrels might be considered not to be economical given a Minimum Required Price of $11.99.

For gas fields in the Lower Cook Inlet, assuming a regulated wellhead price of 52¢, even a giant field of 10 trillion cubic feet would not be economical when the required rate of return would be 25%, given a Minimum Required Price of 63¢ per MCF. However, with Minimum Required Prices of 3? and 41¢ per MCF in the case of required rates of return of 10% and 15%, respectively, the field would be economical. To illustrate the results, we show in Table IV-3 what the minimum economic field size would be in each of the seven areas which we considered for the three different required rates of return assumed if the wellhead price would be at 75¢ per MCF for gas and at $12 per barrel for oil. As shown, for gas, assuming a required rate of return of 15%, only fields larger than 500 billion cubic feet recoverable reserves would be developed in the Gulf of Mexico, a low cost area, and only fields larger than 4000 billion cubic feet would be developed in the Gulf of Alaska, a high cost area. For oil, again assuming a required rate of return of 15%, only fields larger than 17 million barrels recoverable reserves would be economical to develop in the Gulf of Mexico and only fields with more than 97 million barrels recoverable reserves in the Gulf of Alaska.

The minimum economic field size in the different areas shows to be very sensitive to the value of the required rate of return used in the calculations. In the case of gas, the minimum economic field size will be about eight times larger, 2500 billion cubic feet versus 310 cubic feet of recoverable reserves, if required rates of return are used which differ by a factor of 2.5, i.e., 25% versus 10%. In the case of oil, in the Gulf of Mexico the minimum economic field size would be 11 million barrels of recoverable reserves, assuming a required rate of return of 10%, and 47 million barrels, assuming a required rate of return of 25%, i.e., the minimum economic field size is larger by a factor of four if the required rate of return used to calculate this minimum economic field size is larger by a factor of 2.5.

The results of sensitivity tests, assuming different values of the different parameters and different development programs for the Gulf of Alaska area, are shown in Figures IV.10 and IV.11.

TABLE 3

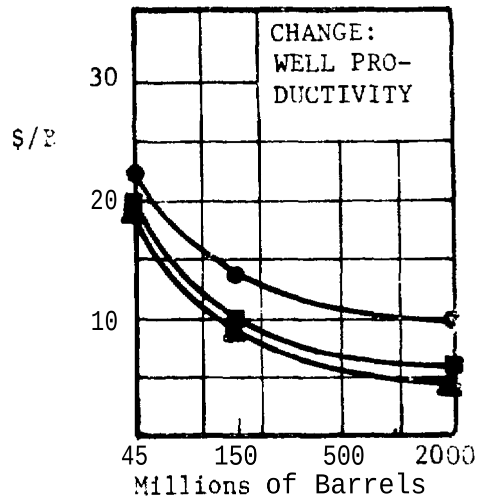
MINIMUM ECONOMIC FIELD SIZE[1]

Rate of Return	Gas (Billions of cu. ft.) Wellhead Price $.75/MCF 10%	15%	25%	Oil (Millions of Bbls) Wellhead Price $12.00/Bbl 10%	15%	25%	Assumptions: Average Well Prod. B/D/MCF/D	Distance to Shore	Water Depth	Years Delay[2]
Atlantic	180	290	660	17	26	70	2500/50	75	400	4
Gulf of Mexico	120	185	400	11	17	47	500/20	75	400	3
Pacific	220	300	770	19	37	125	500/50	15	600	4
Gulf of Alaska	660	1100	5400	60	97	425	2500/50	25	400	5
Lower Cook Inlet	370	560	1550	37	58	150	2500/50	15	200	5
Bering Sea	600	930	4400	49	80	260	2500/50	75	200	5
Beaufort Sea	850	1600	6400	80	135	560	2500/50	15	300	5

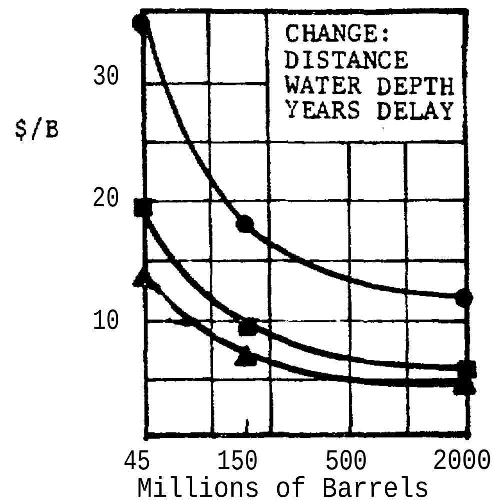
[1] In Recoverable Reserves.

[2] Number of years between first discovery well and first field production.

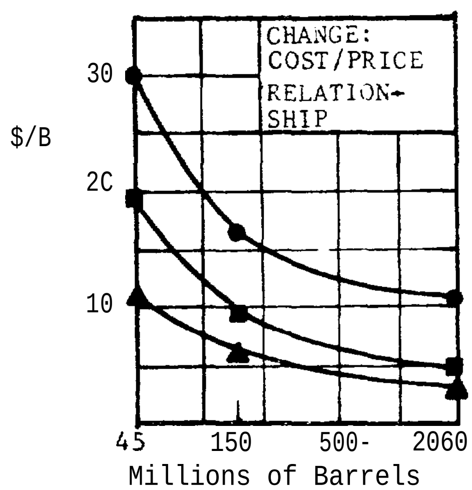
Source: Arthur D. Little, Inc., estimates.



- WELL PRODUCTIVITY 500 B/D
- WELL PRODUCTIVITY? 2500 B/D
- ▲ WELL PRODUCTIVITY 10000 B/D

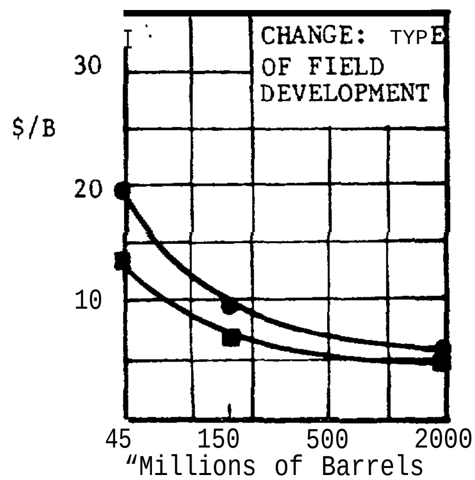


	WATER DEPTH FEET	DISTANCE MILES	DELAY YEARS
● HIGH	700	50	6
● BASE CASE	400	25	5
A LOW	200	5	4



- COSTS INCREASE AT 5%/YR. RELATIVE TO PRICES
- COSTS AND PRICES CHANGE AT THE SAME RATE (BASE CASE)

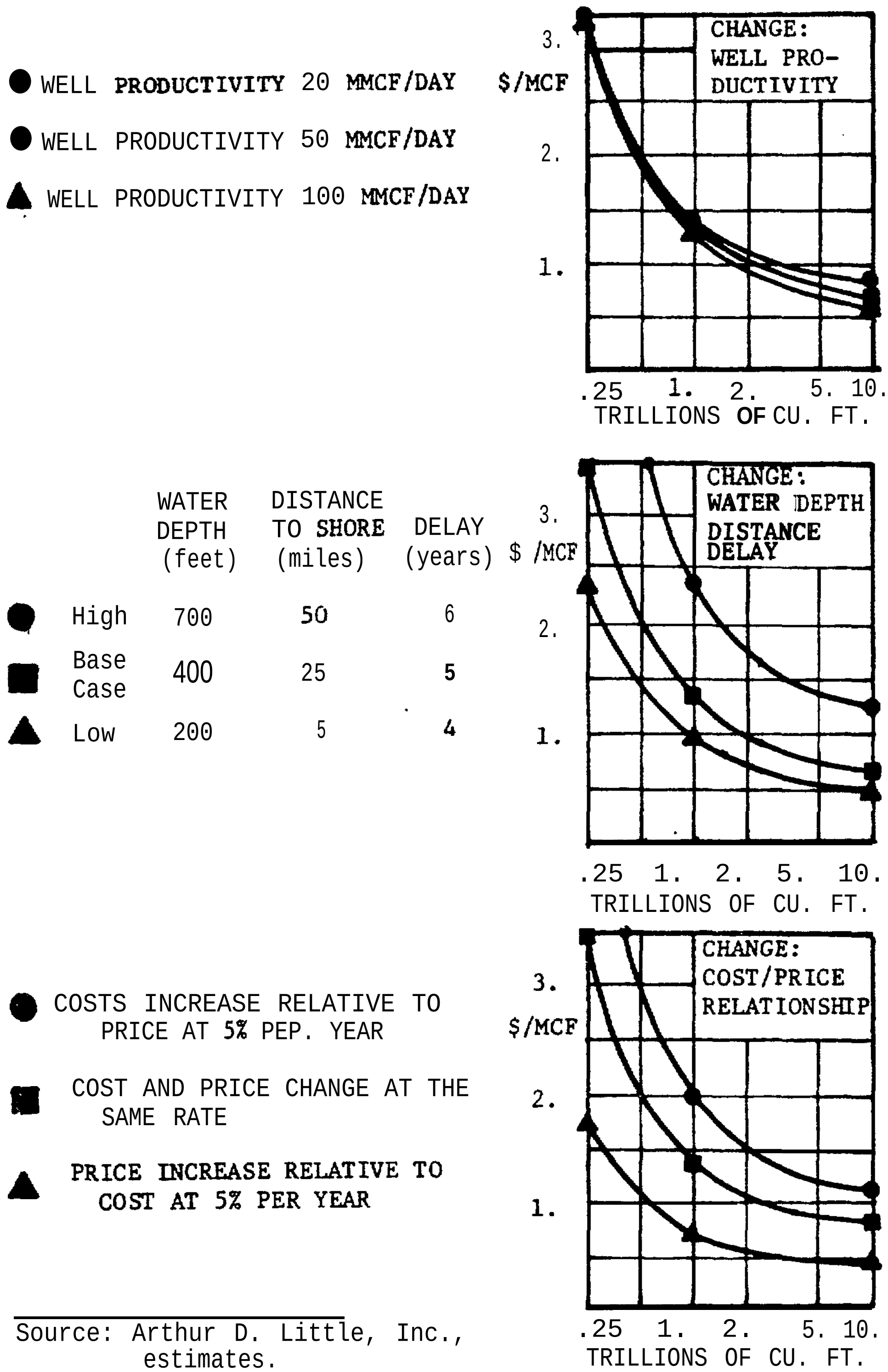
A PRICES INCREASE AT 5%/YR. RELATIVE TO COSTS



- FIXED PLATFORM IN FIELD DEVELOPMENT (BASE CASE)
- FLOATING PLATFORM/SUBSEA COMPLETION FIELD DEVELOPMENT

FIGURE IV.10 GULF OF ALASKA, OIL - Results of Sensitivity Tests on Minimum Required Prices (1975 $) (Base Case - see Table IV.2)

Source: Arthur D. Little, Inc., estimates.



Source: Arthur D. Little, Inc., estimates.

FIGURE IV.11 Results of Sensitivity Tests on Minimum Required Prices Using a Required Rate of Return of 15%/Yr. Base Case: Water Depth - 700 feet, Distance to Shore - 25 miles, Years Delay Till First Production 5 years

The sensitivity to changes in assumed well productivity is shown to be relatively small, especially for the smaller fields. For a 45 million barrel field, the Minimum Required Price for the Gulf of Alaska, given the assumptions on water depth and distance-to-shore and number of years delay until first production, would be $19.44 per barrel if a well productivity of 10,000 barrels per day was assumed and $22.99 per barrel if a 500 barrels per day well productivity was assumed. The Minimum Required Price for well productivities of 10,000 barrels per day and 500 barrels per day for a 2 billion barrel field would be $4.79 and $9.50, respectively; in other words, a well productivity of about 20 times as high would only reduce the Minimum Required Price by a factor of two.

The effect of assumed changes in cost price relationships are shown to be quite significant; assuming prices to increase relative to costs at 5% a year would reduce the Minimum Required Price from $5.67 to $3.75 per barrel for a 2 billion barrel field. Assuming costs to increase at 5% per year relative to prices over the life of the field would increase the minimum required price from $5.67 per barrel to $10.70 per barrel for the 2 billion barrel field.

Assuming a greater water depth, a larger distance to shore and a longer delay time between first discovery and first production also has a significant effect on the Minimum Required Prices. The effect of the different rates of return has already been discussed. Assuming different field development programs, using subsea completions and floating platform, has a significant effect on the smaller field sizes.

The sensitivity tests for gas fields show the" same results as obtained for oil (see Figure IV.11). Increasing the average well productivity five times from 20 MMCF/day to 100 MMCF/day decreases the minimum required price by only 30% from $0.56/MCF to $0.70/MCF in the case of the largest field size assumed (10 trillion cubic feet) and by less than 1% in the case of the smallest field assumed (250 billion cubic feet).

If prices will increase relative to costs at 5% per year, than the minimum required price decreases from $0.64/MCF to $0.37/MCF for the 10 trillion cubic feet field and from $3.45 to $1.74 for the 250 billion cubic feet field. If costs will increase relative to prices at a rate of 5% per year, than the Minimum Required Price will be $1.00/MCF for the 10 trillion cubic field and $4.37/MCF for the 250 billion cubic feet field.

The sensitivity to changes in assumed values for water depth, distance to shore and delay until first production is shown to be very significant. The Minimum Required Price almost doubles between the base case and high case.

B. PROJECTIONS OF FUTURE OIL AND GAS PRODUCTION

As described as part of the methodology (Chapter II), two types of information were used to simulate the exploration and subsequent development and production activities for different areas on the OCS for which lease sales have been proposed through 1978, i.e.:

- Probabilistic information on resource base size, structure size distribution and the distribution of possible fills of structures with oil or gas; and

- The information developed on the economics of exploration and development activities.

It should be emphasized that the projected production streams are functions of the proposed lease sale schedule which is shown in Table IV-4. It can be expected that if oil or gas is found in any of the areas which are considered in the analysis, the first lease sale will be followed by a second and maybe a third lease sale in the period covered by the analysis, i.e., 1975 to 1990. Therefore, it can be expected that for those areas where the possibility of substantial production levels is shown, these same production levels will not decline between 1985 to 1990 as shown in the projections but most probably will stay level or even increase.

1. Base Projections

Results of an area projection for the Gulf of Alaska, are shown in Table IV-5. The possible production of oil and gas and the possible annual expenditures required to find, develop and produce that oil and gas and to transport it to the nearest point of sale for ten benchmark years have been calculated for different price categories and at different levels of confidence within each price category. As shown in Table IV-5, , assuming a price of $4.50 per barrel for oil and $.75 per MCF for gas landed in California, no oil or gas will be developed even if there is some in the eastern part of the Gulf of Alaska. If the expected price for oil and gas landed in California is $7.50 per barrel and $1.25 per MCF, respectively, then, at a confidence level of 50%, one still cannot expect any oil or gas production to occur. Only at the lower confidence levels of 25% can one expect some oil production to result from an exploration and development effort in that area. At the 25% confidence level this production will reach its peak of at least 8 million barrels per year in 1985; at a 95% confidence level it will reach at least 360 barrels per year in 1985. As shown in Table IV-5, at a landed price in California of $1.25 per MCF, one cannot expect any gas to be developed and produced if found in the Gulf of Alaska. Only if the expected price for gas landed in California is close to $2.00

TABLE IV-4

LEASE SALE SCHEDULE AND
MILLIONS OF ACRES LEASED AS ASSUMED
FOR AREA SIMULATIONS

	Area Name	Years of Lease Sale and Millions of Acres Leased				
		1974	1975	1976	1977	1978
1.	North Atlantic			< 0.4 >		
2.	Mid Atlantic			< 0.4 >		
3.	South Atlantic			< 0.4 >		
4.	Eastern Gulf	< 0.5 >				
5.	Central & Western Gulf	1.2 >	< 1.2 >			
6.	South California and Santa Barbara Channel			<	0.6	>
7.	Northern California and Washington Oregon					
8.	Gulf of Alaska, East			< 0.4 >		
9.	Gulf of Alaska, Kodiak				< 0.4 >	
10.	Gulf of Alaska, Aleutian Shelf					< 0.3 >
11.	Lower Cook Inlet				< 0.5 >	
12.	Outer Bristol Basin					< 0.5 >
13.	Bering Sea, Norton Basin				< 0.5 >	
14.	Bering Sea, St. George				< 0.5 >	
15.	Chukchi Sea, Hope Basin					< 0.5 >
16.	Beaufort Sea				< 0.5 >	

Source: Arthur D. Little, Inc., estimates.

OIL PRODUCTION: IN MMB PER YEAR

Expected Price 4.50 $/BL or .75 $/MCF
(No Production)

Expected Price 7.50 $/BL or 1.25 $/MCF

	Milestone Years					
Confidence Level	1980	1981	1982	1983	1985	1990
5%	.00	127.17	194.57	265.42	359.28	258.02
25%	.00	.00	.00	60.07	80.88	60.38
50%	.00	.00	.00	.00	.00	.00
75%	.00	.00	.30	.00	.00	.00
95%	.00	.00	.00	.00	.00	.00

Expected Price 12.00 $/BL or 2.00 $/MCF

	Milestone Years					
Confidence Level	1980	1981	1982	1983	1985	1990
5%	.00	127.17	194.57	265.42	381.72	284.56
25%	.00	.00	52.53	76.46	102.80	71.56
50%	.10	.00	.00	18.40	35.34	26.34
75%	.00	.00	.00	.00	.00	.00
95%	.00	.90	.1-10	.00	.00	.00

Expected Price 18.00 $/BL or 3.00 $/MCF

	Milestone Years					
Confidence Level	1980	1981	1982	1983	1985	1990
5%	.00	127.17	194.57	265.42	391.72	284.56
25%	.00	.00	52.53	76.46	102.80	73.54
50%	.00	.90	.00	18.86	35.39	26.67
75%	.00	.00	.00	.00	.00	.00
95%	.00	.00	.00	.00	.00	.00

Expected Price 24.00 $/BL or 4.00 $/MCF

	Milestone Years					
Confidence Level	1980	1981	1982	1983	1985	1990
5%	.00	127.17	194.57	265.42	391.72	284.56
25%	.00	.00	52.53	78.56	102.80	73.54
50%	.00	.00	.00	22.39	35.78	27.17
75%	.00	.00	.00	.00	.00	.00
95%	.00	.00	.00	.00	.00	.00

GAS PRODUCTION: IN MMCF PER YEAR

Expected Price 4.50 $/BL or .75 $/MCF
(No Production)

Expected Price 7.50 $/BL or 1.25 $/MCF
(No Production)

Expected Price 12.00 $/BL or 2.00 $/MCF

	Milestone Years					
Confidence Level	1980	1981	1982	1983	1985	1990
5%	.00	209.01	313.76	508.64	522.42	522.42
25%	.00	.00	.00	.00	.00	.00
50%	.00	.00	.00	.00	.00	.00
75%	.00	.00	.00	.00	.00	.00
95%	.00	.00	.00	.00	.00	.00

Expected Price 18.00 $/BL or 3.00 $/MCF

	Milestone Years					
Confidence Level	1980	1981	1982	1983	1985	1990
5%	.00	209.01	337.80	508.64	633.80	633.80
25%	.00	.00	.00	102.12	131.74	131.74
50%	.00	.00	.00	.00	38.79	38.79
75%	.00	.00	.00	.00	.00	.00
95%	.00	.00	.00	.00	.00	.00

Expected Price 24.00 $/BL or 4.00 $/MCF

	Milestone Years					
Confidence Level	1980	1981	1982	1983	1985	1990
5%	.00	209.01	337.80	508.64	646.39	646.39
25%	.00	.00	.00	102.12	154.30	154.30
50%	.00	.00	.00	.00	47.93	47.93
75%	.00	.00	.00	.00	.00	.00
95%	.00	.00	.00	.00	.00	.00

TABLE IV.5 Projections of Oil and Gas Production Levels Under Different Price Scenarios and at Different Levels of Confidence as Resulting from Lease Sales Through 1978 - Gulf of Alaska, East per MCF can one expect production on the Gulf of Alaska areas to accrue at a 5% confidence level at a peak of at most 522 billion cubic feet per year in 1985. At an expected price of $3.00 per MCF production levels in the eastern part of the Gulf of Alaska would accrue in 1985 at levels of at most 739 billion cubic feet per year, at a confidence level of 50%, at most 132 billion cubic feet per year at a confidence level of 25% and 634 billion cubic feet per year at a confidence level of 5%.

The prices shown in Table IV-5 are Minimum Required prices to cover the nominal amount of exploration drilling costs, i.e., the cost for drilling four exploratory wells, all development and production costs, plus the charges for the transportation of the crude oil and gas to the closest market, which has been assumed to be California. Lease bonuses are excluded. For the same level of confidence, more production can be expected if the expected prices are higher; more previously marginal fields are developed and produced as the price increases. It should be emphasized that the incremental amount of production shown to result from a higher expected price level cannot be interpreted as showing the price sensitivity of production in a particular area. It only shows the incremental production which can be expected to result from a successful exploration effort during the first exploration period (after the first lease sale) if the industry is confident that future prices will be at the higher level instead of at the lower level. It is assumed that companies will not develop any structures or structural traps unless they hold "commercial" reserves, i.e., promise to contain at least the millions of barrels of recoverable oil or trillions of cubic feet of recoverable gas necessary to pay for development and production costs plus a nominal amount of exploration costs. Hence, the lease sale process is assumed to be efficient in selecting the bigger structures which have a higher chance of containing a large oil or gas field and leaving out most of the smaller structures which would only be economic at the highest price levels shown in Figure IV.11.

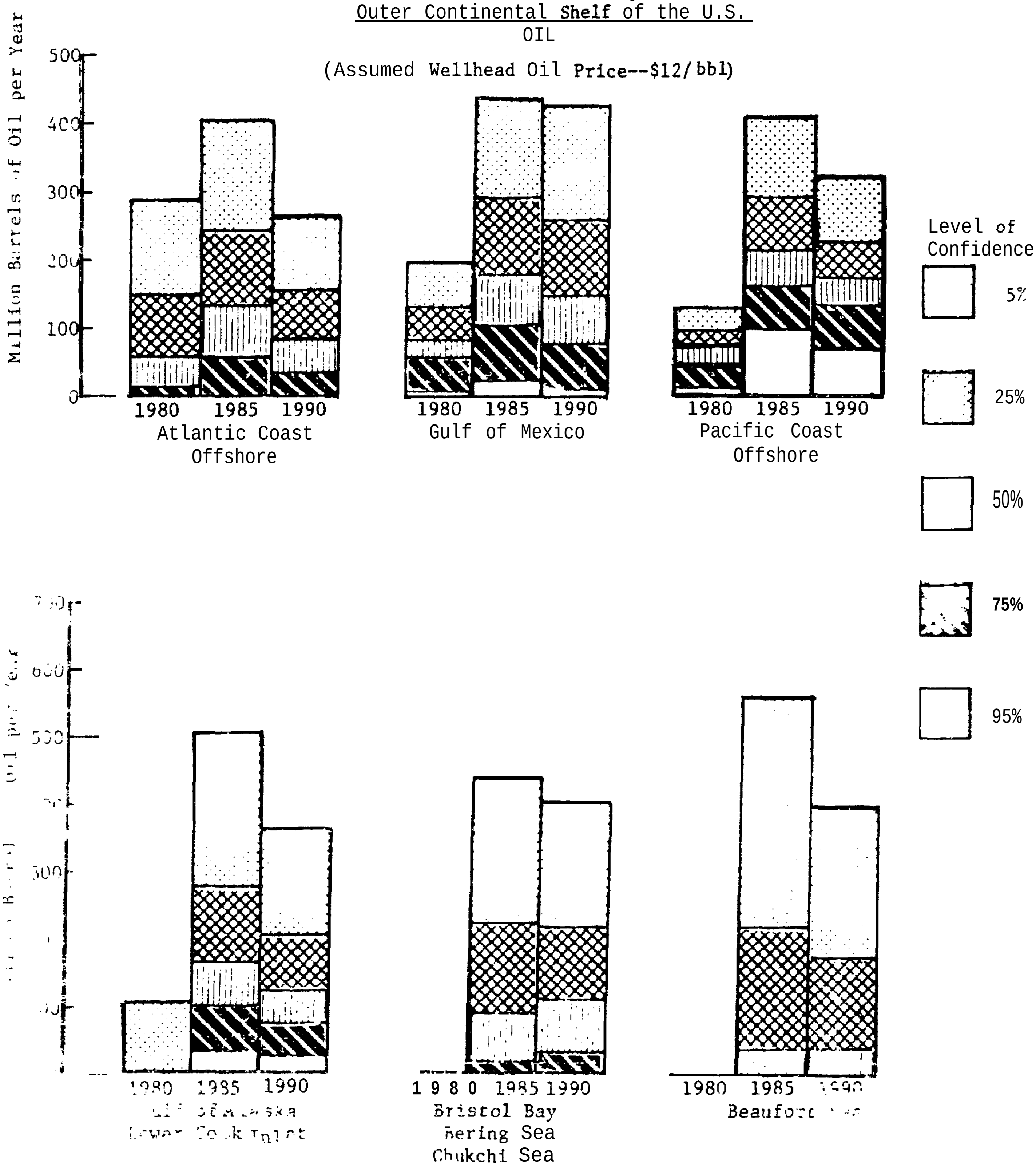
The results of the probabilistic production projections for the 16 different lease sales assumed to be held through 1978 (see Table IV-4) combined to obtain production projections at different confidence levels for the different areas off the Coast of the U.S. and for the benchmark years 1980, 1985 and 1990. For each benchmark year, the probabilistic forecasts are combined to obtain the joint probability distributions of total possible production levels for consolidated areas of the Atlantic Coast, the Gulf of Mexico, the Pacific Coast, or Alaska offshore. Figures IV.12 and IV.13 show the results when probabilistic projections are combined for oil and gas production for the different combined areas. The expected price levels assumed for these aggregated probabilistic forecasts were $12.00 per barrel for oil for all areas and $1.25 per MCF for gas, respectively, off the Atlantic Coast, in the Gulf of Mexico and off the Pacific Coast, and $2,00 per MCF for gas produced and transported to California from Alaskan offshore areas. In other words, Figures IV.12, IV.13, IV.14 & IV.15 show for combined areas the expected total production levels resulting, at different levels of confidence, from lease sales through 1978 when

FIGURE IV. 12

Estimates of Possible Annual Production Levels At Different Confidence Levels from Areas Leased or to be Leased Through 1978 on the Outer Continental Shelf of the U.S.

OIL

(Assumed Wellhead Oil Price--$12/bbl)



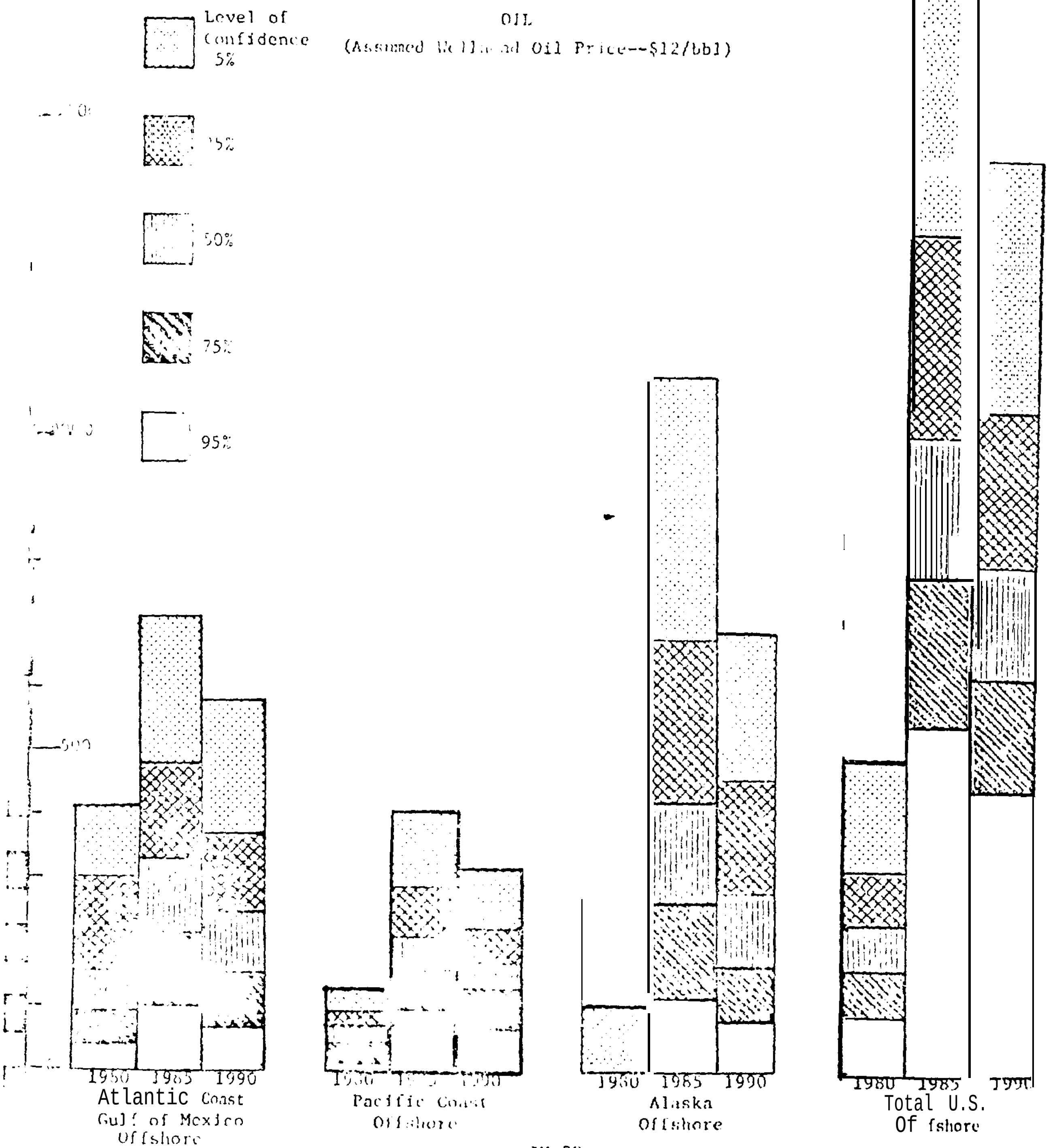
Arthur D. Little, Inc., estimates,

FIGURE IV.13

Estimates of Possible Annual Production Levels At Different Confidence Levels for Areas Leased or to be Leased Through 1978 on the Outer Continental Shelf of the U.S.

OIL

(Assumed Wellhead Oil Price--$12/bbl)



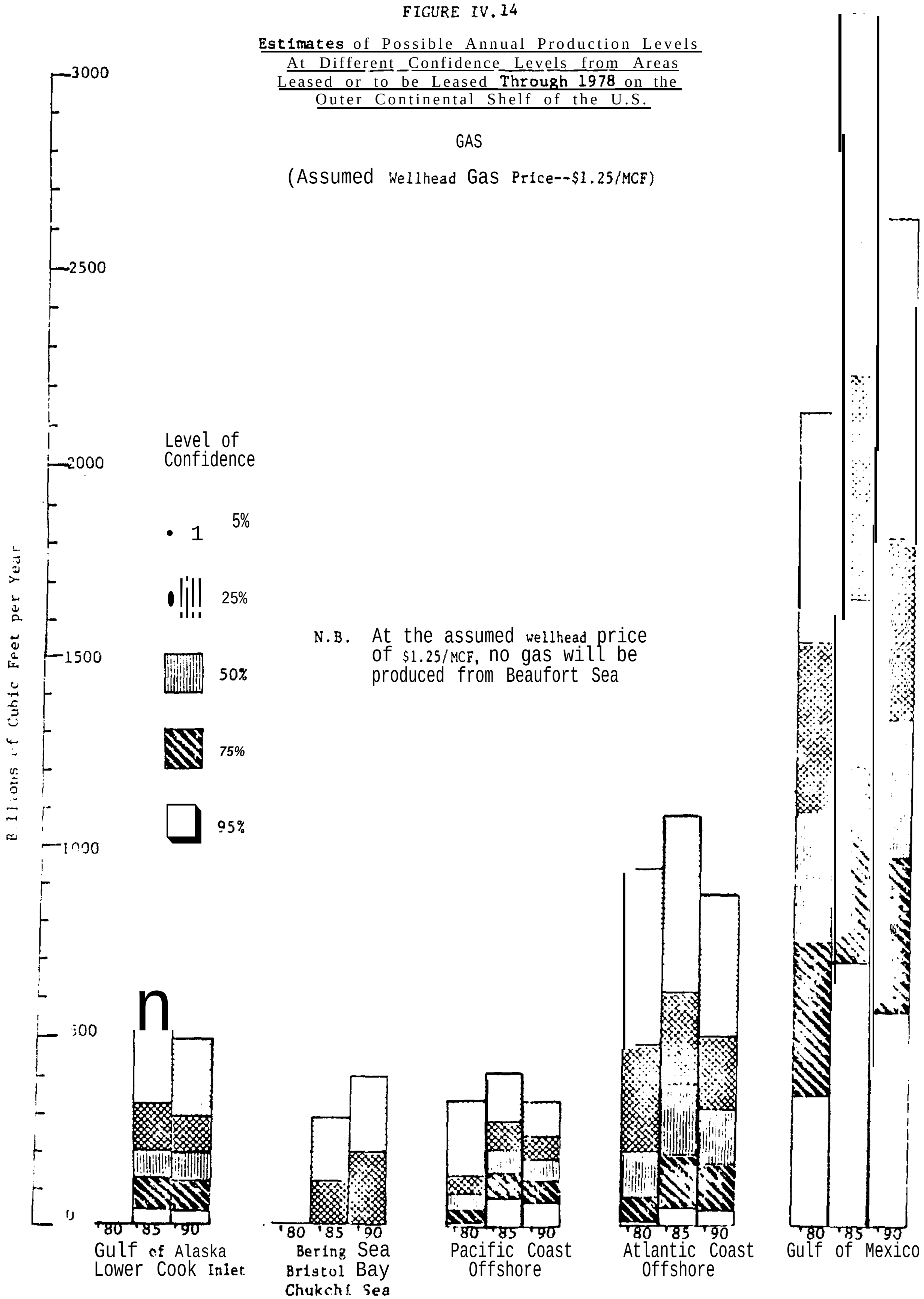
Source: Arthur D. Little, Inc., estimates.

FIGURE IV.14

Estimates of Possible Annual Production Levels At Different Confidence Levels from Areas Leased or to be Leased Through 1978 on the Outer Continental Shelf of the U.S.

GAS

(Assumed Wellhead Gas Price--$1.25/MCF)



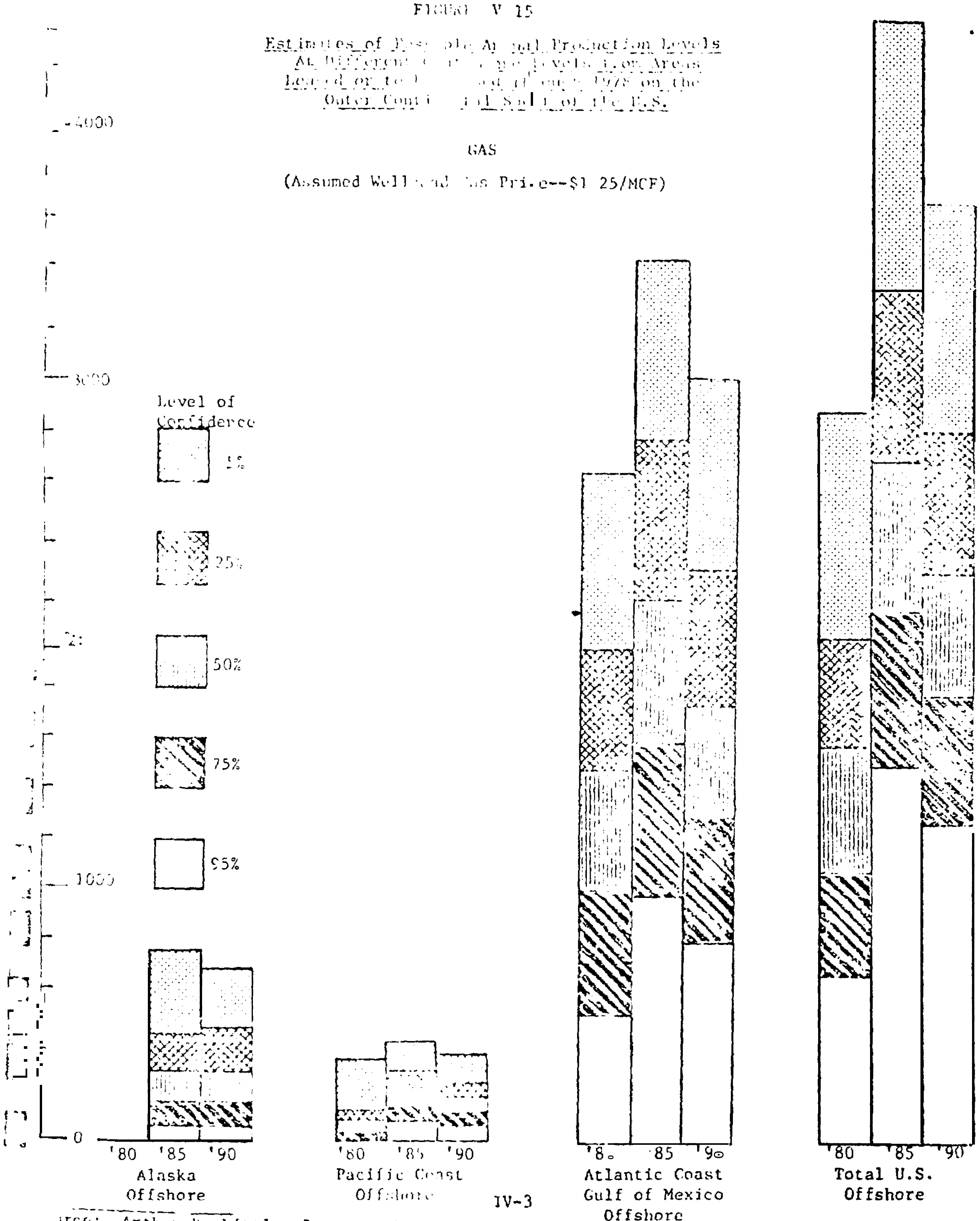
Source: Arthur D. Little, inc., estimates.

FIGURE V 15

Estimates of Possible Annual Production Levels At Different Confidence Levels from Areas Leased or to be Leased through 1978 on the Outer Continental Shelf of the U.S.

GAS

(Assumed Wellhead Gas Price—$1 25/MCF)



Source: Arthur D. Little, Inc., estimates.

wellhead prices for oil ranges between $11.00 and $12.00 per barrel and when the wellhead price for gas is approximately $1.25 per MCF. It is apparent from these figures that when the possible futures are reduced by considering the projections from an accelerated lease sale through 1978, then the full range of all possible outcomes in terms of potential oil production in 1985 reaches from a total of at most 57o million barrels per year (1.6 million barrels per day) at a high level of confidence (95%) to a high of at most 1840 million barrels per year (5.1 million barrels per day) at low levels of confidence (5%) if well-head prices are expected to be approximately $12 per barrel. Potential production of gas for all areas combined in 1985 ranges from at most 1500 billion cubic feet per year (4.11 billion cubic feet per day) at a high level of confidence (95%) to a high of at most 4500 billion cubic per year (12.3 billion cubic feet per day) at a low level of confidence (5%) .

2. Expected Production Under Alternate Scenarios

The expected values of the projected production level for oil and gas resulting from projections for the individual areas for a range of different price levels, $4.50 per barrel to $18.00 per barrel for oil and $.75 per MCF to $3.00 per MCF for gas, are shown in Tables IV-6 and IV-7. The expected values shown are the arithmetic mean of the corresponding probability distributions which result from the Monte Carlo simulation. As such, they can be combined for the different areas to provide the expected levels of total production for different combined areas. (The required prices are relative to the landed costs of the crude oil and natural gas, implying that transportation charges to the market area are included in the costs.)

The relationship between higher expected price levels and incremental production does not represent the price sensitivity of oil and gas production for the overall areas. It only indicates the increased production which can be expected for a particular set of assumptions on size of resource base, field size distribution, and timing and size of the different lease sales if the industry is convinced that the price levels of the landed crude and the landed gas at the points of reference will indeed materialize at the different levels shown after having taken into account the factors which impact on these prices such as the regulatory climate and energy supply and demand conditions.

In 1985 expected crude oil production from OCS areas is expected to range from 234 million barrels per year or 0.64 million barrels per day under a Price scenario of $4.50 per barrel to 1038 million barrels per year or 2.84 million barrels per day under a price scenario of $18.00 per barrel. Expected gas production levels in 1985 will range from 1760 billion cubic feet per year or 4.82 billion cubic feet per day assuming a $.75 per MCF price to 2363 billion cubic feet per year or 8.12 billion cubic feet [illegible] assuming a $3.0 ! per MCF price.

TABLE IV-6

EXPECTED PRODUCTION LEVELS FOR CRUDE OIL
IN BENCHMARK YEARS FROM SELECTED
OCS AREAS LEASED OR TO BE
LEASED THROUGH 1978

Oil MMBL/Year

	Landed Price[1]											
	$4.50/Bbl			$7.50/Bbl			$12.00/Bbl			$18.00/Bbl		
	1980	1985	1990	1980	1985	1990	1980	1985	1990	1980	1985	1990
N. Atlantic	19.13	29.30	18.91	25.14	42.44	27.50	25.92	43.80	78.38	25.93	43.94	28.48
Mid Atlantic	33.21	56.77	36.78	44.30	76.72	49.82	44.96	77.99	50.61	45.01	78.12	50.70
S. Atlantic	2.72	6.69	4.38	8.95	21.72	14.29	9.53	23.24	15.29	9.55	23.35	15.37
Total	55.06	[illegible].76	60.07	78.39	140.93	91.61	80.41	145.02	94.28	80.49	145.42	94.55
Gulf of Mexico												
E. Gulf MALFA	15.25	27.84	22.55	45.50	55.93	40.70	45.68	56.09	40.80	45.69	56.09	40.80
Cent. & west Gulf	19.10	70.53	76.76	44.98	140.69	128.87	45.08	141.22	129.32	45.09	141.24	129.33
Total	34.35	98.38	99.31	90.47	196.62	169.57	90.76	197.[illegible]2	170.11	90.77	197.34	170.13
Pacific OCS												
S. California	1.00	2.60	3.71	>6.0	154.70	134.00	59.40	165.37	141.90	59.60	166.40	142.62
Washing./Oregon	1.87	23.35	16.05	3.09	51.18	35.69	3.26	54.59	38.07	3.26	54.88	38.27
Total	2.87	25.95	19.76	59.09	205.88	169.69	62.66	219.96	179.97	62.86	221.28	180.89
Alaska OCS												
GOA East	--	--	--	--	56.34	40.76	--	75.17	54.89	--	76.30	55.76
GOA Kodiak	--	--	--	--	14.04	11.16	--	23.74	18.89	--	24.85	19.80
GOA S. Aleutian	--	--	--	--	--	--	--	.37	1.35	--	.71	2.25
Lower Cook Inlet	2.69	16.68	11.50	7.50	87.40	61.65	7.50	95.30	67.41	7.50	96.33	68.17
Bristol Basin	--	--	--	--	31.24	43.97	--	33.12	47.83	--	33.18	47.92
Bering Sea-Norton	--	--	--	--	18.84	23.79	--	28.51	34.54	--	29.02	35.08
Bering-St. George	--	--	--	--	53.64	42.09	--	66.03	52.59	--	67.03	53.43
Chukchi Sea	--	--	--	--	1.31	1.14	--	1.31	5.60	--	1.31	5.86
Beaufort Sea	--	--	--	--	105.73	84.35	--	141.83	112.96	--	144.79	115.69
Total	2.69	16.68	11.50	7.50	368.54	308.90	7.50	465.39	396.06	7.50	473.52	403.96
Grand Total	94.97	233.77	190.64	235.45	911.97	739.77	241.33	1027.69	840.42	[illegible]41.62	1037.56	849.53
MMBL/Day	.26	0.64	0.52	.65	2.50	2.03	.66	2.82	2.30	.66	2.84	2.33

Source: Arthur D. Little, Inc., estimates.

[1] For Alaskan areas crude oil is assumed to be landed in California.

TABLE IV-7

EXPECTED PRODUCTION LEVELS FOR
NONASSOCIATED GAS IN BENCHMARK YEARS
FROM SELECTED OCS AREAS LEASED OR
TO BE LEASED THROUGH 1978

Gas BCF/Year	Landed Price[1]											
	$.75/MCF			$1.25/MCF			$2.00/MCF			$3.00/MCF		
	1980	1985	1990	1980	1985	1990	1980	1985	1990	1980	1985	1990
N. Atlantic	55.09	88.95	74.58	84.13	140.48	118.51	89.00	151.89	128.48	89.28	152.27	128.80
Mid Atlantic	106.38	133.25	106.93	124.30	171.98	140.47	130.23	185.24	151.98	130.33	185.72	152.40
S. Atlantic	--	--	--	11.92	27.14	24.13	16.21	34.70	30.69	16.30	34.88	30.84
Total	161.47	222.20	181.51	220.35	339.60	283.10	253.44	371.83	311.16	235.91	372.87	312.04
Gulf of Mexico												
E. Gulf MAFLA	14.49	14.49	9.73	40.99	41.18	27.41	44.03	44.21	29.34	44.03	44.21	29.34
Cent & West Gulf	939.96	1413.01	1140.48	1067.94	1650.72	1343.01	1078.77	1671.83	1361.15	1078.77	1671.83	1361.15
Total	954.44	1427.50	1150.21	1108.93	1691.90	1370.42	1122.80	1716.05	1390.49	1122.80	1716.05	1390.49
Pacific OCS												
S. California	66.74	88.56	69.23	90.25	131.99	106.17	95.76	143.38	116.11	96.72	146.04	118.46
Washing./Oreg.	2.86	22.68	21.15	2.86	47.65	45.15	3.75	58.90	55.78	3.87	61.24	58.02
Total	69.60	111.24	90.38	93.11	179.65	151.32	99.50	202.28	171.89	100.58	207.28	176.48
Alaska OCS												
GOA East	--	--	--	--	--	--	--	73.56	71.97	--	112.57	110.98
GOA Kodiak	--	--	--				--	13.30	13.30	--	22.63	23.59
GOA S. Aleutian	--	--	--	--	--	--	--	--	--	--	.42	3.33
Lower Cook Inlet	--	--	--	--	--	--	3.91	112.74	108.84	3.91	126.95	122.85
Bristol Basin	--	--	--	--	--	--	--	54.51	83.51	--	65.17	100.09
Bering Sea-Norton	--	--	--	--	--	--	--	--	--	--	19.38	23.38
Bering-St. George	--	--	--	--	--	--	--	--	--	--	111.64	115.81
Chukchi	--	--	--	--	--	--	--	--	--	--	6.32	26.09
Beaufort Sea	--	--	--	--	--	--	--	--	--	--	200.94	201.05
Total	--	--	--	--	--	--	3.91	254.11	277.62	3.91	666.61	727.16
Total	1185.51	1760.93	1422.09	1422.39	2211.14	1804.84	1461.65	2544.26	2151.16	1463.20	2962.80	2606.18
/Day	3.25	4.82	3.90	3.90	6.06	4.95	4.01	6.97	5.89	4.01	8.12	7.14

[1] Alaskan areas gas is assumed to be landed in California.

Source: Arthur D. Little, Inc., estimates.

3. Production From Onshore and Existing Offshore Areas

To assess the potential impact of expected production from new OCS areas, a forecast was required, by state, of future potential production from on.here areas and existing offshore areas. These projections of production were made as follows:

- Mean values for estimated undiscovered recoverable resources for 75 petroleum provinces as obtained from the USGS were assigned to the individual states;
- Remaining Revisions and Extensions were calculated as follows:

  USGS Total Resources

  - USGS Cumulative Production
  - USGS undiscovered Resources
  - API Reserves (d.d. December 31, 1974)

  = Revisions and Extensions to Proven Reserves

- A high and low projection of total production was made by projecting separately:
  - Production from existing reserves derived by declining 1974 production levels for the individual states at 10% per annum;
  - Production from revisions and extensions to reserves existing in 1974, using the national availability profile to obtain the production profile for extensions and revisions realized in any given year;
  - Production from newly discovered reserves assuming an optimistic and a pessimistic discovery scenario; and,
  - Production from extensions and revisions to newly discovered reserves.

An optimistic production forecast was obtained assuming that economic incentives would result in an increase in discovery rates relative to 1974 levels (see Figure Iv-16). Under that scenario half (50%) of the undiscovered resources were assumed to be discovered within the next 25 years, and all of the undiscovered resources were assumed to be discovered in the next 50 years. The future production levels for Alaska onshore (Prudhoe Bay) were prespecified. Projections of production

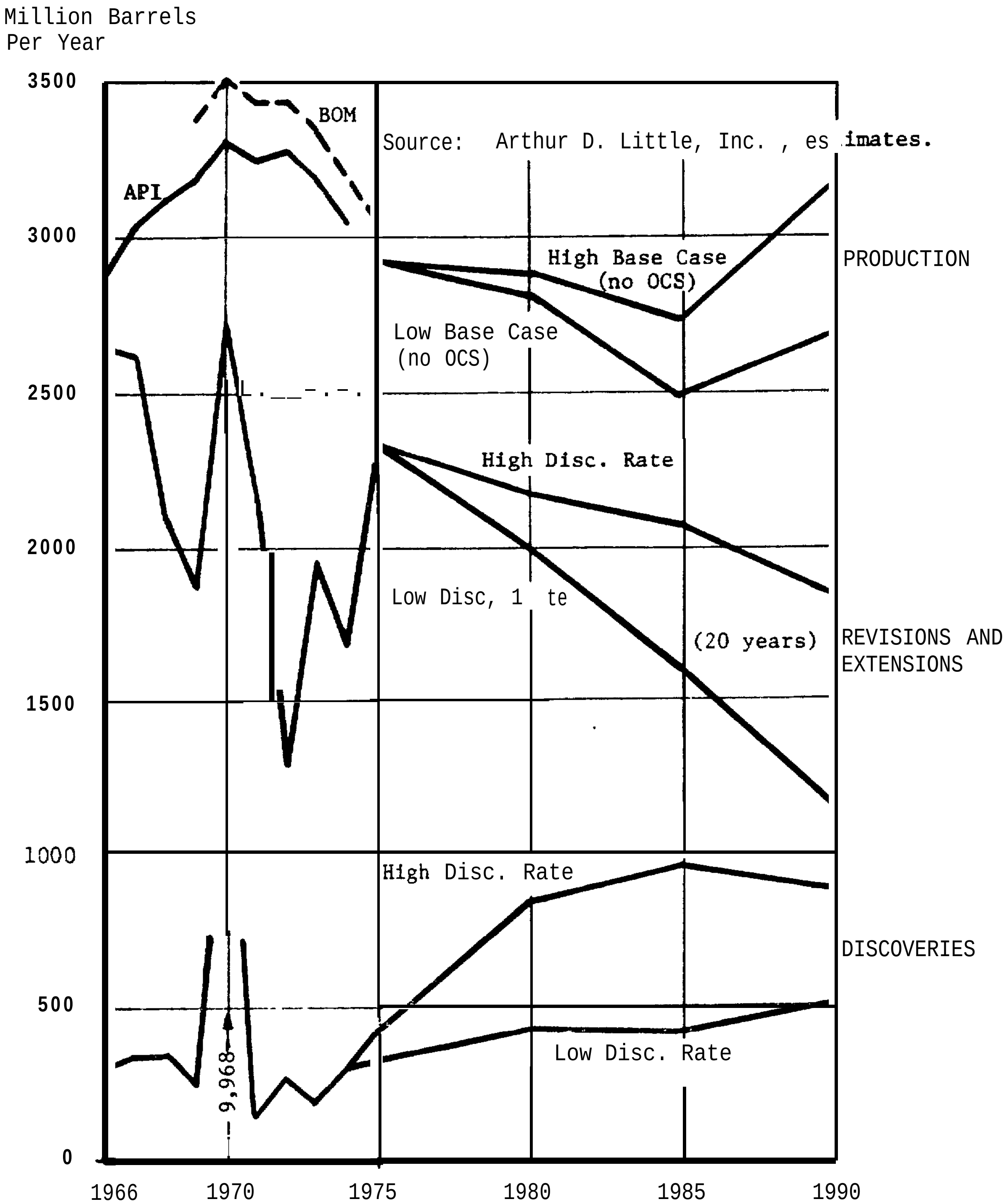


FIGURE IV.16 OIL - High and Low Base Case Projections of Discoveries, Revisions and Extensions and Production from Onshore and Existing Offshore Areas Off the U.S.A.

frc existing offshore areas consisted of estimates of declining prc. ction from 1975 production levels and of estimates of production from extensions and revisions to those reserves.

Under this scenario, the annual discovery rate for oil would grow from a level of 300 million barrels per year in 1974 to a peak of 960 million barrels per year in 1985 and declining thereafter (Figure IV.16). However, in spite of the increase in discovery rate total production of crude oil anc natural gas liquids from all areas under this scenario would continue to decline from the level of 9.65 million barrels per day in 1975 to 8.75 million barrels per day in 1985 followed by a period of steady growth in production capacity at a rate of about 2% per year to a level of about 9.8 million barrels per day in 1990 (Figure IV.17). The initial continuing decline in daily production between 1975 and 1985 is explained by the fact that at least ten years will be required before increases in accumulated daily production capacity resulting from increased newly discovered reserves will overtake the decline in daily production capacity from reserves which were discovered prior to 1975. Also, production by Extended Oil Recovery Methods was assumed to make significant contribution to overall production between 1980 and 1985.

Under this optimistic production scenario, the daily production capacity for gas would continue to decline until 1980, in spite of increases in discovery rates from the 1975 level of 3.75 trillion cubic feet per year to peak of 8.6 trillion cubic feet per year in 1985 (Figure IV.18). Following the year 1980 production capacity of non-associated and associated gas would start to grow slowly to around 55 trillion cubic feet per day in 1985 and 199(I from 51 trillion cubic feet per day in 1980. The earlier turnaround in production capacity by increase in annual discoveries, then shown for oil, would reflect the expected response from industry if prices for natural gas would be allowed to rise considerably relative to 1974 price levels.

A *pessimistic production forecast* was obtained assuming that a lack of economic incentives would result in relatively low, future, annual discovery rates, remaining at approximately the same level as realized in 1974. The future production levels for Alaska onshore (Prudhoe Bay) were prespecified. Projections of production from existing offshore areas were obtained by declining 1975 production levels and by estimating increases in productive capacity through extensions and revisions to reserves in those areas.

Under this scenario, daily production of crude oil and natural gas liquids would decrease from a level of 9.6 million barrels per day in 1975 at an average rate of 3-1/2% per year to 6.75 million barrels per day in 1985 (Figure IV.17). Starting around 1985 the production capacity would begin to increase again but this only because of oil production from the reserves in the onshore areas of Alaska (Prudhoe Bay). Without *this* incremental production *from* Alaska, production would bottom out at 5-1/2 million barrels a day in 1990. Extended Oil Recovery Methods were assumed not to make any significant contribution to overall production.

Production of associated and non-associated gas from existing and newly discovered fields onshore and from already discovered fields offshore would continue to decline from its level of 58 billion cubic feet per day in 1975 to 47 billion cubic feet per day in 1980, 44 trillion cubic feet per day in 1985 and 37 billion cubic feet per day in 1990 declining at an average rate of 3-1/2% per year between 1975 and 1990 (see Figure IV.19).

Million Barrels
MMB/Year

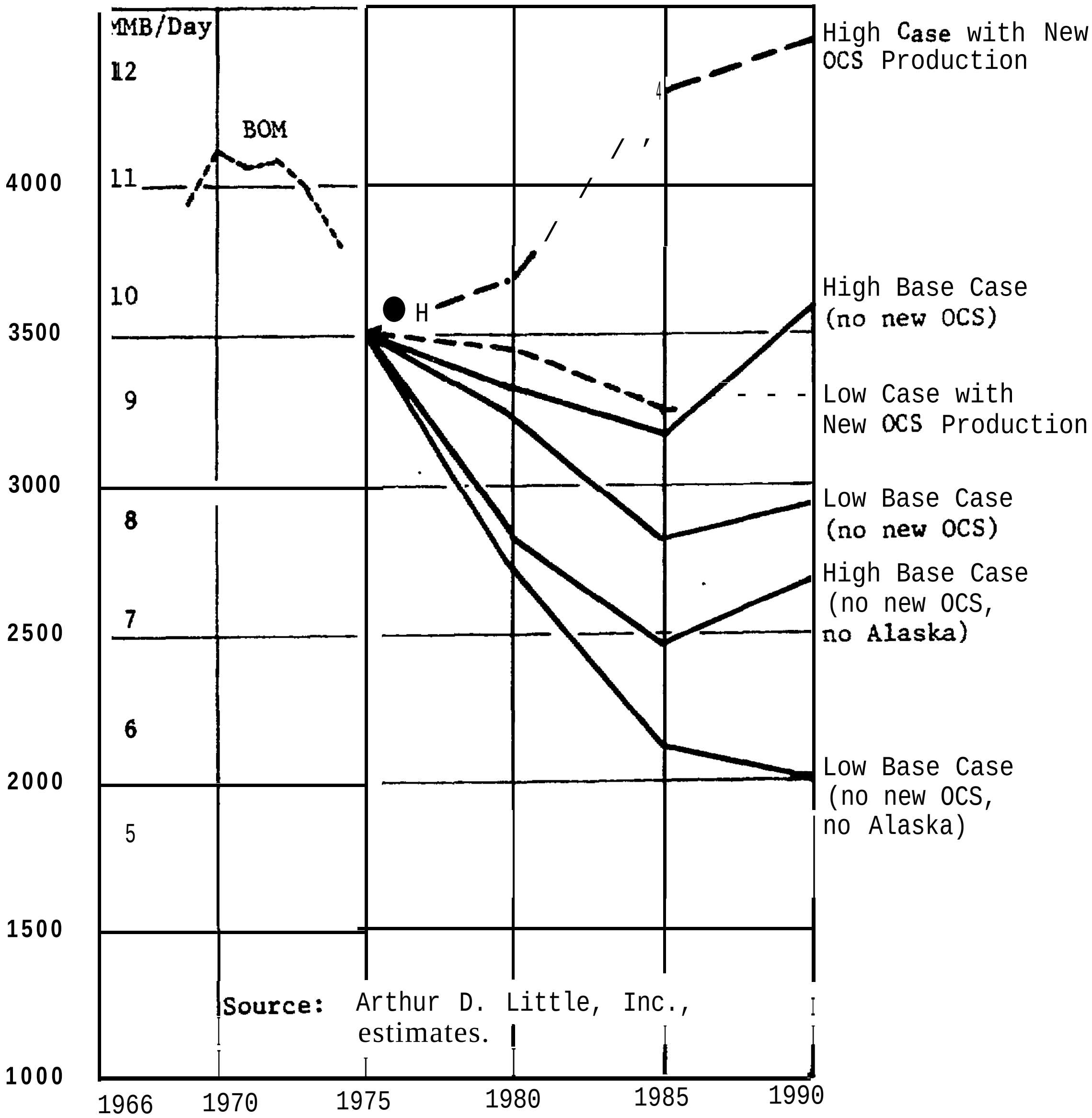


FIGURE IV.17 OIL AND NATURAL GAS LIQUIDS - High and Low Projection? of Production from Onshore and Existing Offshore Areas *With* AND *Without* Production from *New* OCS Areas of the U.S.A.

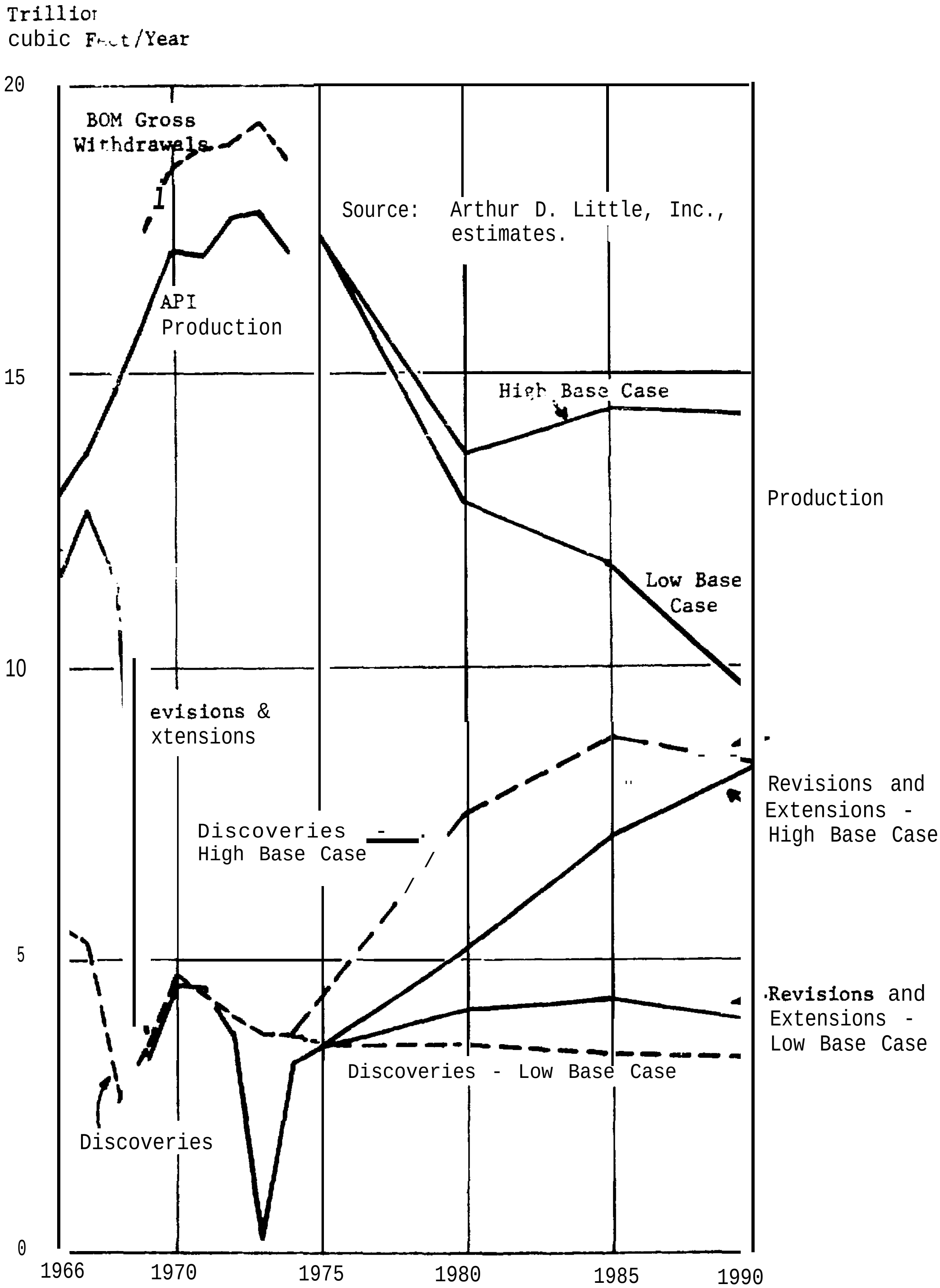


FIGURE IV.18 GAS - High and Low Base Case Projections of Discoveries, Revisions and Extensions, and Production from Onshore and Existing Offshore Areas of the U.S.A.

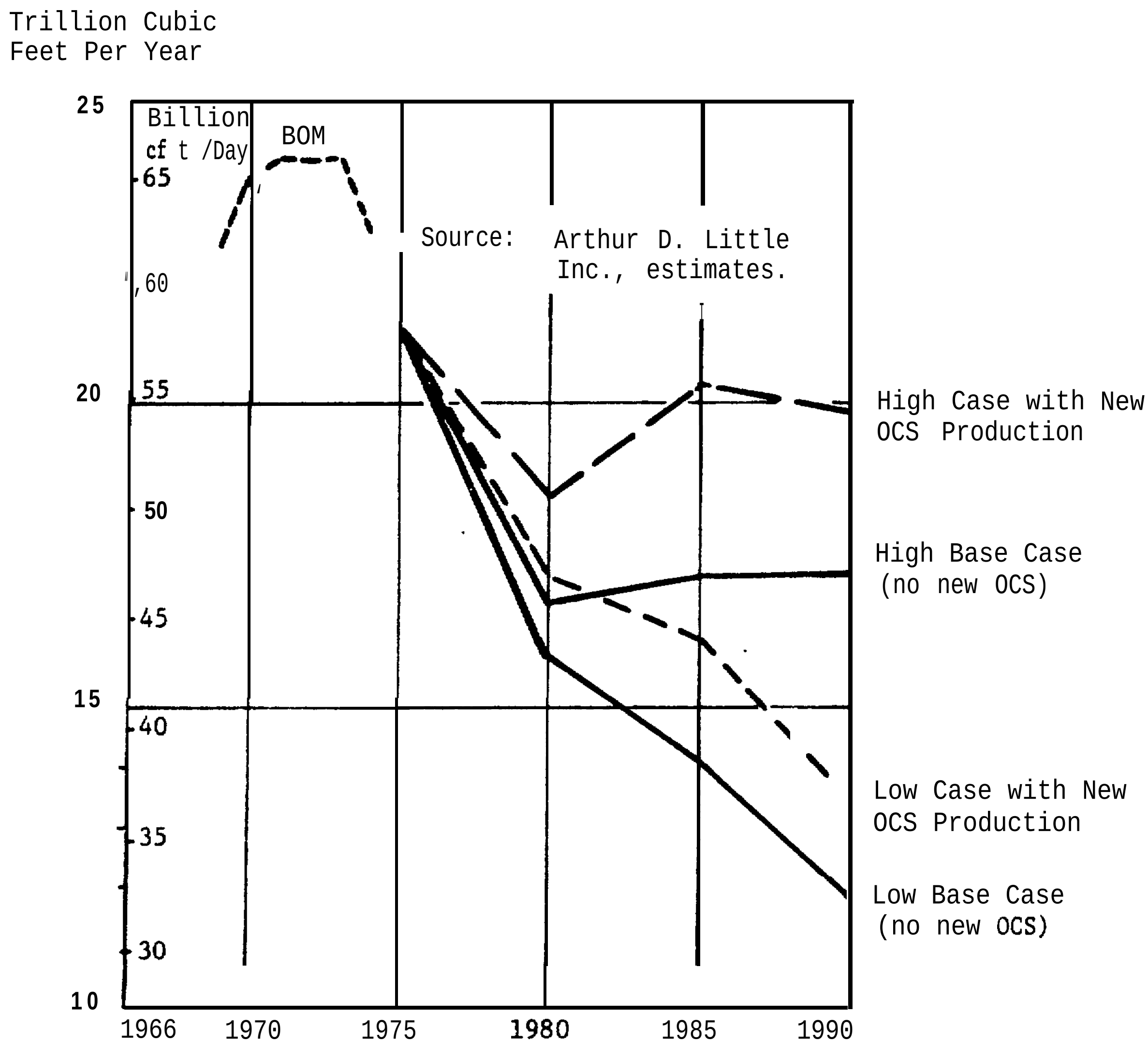


FIGURE IV.19 GAS AND ASSOCIATED GAS - High and Low Projections of Production from Onshore and Existing Offshore Areas *With* and *Without* Production from *New* OCS Areas of the U.S.A.

The Potential Impact of Future Production from New OCS Areas on the Overall Production Capacity of the United States is shown by adding our projections for OCS production under a high and low price scenario to the low and high projections from onshore areas and from existing offshore areas discussed above. The price scenarios assumed for expected oil and gas production from the new OCS areas were $12 per barrel and $1.25 per MCF, respectively, at the wellhead.

a. Total. Future Potential Production of Crude Oil and Natural Gas Liquids

Combination of the optimistic and pessimistic production forecasts for onshore areas and existing offshore areas with the production forecasts for new OCS areas were made under a high and low price scenario which provided the following results:

1. Under the optimistic/high price scenario -

- Total oil and natural gas liquids production would increase from a level of 9.6 million barrels per day in 1975 to about 10 million barrels per year in 1980, 11.6 million barrels per day in 1985 and 12.3 million barrels per day in 1990 (see Table IV-8);

- Relative contribution to total domestic production from offshore areas would grow from about 17-1/2% in 1975 to about 3L% in 1985 (see Table IV-8);

- About 36% of all OCS production in 1985 would come from areas offshore Alaska, about 24% from areas offshore the Pacific Coast, about 12% from areas offshore the Atlantic Coast and 28% from areas in the Gulf of Mexico;

- The contribution of total offshore production of crude oil and natural gas liquids would change between 1975 and 1985 (see Table IV-8);

  For Alaska, from 5-1/2% to 36% or from 0.15 million barrels per day to 1.35 million barrels per day;

  - For the Pacific, from 13% or 24% or from 0.21 million barrels per day to 0.85 million barrels per day;

  - For the Atlantic, from 0% to 12% or from 0.0 million barrels per day to 0.43 million barrels per day;

  - For the Gulf of Mexico, from 78% to 28% or from 1.23 million barrels per day to 1.04 million barrels per day.

TABLE IV-8

PROJECTIONS OF CRUDE OIL AND NATURAL GAS LIQUIDS PRODUCTION BY PRODUCING REGION

Optimistic Case (1)
(million barrels per day)

	YEAR				
	1974	1975	1980	1985	1990
Lower 48, old	8.67	7.92	5.89	4.24	3.38
Lower 48, new	0.00	0.00	0.71	1.98	3.52
Gulf of Mexico, old	1.36	1.23	0.88	0.33	0.30
Gulf of Mexico, new	0.00	0.00	0.36	0.71	0.60
Atlantic, new	0.00	0.00	0.24	0.43	0.29
Pacific, old	0.23	0.21	0.17	0.16	0.15
Pacific, new	0.00	0.00	0.27	0.49	0.50
Alaska onshore, new	0.03	0.08	1.37	1.92	2.47
Alaska offshore, old	0.16	0.15	0.09	0.05	0.03
Alaska offshore, new	0.00	0.00	0.02	1,30	1.11
Total	10.45	9.59	10.00	11,61	12.35

Pessimistic Case (2)

	1974	1975	1980	1985	1990
Lower 48, old	8.67	7.92	5,89	4.24	3.38
Lower 48, new	0.00	0.00	0.44	1.02	1.74
Gulf of Mexico, old	1.36	1.23	0.89	0.31	0.30
Gulf of Mexico, new	0.00	0.00	0.19	0.41	0.39
Atlantic, new	0.00	0.00	0.17	0.28	0.18
Pacific, old	0.23	0.21	0.18	0.16	0.15
Pacific, new	0.00	0.00	0.06	0.15	0.07
Alaska onshore, new	0.03	0.08	1.37	1.92	2.47
Alaska offshore, old	0.16	0.15	0.09	0.05	0.03
Alaska offshore, new	0.00	0.00	0.01	0.09	0.07
Total	10.45	9.59	9.28	8.65	8.78

(1) Assumptions:

1. For onshore areas other than Alaska, annual discoveries will increase at a rate of 11% per year from 300 million barrels of recoverable reserves in 1974 to 950 million barrels in 1985 and they will decline thereafter;

2. Production from onshore areas of Alaska will be as shown, mainly reflecting increases in production from the Prudhoe Bay area;

3. Production from offshore reserves, producing in 1975 will continue to decline as shown;

4. For new OCS areas expected production will be as found possible with a $12/bbl wellhead price for oil and a $1.25/MCF wellhead price for gas assuming an accelerated lease sale schedule through 1978;

5. Extended oil recovery methods will start to contribute significantly to overall production between 1980 and 1985.

(2) Assumptions:

1. For onshore areas other than Alaska. annual discoveries will increase at a rate of only 3.5% per year from 300 million barrels of recoverable reserves in 1974 to 500 million barrels of recoverable reserves in 1990;

2. Production from onshore areas of Alaska will be as shown, reflecting mainly increases in production from the Prudhoe Bay area;

3. Production from offshore reserves, producing in 1975, will continue to decline as shown;

4. For new OCS areas expected production will be aa found possible with a $4.50/bbl wellhead price for oil and a $0.75/MCF price for gas assuming an accelerated lease sale schedule through 1978;

5. Extended oil recovery methods will continue to contribute only marginally to overall production.

Source: Arthur D. Little, Inc. estimates.

2. Under the pessimistic/low price scenario -

- Total production of oil and natural gas liquids would slightly decrease from a level of 9.6 million barrels per day in 1975 to about 9.3 million barrels per day in 1980, 8.7 million barrels per day in 1985 and increase 8.8 million barrels per day in 1990;

- Relative contribution to the total domestic production from offshore areas would grow from about 17-1/2% in 1975 to about 19-1/2% in 1985;

- About 8% of all OCS production in 1985 would come from Alaska, 33% from the Pacific Coast areas, 16% from areas off the Atlantic Coast and 43% from areas in the Gulf of Mexico;

- The contribution to total offshore production of crude oil and natural gas liquids would change between 1975 and 1985 (see Table IV-8);

  - For Alaska, from 5-1/2% to 8% or from 0.15 million barrels per day to 0.14 million barrels per day;

  - For the Pacific, from 13% to 33% or from 0.21 million barrels per day to 0.57 million barrels per day;

  - For the Atlantic, from 0% to 16% or from O. million barrels per day to 0.28 million barrels per day;

  For the Gulf of Mexico areas, from 78% to 43% or from 1.23 million barrels per day to 0.74 million barrels per day.

b. Total Future Potential Production of Associated and Non-Associated Natural Gas

Combination of the optimistic and pessimistic production forecasts for onshore areas and existing offshore areas with the production forecasts for new OCS areas were made under a high and low price scenario which provided the following results.

1. Under the optimistic/high price scenario -

- Total associated and non-associated gas production would decrease from a level of 58.2 billion cubic feet per day in 1975 to about 50.6 billion cubic feet in 1980 and therefore increase to 55.6 billion cubic feet per day in 1985 and 54.3 billion cubic feet per day in 1990 (see Table IV-9);

TABLE IV-9

PROJECTIONS OF ASSOCIATED AND NON-ASSOCIATED NATURAL GAS PRODUCTION BY PRODUCING REGIONS

Optimistic Case (1)
(billions of cubic feet per day)

	YEAR				
	1974	1975	1980	1985	1990
Lower 48, old	49.30	46.11	30.88	21.07	12.49
Lower 48, new	0.00	0.00	6.71	16.72	27.26
Gulf of Mexico, old	12.53	11.40	7.76	5.03	1.87
Gulf of Mexico, new	0.00	0.00	3.24	5.07	4.13
Atlantic, new	0.00	0.00	0.78	1.25	0.98
Pacific, old	0.14	0.13	0.13	0.12	0.12
Pacific, new	0.00	0.00	0.54	1.03	0.77
Alaska onshore, new	0.34	0.34	0.34	4.00	5.48
Alaska offshore, old	0.24	0.22	0.16	0.11	0.08
Alaska offshore, new	0.00	0.00	0.03	1.19	1.17
Total	62.55	58.20	50.57	55.59	54.35

Pessimistic Case (2)

	1974	1975	1980	1985	1990
Lower 48, old	49.30	46.11	30.88	21.07	12.49
Lower 48, new	0.00	0.00	4.15	8.45	12.47
Gulf of Mexico, old	12.53	11.40	7.76	5.03	1.87
Gulf of Mexico, new	0.00	0.00	2.69	4.27	3.37
Atlantic, new	0.00	0.00	0.56	0.81	0.63
Pacific, old	0.14	0.13	0.13	0.12	0.12
Pacific, new	0.00	0.00	0.39	0.62	0.45
Alaska onshore, new	0.34	0.34	0.34	4.00	5.48
Alaska offshore, old	0.24	0.00	0.16	0.11	0.08
Alaska offshore, new	0.00	0.00	0.00	0.00	0.00
Total	62.55	58.20	47.22	44.49	36.98

(1) Assumptions:

1. For onshore areas other than Alaska, annual discoveries will increase at a rate of 9% per year from 3.75 trillion cubic feet of recoverable reserves in 1974 to 3.3 trillion cubic feet in 1985, and they will decline thereafter;
2. Production from onshore areas of Alaska will be as shown, mainly reflecting increases in production from the Prudhoe Bay area.
3. Production from offshore reserves, producing in 1975 will continue to decline as shown;
4. For new OCS areas expected production will be as found possible with a $12/bbl wellhead price for oil and a $1.25 MCF wellhead price for gas assuming an accelerated lease sale schedule through 1978.
5. Extended oil recovery methods will start to contribute significantly to overall production between 1980 and 1985.

(2) Assumptions:

1. For onshore areas other than Alaska, annual discoveries will decrease at a rate of 1% per year from 3.75 trillion cubic feet of recoverable reserves in 1974 to 3.2 trillion cubic feet in 1990;
2. Production from onshore areas of Alaska will be as shown, reflecting mainly increases in production from the Prudhoe Bay area;
3. Production from offshore reserves, producing in 1975, will continue to decline as shown;
4. For new OCS areas expected production will be as found possible with a $4.50/bbl wellhead price for oil and $0.75/MCF wellhead price for gas assuming an accelerated lease sale schedule through 1978.
5. Extended oil recovery methods will continue to contribute only marginally to overall production.

Source: Arthur D. Little, Inc., estimates.

- Relative contribution to total domestic production for offshore areas would grow from about 21% in 1975 to about 25% in 1985;

- About 73% of all OCS production in 1985 would come from the Gulf of Mexico areas, about 9% from areas offshore the Atlantic Coast, about 8% from areas offshore the Pacific Coast and about 10% from areas offshore Alaska;

- The contribution to total offshore production of associated and non-associated natural gas would change between 1975 and 1985 (see Table IV-9);

  - For Alaska, from 2% to 10% or from 0.22 billion cubic feet per day to 1.3 billion cubic feet per day;

  - For the Pacific, from 1% to 8% or from 0.13 billion cubic feet per day to 1.15 billion cubic feet per day;

  - For the Atlantic, from O% to 9% or from O million cubic feet per day to 1.25 billion cubic feet per day;

  - Fox the Gulf of Mexico, from 97% or 73% or from 11.4 billion cubic feet per day to 10.1 billion cubic feet per day.

2. Under the pessimistic/low price scenario -

- Total production of associated and non-associated gas would decrease significantly from a level of 58.2 billion cubic feet per day to 47.2 billion cubic feet per day in 1980, 44.5 billion cubic feet per day in 1985 and 37.0 billion cubic feet per day in 1990;

- Relative contribution to the total domestic production from offshore areas would grow from about 21% in 1975 to about 25% in 1985;

- About 85% of all OCS production in 1985 would come from the Gulf of Mexico, 7% from the areas off the Atlantic Coast, 7% from areas off the Pacific Coast, and 1% from offshore Alaska;

- The contribution to total offshore production of associated and non-associated natural gas would change between 1975 and 1985 (see Table IV.8);

  - For Alaska, from 2% to 1% or from 0.22 billion cubic feet per day to 0.11 billion cubic feet per day;

- For the Pacific, from 1% to 7% or from 0.13 billion cubic feet per day to 0.74 billion cubic feet per day;

- For the Atlantic, from 0% to 7% or from 0 billion cubic feet per day to 0.81 billion cubic feet per day;

- For the Gulf of Mexico from 97% to 85% or from 11.4 billion cubic feet per day to 9.3 billion cubic feet per day.

C. NATIONWIDE IMPACTS

1. Impact of OCS Oil Production on U.S. Petroleum Imports and Refining Utilization

To assess the Impact of possible future OCS oil and natural gas liquids on the nation's supply/demand balance, it was estimated how much of the projected available refining capacity would be required to process these additional production streams in the major refining centers of the U.S.

For that purpose, refining capacity utilization in 1975 for sixteen different refining centers and the relative amounts of crude oil and natural gas liquids from different domestic producing areas used in these refining centers were obtained from Bureau of Mines statistics (see Table IV-10). Projections of future refining capacity up to and including 1980 for these refining centers were made, allowing for planned new construction as reported in 1975/1976. The scope of this study did not allow for a detailed analysis of possible changes in available refinery capacity beyond 1980. Therefore, available refining capacity for the benchmark years 1985 to 1990 were assumed to be the same as found for 1980.

Domestic crude oil production as a percentage of refining capacity in the benchmark years 1980, 1985, and 1990 were calculated using an optimistic and a pessimistic scenario of crude oil and natural gas liquids production for all the onshore and offshore areas in the United States in each case both including and excluding production of new OCS areas. In allocating production from the different producing areas over the refining centers, it was assumed that refining centers would continue to use the same relative amounts of domestic crudes from different producing areas as used in 1974.

As discussed in the previous section, the optimistic production forecast consisted of:

- A high forecast of crude oil and natural gas production from onshore and existing offshore areas;
- This same high forecast *including* projections of expected crude and natural gas production from new Outer Continental Shelf areas under a price scenario, which assumed a wellhead price of $12 per barrel for oil and $1.25/MCF for gas.

The pessimistic production forecast consisted of:

- A low forecast of the crude oil and natural gas production from onshore and existing offshore areas;
- This low forecast *including* projections of expected crude oil anti natural gas liquids production from new OCS areas under a price scenario, which assumed a wellhead price of $4.50 per barrel for oil and $.75/MCF for gas.

TABLE IV- 10

MONTHLY AVERAGE DOMESTIC CRUDE RECEIPTS FOR

(JANUARY THROUGH DECEMBER 1975 - (000 BARRELS)

PROM / TO	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	TOTAL
1) Eastern Seaboard (1)	1,262	309	64	779		75	148	555		1,881	8	72		81			5,234
2) Illinois/Indiana/Michigan	55	2,698	494	60	548	2,408	211	6,882	4,060	14,408	280	1,097	49	3,023			36,273
3) Kansas			4,.?59		69	2,213	292	8		1,646	251	79	96	1,509			10,442
4) Kentucky/Ohio/Tennessee	220	1,534		804			292	6,408	127	5,279	4	b		379			15,053
5) Nebraska/Missouri/North & South Dakota			33		1,626	171			224	2,191		177		84			4,508
6) Oklahoma			80			8,368			192	3,829	3		23	63			11,5$8
7) Alabama/Arkansas/Mississippi	483	-					3,249	3,774		395							7,901
8) Louisiana	946	-					1,3s7	30,577		6,148							39,028
9) New Mexico					.				2,424		?/		1		2	:.	2,459
10) Texas	1,117	-	29			391	817	6,667	877	66,135	138		283				16,476
11) Colorado											740	21	237	677			1,675
12) Montana						. -						1,368		1,489			2,657
13) Utah											1,425	73	1,528	569			3,600
14) Wyoming											153	40	65	2,83?			3,095
15) Western Seaboard (2)											130		1,055	-	26,924	3,757	32,066
16) Alaska/Hawaii																1,82?	1,828
TOTALS	4,083	4,541	4,959	1,643	2,243	13,646	6,?56	54,871	7,904	101.914	3.164	2,738	3,337	10,711	26,926	5.807	254,858

1) Delaware/Maryland/Ylorida/Georgia/Virginia/New Jersey/New York/Pennsylvania (zP.A.D.I.)

2) California/Oregon/Washington (zP.A. D. V.)

source : Arthur D. Little, Inc., estimates.

3. Total Domestic Production and Projected Refining Capacity

The projected refining capacity for each of the sixteen refining centers and the optimistic and pessimistic crude oil and natural gas liquids forecast, including the expected OCS production, are shown in Table IV-11.

These projections show that:

- Estimated future available refining capacity is expected to grow at 2% per year between 1975 and 1980. This growth can be broken down into a growth of 5% per year for the eastern seaboard refineries, 2% per year for refineries in Louisiana, 3% per year for refineries in Texaa, 3% per year for refineries in western seaboard and 3% per year for refineries in Alaska. Refining capacity in the other eleven areas considered are expected to grow only slightly between 1975 and 1980;

- Under the optimistic production forecast overall production is expected to grow at 2% per year from 1975 to 1985 or from 9.6 million barrels per day to 11.8 million barrels per day and at slightly less than 1% per year between 1985 and 1990 or from 11.8 million barrels per day in 1985 to 12.3 million barrels per day in 1990. This growth until 1985 is a result of a significant growth in production of oil and natural gas liquids in the eastern seaboard, the western seaboard and Alaskan onshore and offshore areas which offsets the decline in production shown to occur in the other onshore areas apart from New Mexico and Colorado. The production in the eastern seaboard areas is expected to grow at about 16% per year from 1975 to 1985 or from 120,000 barrels per day to 550,000 barrels per day. The western seaboard production is expected to grow at 7% per year or from .8 million barrels per day to 1.60 million barrels per day. Production from Alaska is expected to grow at 30% per year from .23 million barrels per day to 3.27 million barrels per day. Increases in production in onshore areas, apart from Alaska, is expected only to take place in New Mexico and Colorado. There the production under this optimistic scenario is projected to increase from 330,000 barrels per day in 1975 to 424,000 barrels per day in 1985 for New Mexico and from 104,000 barrels per day in 1975 to 148,000 barrels per day in 1985 for Colorado. As explained in the previous section, production in most of the areas is supposed to increase between 1985 and 1990 as a result of the increase in discovery rates between 1975 and 1985. This increase in production rates in the onshore areas will offset the decrease in production rates in the Outer Continental Shelf areas where production from areas leased through 1978 is expected to decline between 1985 and 1990.

TABLE IV-11

PROJECTED REFINING CAPACITY[1] AND
PROJECTED DOMESTIC PRODUCTION OF CRUDE OIL
AND NATURAL GAS LIQUIDS BY REFINING CENTER
(in million bls per year)

Projected Ref. Capacity by Ref. Center

	1974	1975	1980	1985	1990
Eastern Seaboard	643	643	828	828	828
111/Ind/Mich/Wise	760	768	768	768	"768
Kansas	165	166	166	166	166
Kent/Ohio/Term	292	292	292	292	292
Neb/Miss/N.S. Dak	135	142	142	142	142
Oklahoma	184	201	206	206	206
Ala/Ark/Mississ	145	175	175	175	175
Louisiana	649	657	741	741	741
New Mexico	42	43	43	43	43
Texas	1454	1468	1715	1715	1715
Colorado	22	23	23	23	23
Montana	59	59	59	59	59
Utah/Idaho	56	56	56	56	56
Wyoming	68	68	68	68	68
Western Seaboard	834	839	979	979	979
Alaska/Hawaii	53	64	75	75	75
Total	5558	5664	6337	6337	6337

Production Forecast by Ref. Center
OPTIMISTIC, INCLUDING OCS

	1974	1975	1980	1985	1990
Eastern Seaboard	50	46	126	201	161
111/Ind/Mich/Wise	52	48	34	34	52
Kansas	78	72	64	68	76
Kent/Ohio/Tern	20	19	17	18	25
Neb/Miss/N.S.Dak	27	24	19	21	29
Oklahoma	235	215	152	137	106
Ala/Ark/Mississ	87	79	57	27	30
Louisiana	898	824	788	600	571
New Mexico	133	122	131	155	169
Texas	1556	1415	1097	1005	1039
Colorado	41	38	39	54	78
Montana	36	33	25	14	24
Utah/Idaho	40	38	35	32	54
Wyoming	151	139	130	157	188
Western Seaboard	333	307	434	594	575
Alaska/Hawaii	71	84	538	1193	1317
Total	3807	3503	3687	4311	4494

Production Forecast by Ref. Center
PESSIMISTIC INCLUDING OCS

	1974	1975	1980	1985	1990
Eastern Seaboard	50	46	95	132	100
111/Ind/Mich/Wise	52	48	31	26	38
Kansas	78	72	59	52	46
Kent/Ohio/Term	20	19	15	12	15
Neb/Miss/N.S.Dak	27	24	18	16	18
Oklahoma	235	215	143	106	47
Ala/Ark/Mississ	87	79	55	24	24
Louisiana	898	824	725	486	486
Nev Mexico	133	122	124	131	123
Texas	1556	1415	1062	885	813
Colorado	41	38	34	37	44
Montana	36	33	23	8	12
Utah/Idaho	40	38	31	19	28
Wyoming	151	139	118	113	105
Western Seaboard	333	307	384	456	439
Alaska/Hawaii	71	84	533	751	937
Total	3807	3503	3453	3254	3276

Source: Arthur D. Little, Inc., estimates

[1] Projections for 1980 based on planned construction and expansion; available capacity in 1985 and 1990 assumed to be the same as in 1980.

- In *the pessimistic production scenario* production increases from the Outer Continental Shelf areas between 1975 and 1985 will not be enough to offset the production decline in the onshore areas. The overall production will decline at somewhat less than 1% per year between 1975 and 1985. Between 1985 and 1990, however, production is expected to increase, albeit very little, by the small increase in discovery rates assumed to take place between 1975 and 1985. The expected increase in production from the Outer Continental Shelf areas amount to 11% per year between 1975 and 1985 in the eastern seaboard areas or from 120,000 barrels per day to 361,000 barrels per day, and at about 4% per year from 1975 to 1985 in the western seaboard areas or from 840,000 barrels per day in 1975 to 1.25 million barrels per day in 1985. The increase in production from Alaska is expected, under this pessimistic scenario, to be about 25% per year between 1975 and 1985 or increasing from 230,000 barrels per day in 1975 to 2 million and 58,000 barrels per day in 1985. As under the optimistic forecast, production from those Outer Continental Shelf areas, which are assumed to be leased through 1978, is expected to decline between 1985 and 1990 and production from other areas in general are expected to increase due to the slight increase in discovery rates between 1975 and 1985.

b. <u>Required Refining Capacity for New OCS Oil</u>

Crude oil and natural gas liquids production from *other than OCS* areas under the optimistic scenario will provide for 5% to 10% more available refinery capacity as under the pessimistic scenario. Production *from Outer Continental Shelf* areas in 1985 can provide for an addition 4% to 5% of available refining capacity under the pessimistic scenario and an additional 6% to 18% under the optimistic scenario (see Figure IV.20). With production from new OCS areas *import requirements* for refineries in the U.S. may be reduced by 10% to 15% in 1980, 10% to 30% in 1985 and 1990.

The largest impact by OCS production is expected to occur in the western seaboard and Alaskan refinery centers where capacity will have to grow at 2% per year between 1980 and 1990 under the pessimistic scenario and 6% per year between 1980 and 1990 under the optimistic scenario. Available OCS oil in those combined refining centers will require as much as 75% additional capacity in 1985 under the optimistic scenario (see Figure IV.21).

If OCS oil and NGL liquids are not available from new OCS areas, then for all other refining centers it can be expected that domestic crude availability will decrease relative to the projected refining capacity until 1985 to a slight increase between 1985 and 1990 relative to 1985 1985 levels (see Figure IV.21). New supplies from OCS areas

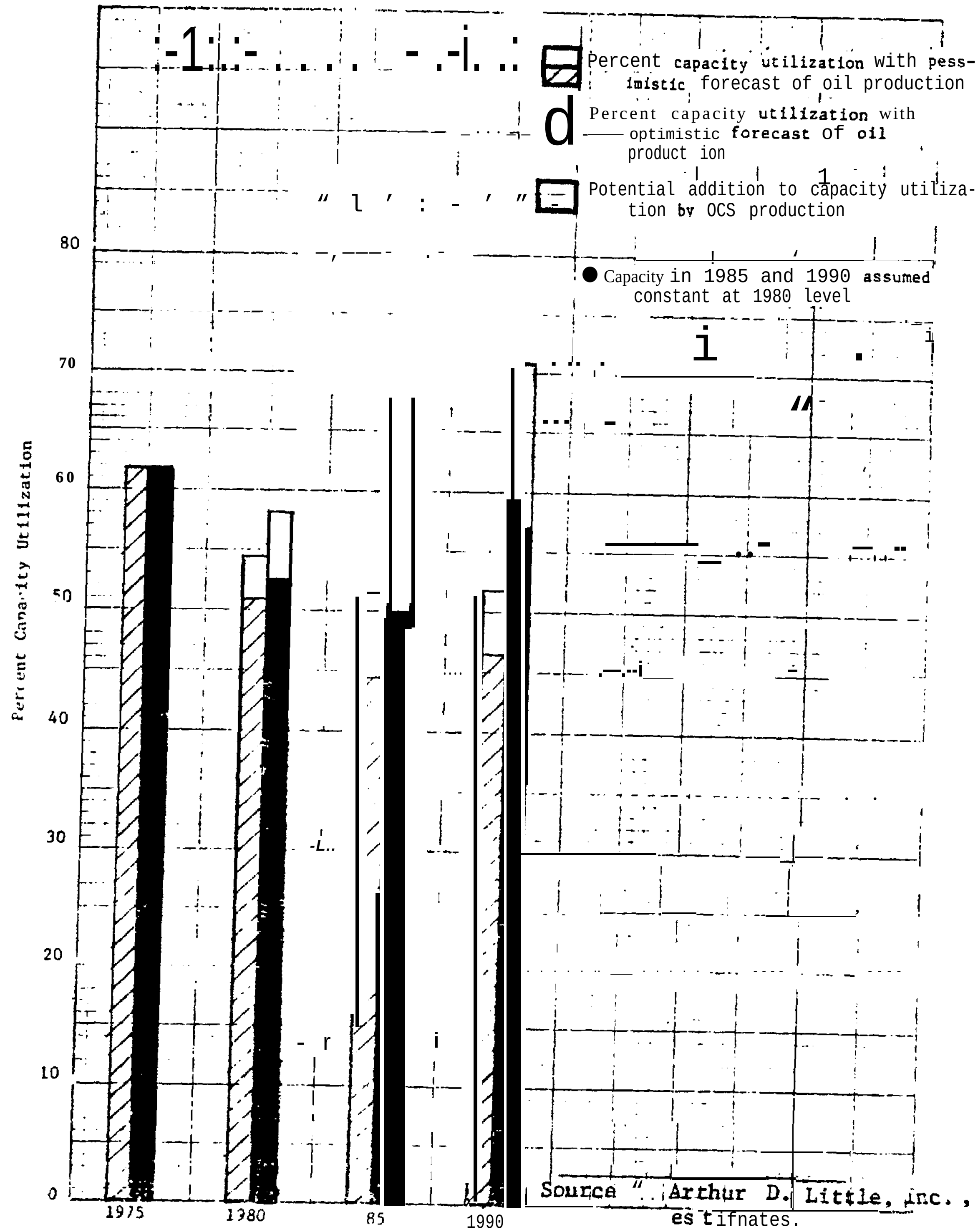


FIGURE IV. 20 Total U. S. Domestic Crude Oil Production as a percent of Refining Capacity

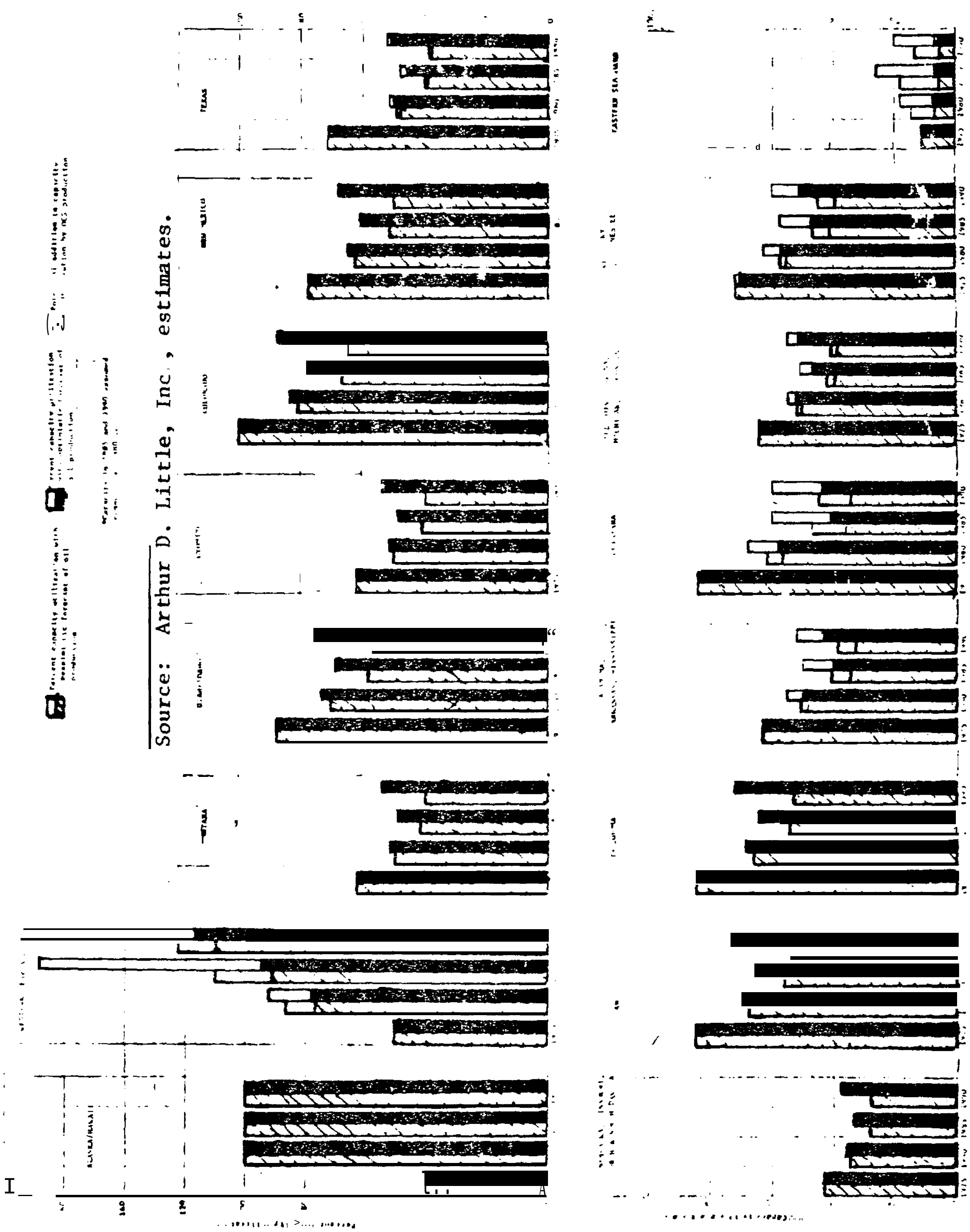


FIGURE IV.21 Regional Domestic Crude Oil a-s a Percent of Refining Capaci ty will only change this trend substantially in the eastern seaboard refining center which historically relied mostly on imported crudes. As shown in Figure IV.21, OCS crude oil and NGL liquids can increase the relative amount of domestic crude oils processed in refineries there from about 10% in 1975 to as much as 25% in 1985. Depending on their proximity to the potentially producing areas on the OCS, import requirements can be substantially reduced in other refining centers also by production from new OCS areas.

2. Impact of OCS Gas Production on U.S. Natural Gas Curtailment Potential

In assessing the ability of OCS natural gas production to substantially alleviate anticipated shortfalls in natural gas supply, three scenarios of OCS natural gas idstribution among states were examined to determine regional impacts of both added supplies from OCS areas and the manner in which these added supplies might be distributed. All scenarios follow the Federal Power Commission curtailment priorities in allocating available supplies first to residential and commercial users and lastly to industrial users and electric utilities.

The first scenario assumed that all natural gas - from onshore as well as OCS production, Imports, and other supplemental sources - would be distributed among the states such that any shortfall in supply would be shared proportionately among all states. The other two scenarios assumed that producing states would retain as much of their onshore production needed to satisfy state demand; surplus onshore production, OCS production and other sources of natural gas would then be distributed nationally in one scenario and regionally in the other. These three scenarios are discussed in more detail below following a discussion of the assumptions employed in the demand and supply projections.

a. Demand and Supply

In order to maintain a basis for meaningful comparison between demand and supply of natural gas, projections have been based on Bureau of Mines historical statistics of gross withdrawals in the case of supply and of final deliveries to consumers in the case of demand. Our estimates of natural gas demand in 1975, 1980, 1985 and 1990 is shown in Table IV-12 by census division region and end-use sector. Compared with 1974 demand (Table IV-13), residential and commercial requirements are expected to increase as a percentage of total demand while industrial and electric utility needs are expected to show a relative decrease, although industrial users are anticipated to remain the highest volume users through 1990. Residential demand is projected to increase from 25.1% of all 1974 natural gas deliveries to 31.3% of 1990 demand, commercial needs are expected to increase from 11.9% of all users in 1974 to 18.2% of 1990 demand, industrial demand is estimated to decrease from 43.5% of the 1974 total to 40.9% in 1990 and electric utility requirements are anticipated to drop from 18% of 1974 deliveries to under 8% of total demand in 1990.

TABLE IV-12

PROJECTION OF U.S. NATURAL GAS DEMAND BY REGION AND END-USE SECTOR 1975-1990

REGION	1975 Residential	1975 Commercial	1975 Industrial	1975 Electric Utilities	1975 Other	1975 Total	1980 Residential	1980 Commercial	1980 Industrial	1980 Electric Utilities	1980 Other	1980 Total
New England	143.3	59.8	49.9	9.1	5.4	267.5	173.1	79.7	57.9	9.8	8.9	329.2
Middle Atlantic	764.9	280.9	496.3	64.6	27.3	1633.8	2351.5	347.2	558.3	86.3	27.9	[illegible]871.2
E. North Central	1553.0	740.1	1626.9	157.6	29.5	4107.1	1741.0	912.0	1792.1	127.0	30.8	[illegible]603.0
W. North Central	532.3	315.1	587.6	345.0	58.1	183/3.1	590.b	364.3	565.0	266.1	62.3	[illegible]848.2
South Atlantic	343.3	186.1	613.6	236.1	29.1	1408.1	415.7	225.0	606.3	218.4	28.3	1493.7
E. South Central	207.9	127.9	497.8	38.1	22.7	894.4	230.4	143.4	473.5	13.9	22.2	883.4
W. South Central	442.1	192.7	3244.2	1323.6	76.8	5271.5	499.7	219.7	3206.4	163.1	76.4	[illegible]165.3
Mountain	362.5	162.3	382.5	178.8	[illegible]9.1	1015.8	31[illegible].9	202.1	375.[illegible]	93.9	36.7	1028.3
Pacific	657.0	281.8	835.6	335.2	16.9	2126.4	741.5	333.7	9[illegible].5	495.8	20.5	[illegible]514.1
Total U.S.	4906.4	2346.6	8334.2	[illegible]687.9	95.4	8570.6	5563.4	2[illegible]7.0	8557.6	1474.3	[illegible]14.0	3736.4
% of Total	26.4	12.6	44.9	14.5	1.6	100.0	29.7	5.1	45.6	7.9	1.7	100.0
	1985						**1990**					
New England	209.1	106.3	67.1	10.5	20.7	413.7	252.6	1[illegible]42.0	77.9	11.3	65.8	549.7
Middle Atlantic	949.0	439.1	628.6	117.8	28.7	2163.3	10$8.7	569.	708.9	163.8	29.5	2530.1
E. North Central	1953.6	1128.7	1976.2	114.9	32.3	5205.7	2194.2	1402.4	2181.5	112.8	33.9	5924.7
W. North Central	655.6	421.7	545.4	211.1	70.6	1904.3	728.0	488.8	528.4	171.3	87.7	2004.1
South Atlantic	505.4	276.8	612.7	203.4	27.8	1626.1	616.9	346.9	631.2	190.5	27.6	1813.1
E. South Central	255.4	160.9	453.4	10.5	21.8	902.0	283.4	180.7	437.0	10.6	21.4	933.1
W. South Central	565.5	250.7	3216.4	0	75.9	4108.5	640.6	286.4	3279.1	0	75.5	4281.5
Mountain	392.6	253.4	400.4	57.8	45.9	1150.1	485.6	319.9	460.8	39.1	58.4	1363.8
Pacific	840.6	395.6	1022.2	734.1	25.1	3017.7	958.0	469.9	1136.9	1087.4	30.9	3683.0
Total U.S.	6326.7	3433.2	6922.5	1460.1	48.8	0491.3	7218.0	4206.0	9441.7	1786.7	430.7	3083.0
% of Total	30.9	16.8	43.5	7.1	1.7	100.0	31.3	18.2	40.9	7.7	1.9	100.0

NOTE: Numbers may not add due to rounding.

Source: Arthur D. Little, Inc., estimates.

TABLE IV-13

1974 DELIVERIES OF NATURAL
GAS BY REGION AND END-USE SECTOR
(billion cubic feet)

State Region	Residential	Commercial	Industrial	Electric Utilities	Other	Total
Alabama	55	34	159	5	1	254
Alaska	4	7	14	17	6	48
Arizona	32	31	65	40	2	170
Arkansas	44	30	158	40	1	273
California	580	220	642	293	9	1744
Colorado	92	63	78	66	5	305
Connecticut	33	16	16	1	1	66
Delaware	7	3	9	1	0	20
Florida	15	19	92	155	4	284
Georgia	76	41	162	43	3	325
Hawaii	0	0	0	0	0	0
Idaho	'3	7	31	0	1	49
Illinois	462	213	410	43	3	1130
Indiana	158	74	271	14	2	519
Iowa	92	61	133	61	3	350
Kansas	93	50	165	165	3	477
Kentucky	76	35	74	5	7	197
Louisiana	92	29	1091	344	29	1585
Maine	1	1	0	0	0	2
Maryland	83	36	58	14	7	197
Massachusetts	85	34	24	7	4	155
Michigan	346	182	330	56	7	922
Minnesota	113	60	106	38	30	348
Mississippi	29	15	124	42	11	221
Missouri	153	74	110	48	16	401
Montana	22	14	35	1	2	75
Nebraska	49	38	70	48	4	210
Nevada	9	8	9	31	6	63
New Hampshire	4	2	2	0	0	8
New Jersey	136	57	65	15	1	275
New Mexico	25	13	64	67	12	182
New York	341	119	109	38	18	624
North Carolina	27	17	87	1	4	136
North Dakota	10	12	3	0	0	24
Ohio	436	183	425	21	10	1074
Oklahoma	73	38	147	294	3	555
Oregon	22	13	55	0	0	91
Pennsylvania	272	94	311	8	8	693
Rhode Island	13	4	4	2	1	24
South Carolina	20	14	73	22	1	130
South Dakota	11	11	5	4	1	32
Tennessee	44	41	147	0	4	235
Texas	223	91	1861	1335	43	3552
Utah	50	6	57	3	0	116
Vermont	2	1	1	1	0	5
Virginia	48	27	51	5	8	139
Washington	36	32	108	0	1	177
West Virginia	54	23	86	0	2	165
Wisconsin	116	59	160	34	7	376
Wyoming	12	13	47	1	1	74
Total U.S.	4786	2263	8306	3429	293	19077
% of Total	25	12	43	8	2	100

Source: Arthur D. Little, Inc., estimates.

This demand forecast was derived from the projections of natural gas consumption as prepared by the Gas Requirements Committee*, with certain modifications to allow for changes in the supply/demand situation since 1973, when the projections were made.

In the case of electric utility demand for natural gas certain modifications were deemed necessary in light of the current trend to regulate utility usage of this fuel. In particular, it has been assumed that the regulatory environment represented by the Texas Railroad Commission's required reduction of natural gas as a boiler fuel will intensify in the Gulf Coast area. For Arkansas, Louisiana, Mississippi, Oklahoma and Texas a 34.2% annual decrease in electric utility natural gas use is anticipated with such usage phased out completely by 1985. Since natural gas delivered to electric utilities in these states represented nearly 11% of total 1974 deliveries of natural gas, this assumption could be critical to the study results and has therefore been examined in the sensitivity analyses discussed later.

For the total U.S., demand is expected to grow at only 0.2% a year between 1975 and 1980, primarily due to a rapid decrease (11.3% per year) in electric utility demand as usage of natural gas as a boiler fuel is phased out. Between 1980 and 1985 the decrease in electric utility requirements is estimated to slow to .2% a year and consequently overall U.S. demand is projected to grow annually at a rate of 1.8% between those years. From 1985 to 1990 the annual growth in total U.S. demand for natural gas is expected to increase further to 2.4%. From 1975 to 1990, average annual growth rates in U.S. natural gas demand are estimated at 2.6% for residential, 4.0% for commercial, .8% for industiral, -2.7% for electric utilities and 2.5% for other users. This represents an overall annual growth in demand for the U.S. of 1.5% for the 15-year period.

To determine the amount of gas available as final deliveries to customers, our projections of domestic natural gas production were reduced by 20% to allow for gas used for repressuring and for gas lost by venting and flaring, by extraction in natural gas liquids plants and during transmission to the point of delivery.

To assess the potential impact of new gas supplies from OCS areas, the projected demand for natural gas on a state by state basis was compared with four different projections of natural gas supplies (see section IV.B.3):

- A pessimistic forecast of onshore production and production from existing offshore fields but excluding gas from new OCS areas (the "Pessimistic Base Case"};

- The same pessimistic forecast including a pessimistic forecast of expected OCS production (the "Pessimistic Case with OCS");

Future Gas Consumption of the United States, Volume 6, Gas Requirements Committee, Denver Research Institute, Univ. of Denver, Colorado, 1975.

- An optimistic forecast of onshore production and production from existing offshore fields excluding gas from new OCS areas (the "optimistic Base Case");

- The same optimistic forecast including an optimistic forecast of OCS production (the "Optimistic Case with OCS").

Estimates of supplemental sources of natural gas are shown by state in Table IV-14 and include Canadian imports, LNG imports, coal gasification, SNG, and other sources. Estimates of Canadian imports assume construction of a pipeline from Arctic fields such that Arctic imports are available by 1985. This projection of supplies from coal gasification may also be considered optimistic. These two assumptions regarding supplemental sources are examined further in the sensitivity analyses.

b. Projected Shortfalls

Table IV-15 provides the total U.S. shortfall in natural gas supply relative to projected demand under each of the four cases of assumed supply. The percentage shortfall is graphed in Figure IV.22 showing potential decreases in shortfall that might be expected with OCS production under either a pessimistic or an optimistic supply forecast. The results indicate that:

- Under a pessimistic forecast of supply, OCS production could reduce supply shortfalls as much as 36% in 1985 - from 22% to 14% of total demand - and by 1990 could reduce the shortfall from 32% of demand to 26%. "

- Under an optimistic forecast of both onshore and OCS production: a 42% reduction in the supply shortfall for 1980 with OCS production - a drop in shortfall from 17% to 10% of demand - could be expected. By 1985 OCS production could turn a 10% shortfall into a 450 billion cubic feet surplus and by 1990 the optimistic forecast of OCS production shows supply shortages reduced by 67 percent, from 13 to 4% of total demand.

In order to assess the regional impacts of these overall U.S. shortfalls in supply, three scenarios of supply distribution were examined. The first assumed that future allocations of natural gas supply would be guided above all by end-use priorities and that available supplies would be distributed nationally to satisfy all residential requirements first, then commercial demand, next "other" and industrial users and finally electric utility needs. Under this National Distribution Scenario, therefore, any shortfall would be shared proportionately among all states.

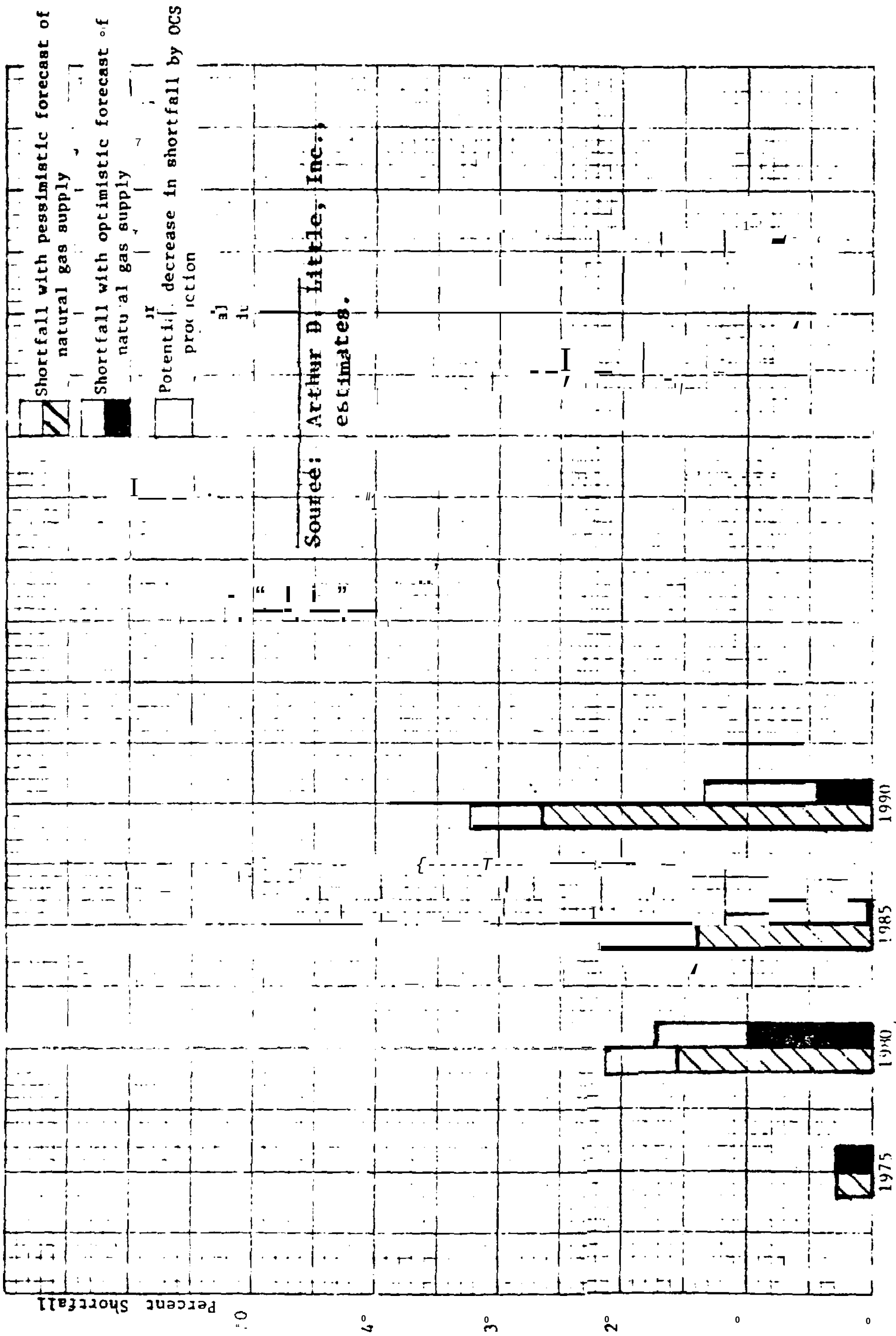


FIGURE IV.22 Total U. S. Shortfalls in Natural Gas Supply

TABLE IV-14

SUPPLEMENTAL SOURCES OF NATURAL GAS BY STATE

	1974	1975	1980	1985	1990
IMPORTS					
California	0	0	0	500	500
Idaho	405	385	340	0	0
Illinois	0	0	0	400	400
Minnesota	256	245	215	200	200
Montana	48	45	40	50	50
New York	5	5	5	0	0
Oregon	0	0	0	200	200
Vermont	5	5	5	0	0
Washington	239	225	195	200	200
Wisconsin	0	0	0	150	150
Total U.S.	958	910	800	1700	1700
LNG					
California	0	0	0	200	300
Geogia	0	0	165	260	300
Louisiana	0	0	0	0	160
Maryland	0	0	300	500	700
Massachusetts	10	15	35	40	40
New York	0	0	100	100	100
Rhode Island	0	0	100	100	100
Total U.S.	10	15	700	1200	1700
COAL GASIFICATION					
Illinois	0	0	50	250	400
Kentucky	0	0	0	100	200
New Mexico	0	0	50	250	300
North Dakota	0	0	50	200	300
Pennsylvania	0	0	0	100	100
Wyoming	0	0	0	100	200
Total U.S.	0	0	150	1000	1500
SNG					
Illinois	30	50	70	90	90
Maryland	0	0	10	10	10
Massachusetts	0	10	15	30	30
Michigan	15	30	40	40	40
New Jersey	10	50	75	100	100
New York	15	20	40	70	70
Ohio	10	40	50	60	60
Total U.S.	80	200	300	400	400
OTHER					
California	0	0	50	100	200
Colorado	0	0	50	100	150
Illinois	0	0	0	50	100
Maryland	0	0	0	50	75
Nev Jersey	0	0	0	40	75
Pennsylvania	0	0	25	50	75
Texas	0	o	25	50	100
Utah	0	0	0	60	100
Virgiria	0	0	25	50	100
West Virginia	0	0	25	50	125
Total U.S.	0	0	200	600	1100
TOTAL SUPPLEMENTS	1046	1125	2150	4900	6400

Source: Arthur D. Little, Inc., estimates.

TABLE IV-15

TOTAL U.S. SHORTFALL IN NATURAL GAS SUPPLY
(Billions of Cubic Feet)

	1975	1980	1985	1990
Total U.S. Demand	18,579.55	18,736.36	20,491.29	23,083.03
supply				
Pessimistic Base Case	18,051.25	14,757.79	16,010.73	15,671.25
Pessimistic Case with OCS	18,051.25	15,826.61	17,641.77	16,976.90
Optimistic Base Case	18,051.25	15,510.20	18,435.65	20,006.21
Optimistic Case with OCS	18,051.25	16,854.33	20,939.25	22,074.18
Shortfall - Billion Cubic Feet				
Pessimistic Base Case	519.3	3,978.57	4,489.56	7,411.78
Pessimistic Case with OCS	519.3	2,909.75	2,849.53	6,106.13
Optimistic Base Case	519.3	3,226.16	2,055.65	3,076.82
Optimistic Case with OCS	519.3	1,882.03	0.0	1,008.85
Shortfall - Percent				
Pessimistic Base Case	2.80	21.23	21.87	32.11
Pessimistic Case with OCS	2.80	15.53	13.91	26.45
optimistic Base Case	2.80	17.22	10.03	13.33
Optimistic Case with OCS	2.80	10.04	0.0	4.37

Source: Arthur D. Little, Inc., estimates.

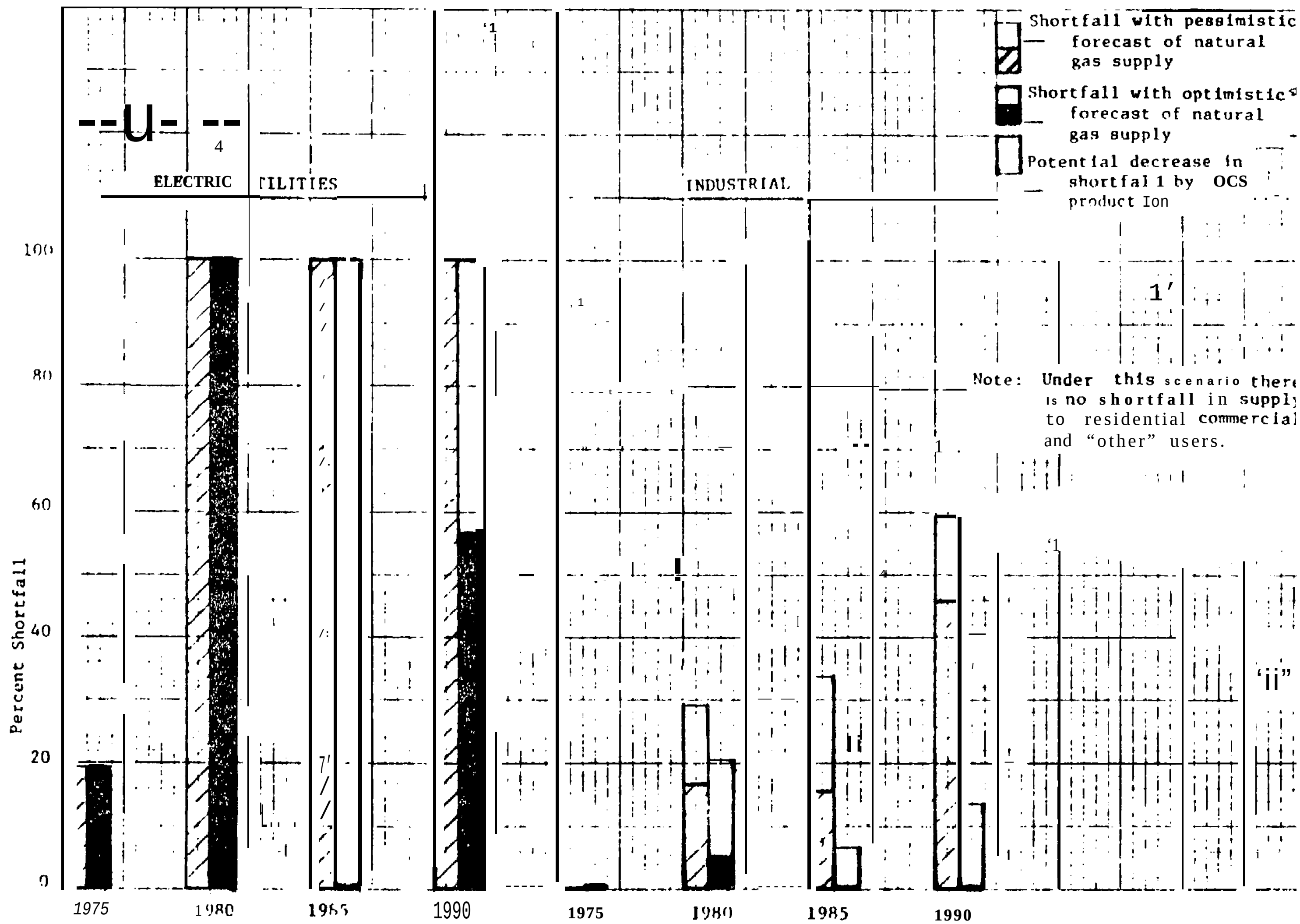
Figure IV.23 shows the total U.S. percentage shortfall (and correspondingly that of each state and region) by end-use sector under both pessimistic and optimistic forecasts of supply, assuming national distribution. If a pessimistic forecast is assumed, with or without OCS production, electric utilities would be curtailed 100%. Industrial use would experience as much as a 60% shortfall by 1990, which could be reduced to approximately 46% with OCS production. Under an optimistic forecast without OCS production, utilities would again be curtailed 100% and industrial users as much as 20% (in 1980). An optimistic forecast of OCS production would eliminate industrial curtailment In 1985 and 1990 and reduce the utility shortfall to 56% in 1990 and zero in 1985.

Since a National Distribution Scenario requires only that all states share the total U.S. shortfall proportionately by end-use sector, states as well as regions will differ in the total percentage shortfall of supply experienced. Figure IV.24 shows the total percentage shortfall for each of the 9 census division regions under an assumption of national distribution. These results indicate that for a region, where residential and commercial demand are a significant proportion of the total (e.g., over 70% in New England), the percentage shortfall under a National Distribution Scenario will be relatively small. For a region where the bulk of natural gas demand is from industrial users and electric utilities (e.g., 50-60% in the Pacific region and well over 75% in the West South Central), the percentage shortfall will be relatively large.

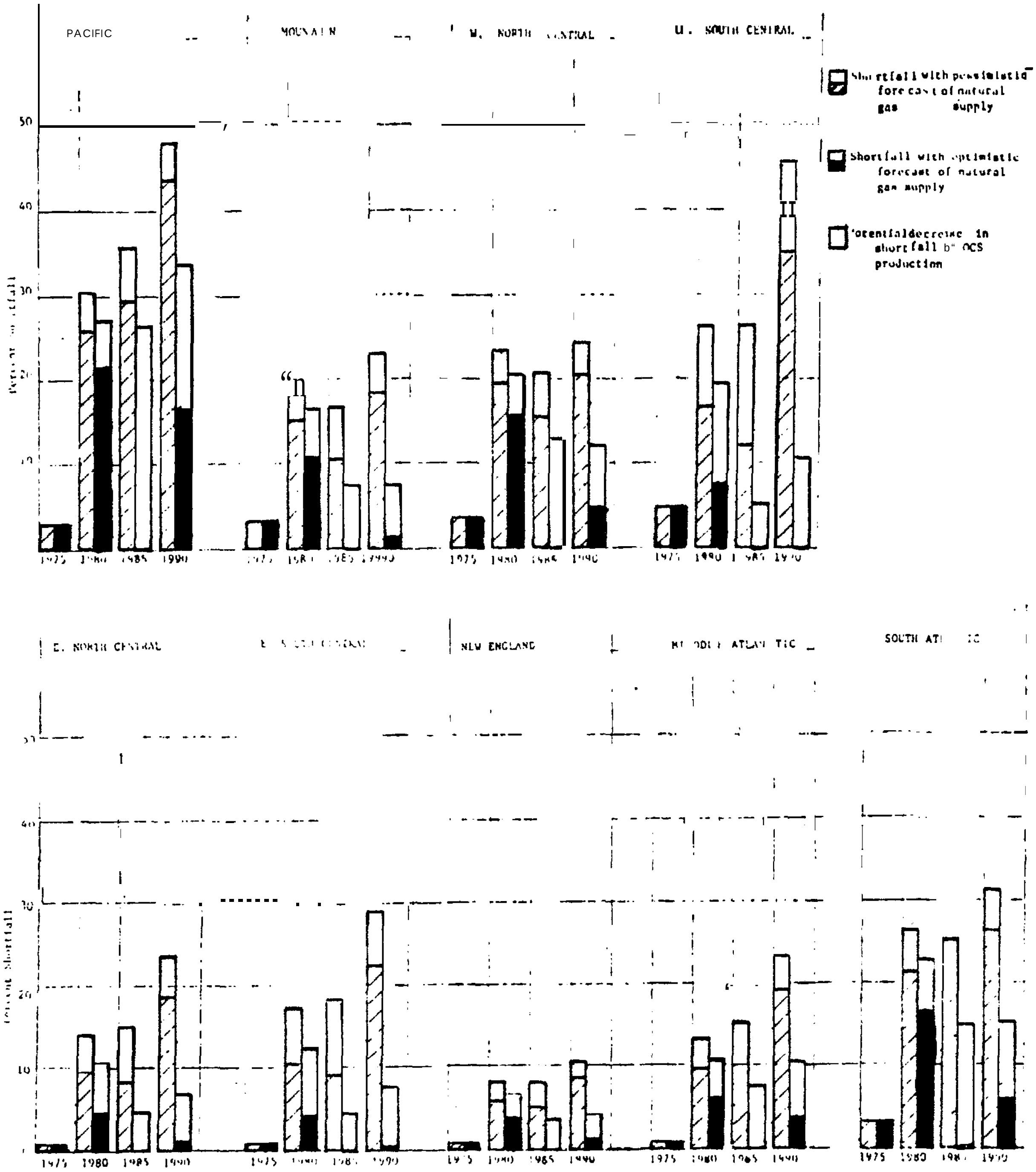
The second distribution scenario assumed that all producing states -- defined here as any state producing at least-two-thirds of its demand from onshore areas - would retain as much of that production needed to satisfy demand. Any surplus in onshore production as well as production from "non-producing" states and OCS areas, imports and other supplemental sources would be distributed nationally. The assumption here was that OCS production would displace traditional sources of natural gas supply, which would be pushed further back in the distribution pipeline. Thus no one region would benefit substantially from geographical proximity to a particular OCS area. Again the FPC curtailment priority schedules were followed in this supply distribution.

Figure IV.25 shows the total U.S. percentage shortfall in supply by end-use sector under this States' Rights with National Distribution Scenario. In contrast to the National Distribution Scenario, regional and state shortfalls by end-use sector are not the same as that of the total Us. In addition, electric utility curtailment does not have to reach 100% before industrial shortages occur (since producing states may satisfy *all* of their electric utility needs even though other states might show substantial industrial shortfalls). Regional shortfalls by end use sector are shown in Figure IV.26 with regions comprised maily of non-producing states showing the largest end-use shortfalls and regions of producing states, such as West South Central which includes Texas and Louisiana, showing little or no shortfalls.

FIGURE IV.23 U. S. Shortfall in Natural Gas Supply by End-Use Sector: National Distribution Scenario

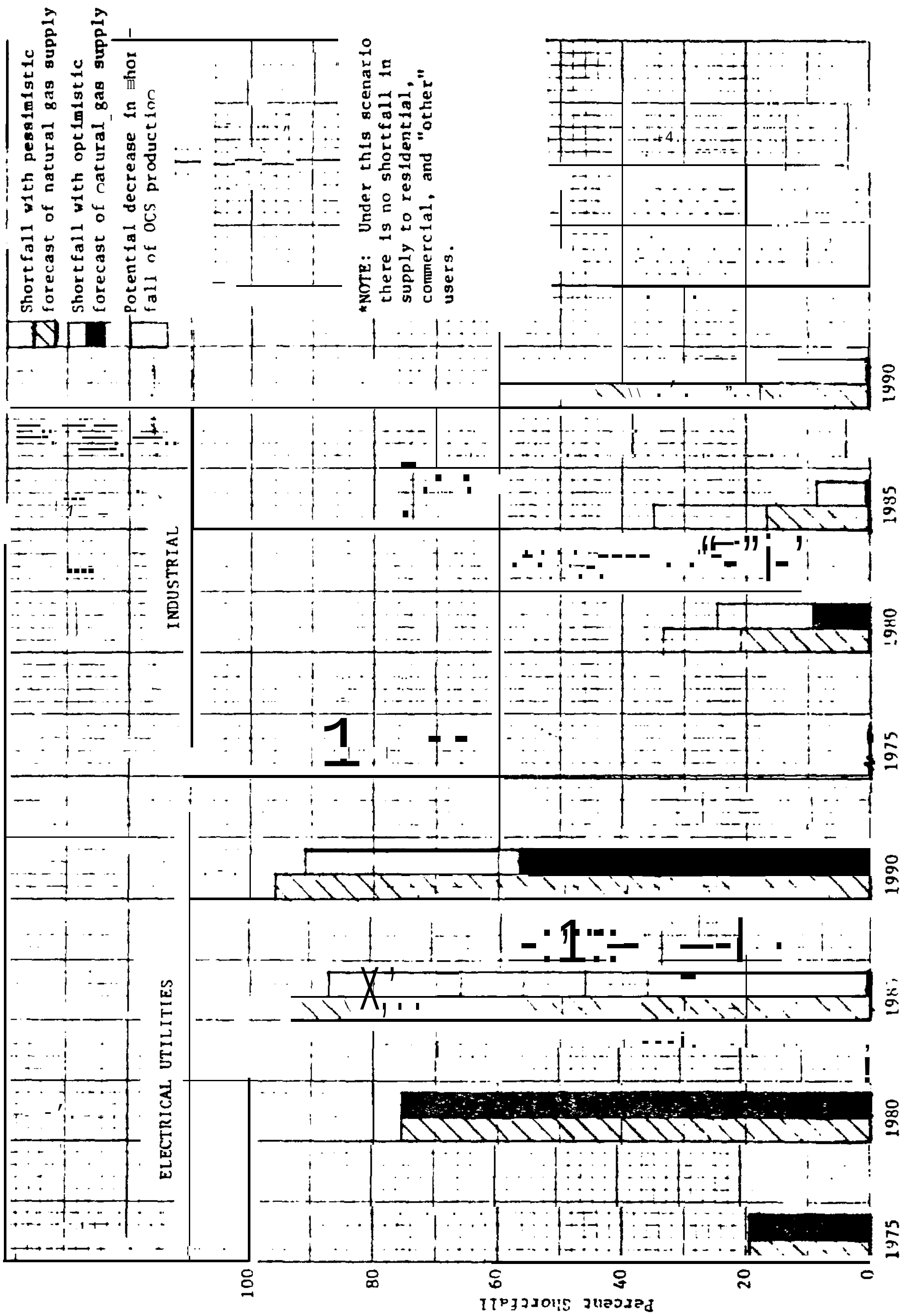


Source: Arthur D. Little, Inc., estimates.



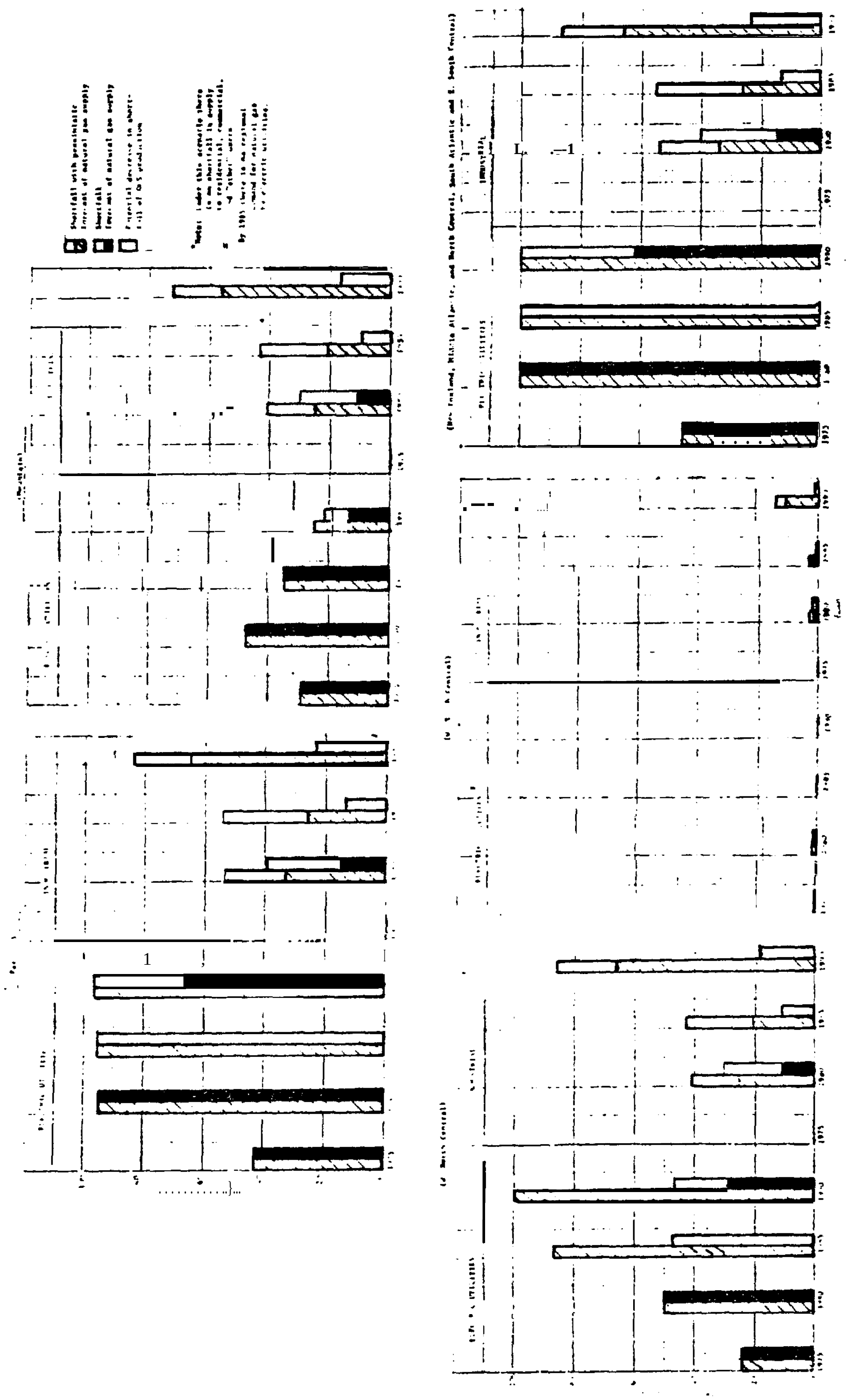
Source: Arthur D. Little, Inc. , estimates.

FIGURE IV.24 Regional Total Shortfalls in Natural Gas Supply: National Distribution Scenario



Source: Arthur D. Little, Inc., estimates.

FIGURE IV.25 Total U. S. Shortfall in Natural Gas Supply by End-Use Sector: States' Rights with National Distribution Scenario



Source: Arthur D. Little, Inc., estimates.

FIGURE IV. 26 Regional Shortfall in Natural Gas Supply by End-Use Sector: States' Rights with National Distribution Scenario

In Figure IV.27 total percentage shortfall is graphed for each census division region. Since OCS and surplus onshore production is shared nationally by priority users, regions such as New England with larger proportions of residential and commercial demand are not penalized for lack of producing states. On the other hand, regions with high proportions of industrial and utility gas requirements may show substantial shortfalls if they lack significant levels of regional onshore production (e.g., Pacific).

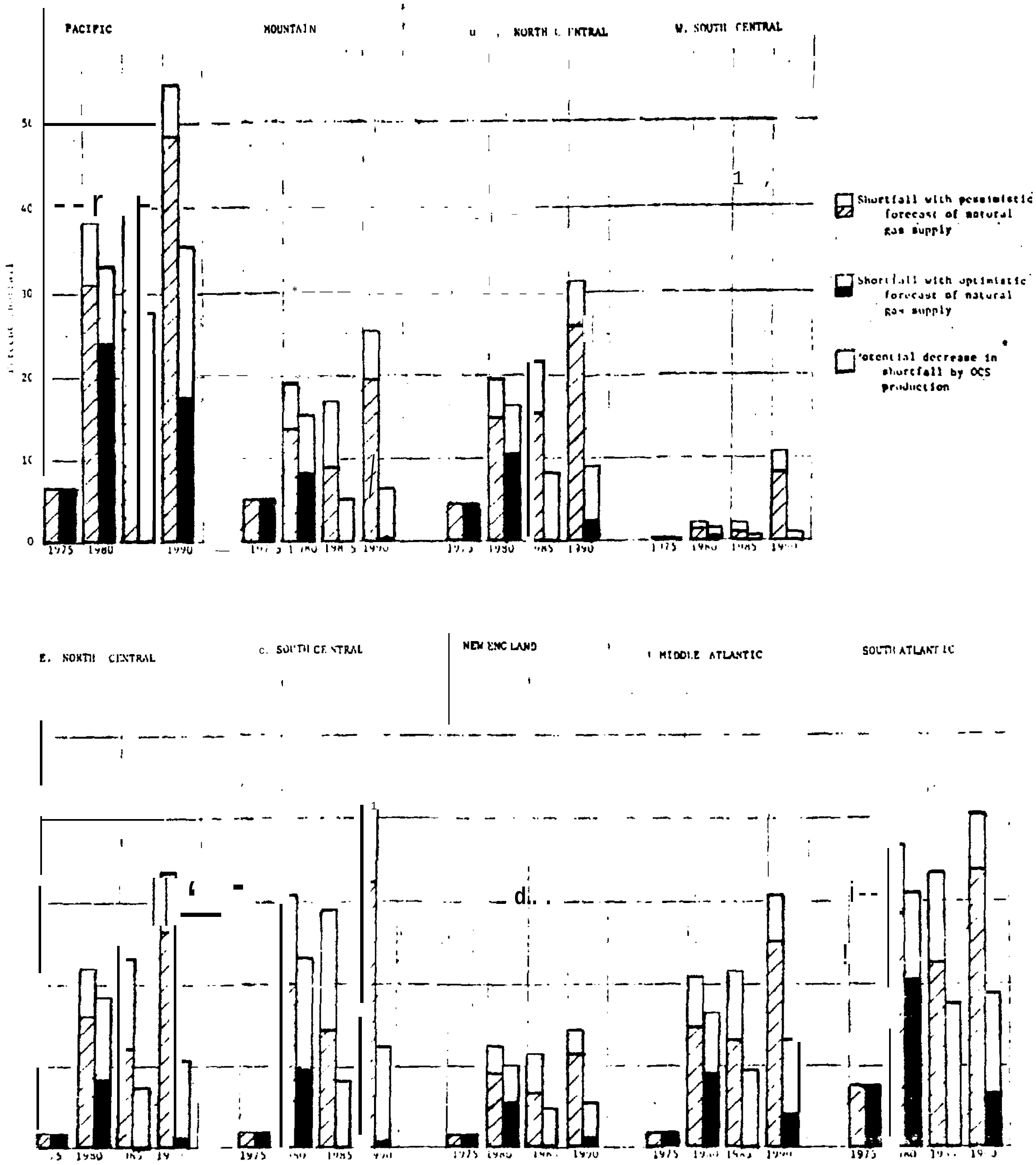
The final scenario assumed again a states' rights position with regard to the onshore production of producing states. Surplus onshore production, OCS production, imports and other sources would then be distributed regionally (i.e., would remain within the census division region of origin) until regional demand was satisfied. Any left over supplies would be allocated nationally to the highest priority users. Under this "States' Rights with Regional Distribution Scenario" it is assumed, therefore, that OCS production will not displace traditional supplies but will supplement existing supplies of the nearest onshore region.

Total U.S. percentage shortfall by end-use sector is shown for the States' Rights with Regional Distribution Scenario in Figure IV.28 Under this scenario total U.S. shortages in the industrial and electric utility categories are reduced relative to the other two scenarios. However this manner of distributing OCS supplies does result in curtailment of higher priority users - "other" and commercial - with a pessimistic forecast of production. End -use sector shortfalls are shown regionally in Figure IV.29 while total shortfall by region is shown in Figure IV.30. As can be expected, this scenario for distribution of supply exacerbates regional differences in supply availability to the greatest degree. On the one hand electric utility requirements may be satisfied fully in the Mountain states while Middle Atlantic commercial users are curtailed.

C. Sensitivity Analyses

Further analyses were conducted to test the sensitivity of the study results to alternative assumptions for two key assumptions made in the supply/demand projections.

The first assumption was that electric utility usage of natural gas in five Gulf Coast States would be reduced by 34.2% per year and phased out completely by 1985 in response to governmental regulation. Based on the 1973 FRC forecast of natural gas consumption, it is estimated that unregulated utility demand for this area could increase approximately 3% per year from 1975 to 1990. Table IV-16 shows the increase in demand that could be expected from this alternative assumption and the resulting impact on total U.S. natural gas shortfall. Statistics from the "base" study are included for comparison. With this higher level of demand, the total U.S. shortfall increases considerably



Source: Arthur D. Little, Inc. , estimates.

FIGURE IV. 27 Regional Total Shortf ails in Natural Gas Supply: States' Rights with National Distribution Scenario

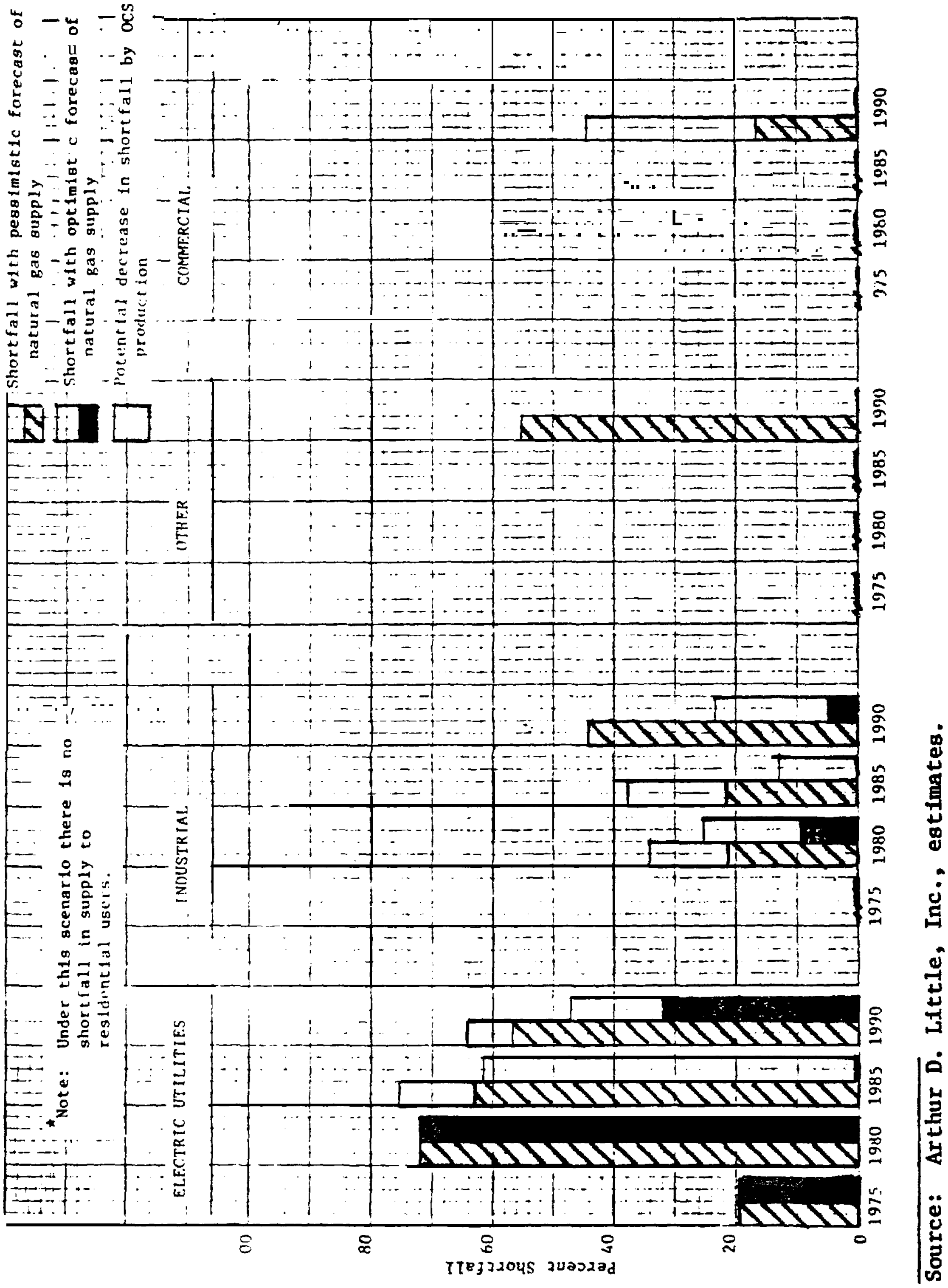


FIGURE IV. 28 Total U. S. Shortfalls in Natural Gas Supply by End-Use Sector: States' Rights with Regional Distribution Scenario

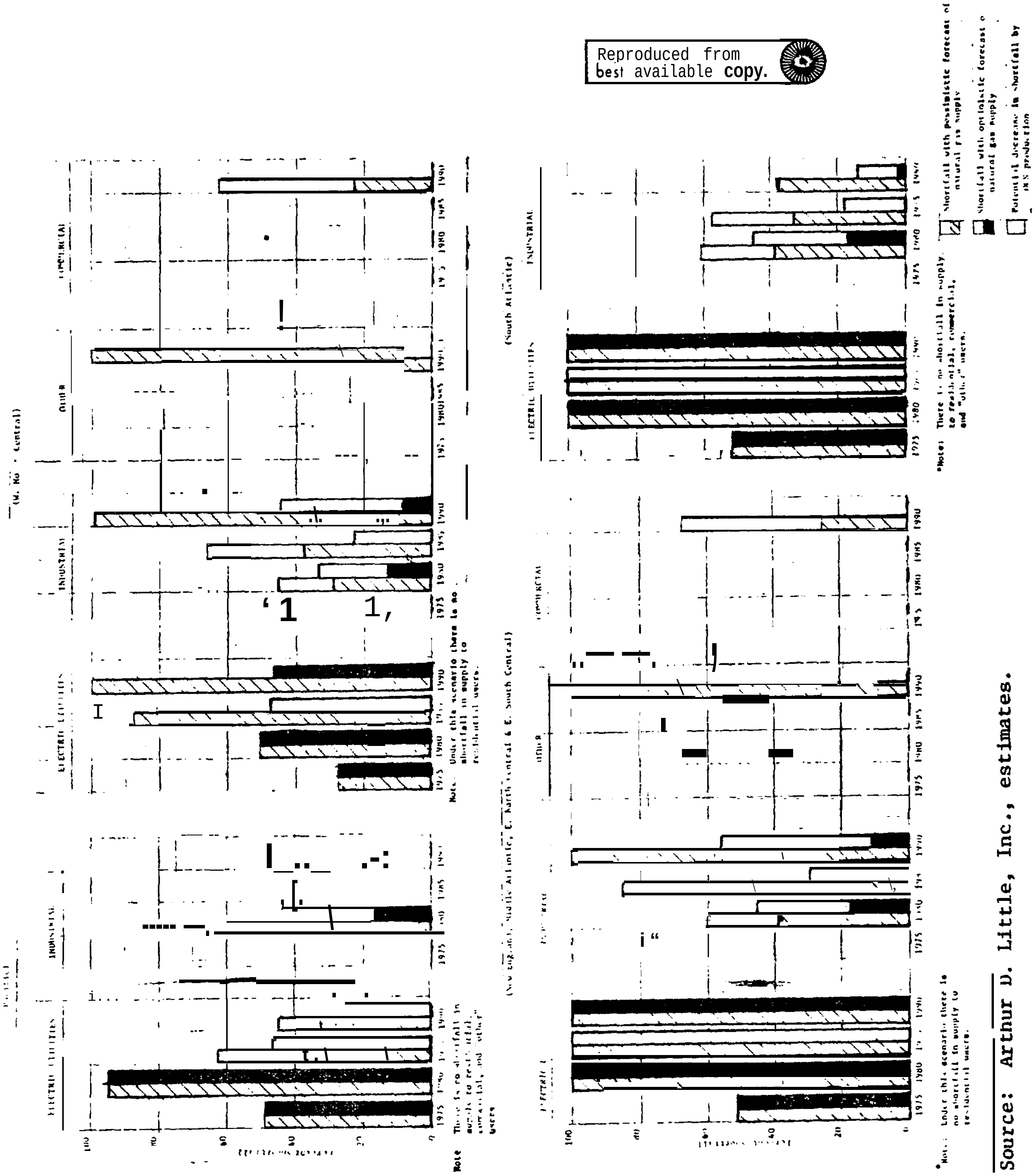
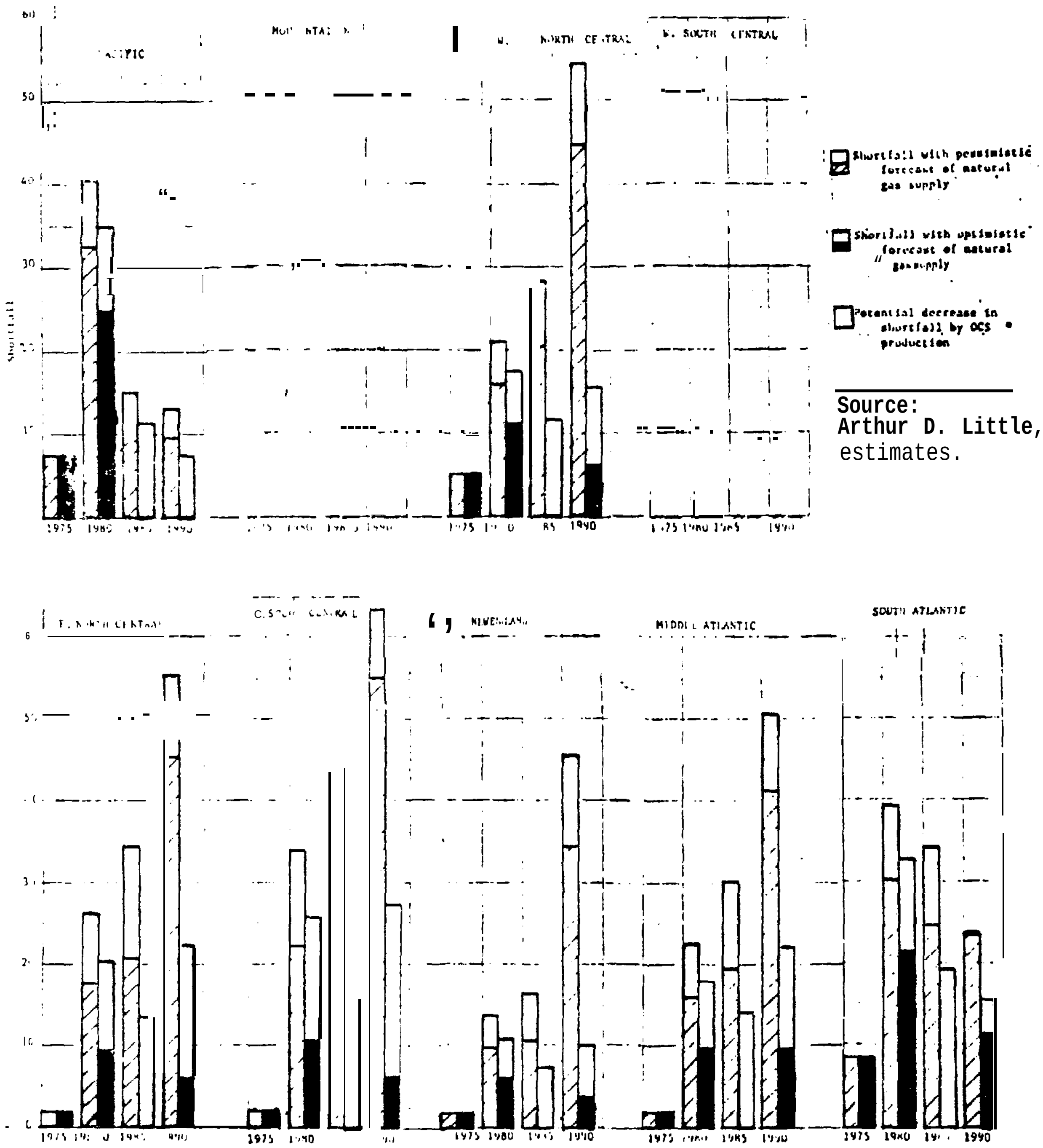


FIGURE IV. 29 Regional Shortfall in Natural Gas Supply by End-Use Sector: States' Rights with Regional Distribution Scenario



Source:
Arthur D. Little, Inc. ,
estimates.

FIGURE IV. 30 Regional Total Shortfalls in Natural Gas supply : States' Rights with Regional Distribution Scenario

TABLE IV-16

TOTAL U.S. SHORTFALL OF NATURAL GAS SUPPLY WITH HIGHER ESTIMATES OF UTILITY DEMAND[1]

	1975		1980		1985		1990	
Base Study Demand (TCF)	18.57		18.74		20.49		23.08	
Increase due to higher electric utility demand (TCF)	.72		2.25		2.86		3.42	
Revised demand estimates (TCF)	19.29		20.99		23.35		26.50	
Percentage Shortfall:	Base Study	Revised Demand	Base Study	Revised Demand	Base Study	Revised Demand	Base Study	Revised Demand
- Pessimistic Base Case	2.8	6.4	21.2	29.7	21.9	31.4	32.1	40.9
- Pessimistic Case with OCS	2.8	6.4	15.5	24.6	13.9	24.5	26.5	36.0
- Optimistic Base Case	2.8	6.4	17.2	26.1	10.0	21.1	13.3	34.5
- Optimistic Case with OCS	2.8	6.4	10.0	19.7	0	10.3	4.4	16.7

[1] "Base Study" assumes that electric utility usage of natural gas in the five Gulf Coast states will be reduced by 34.2% per year and phased out completely by 1985.

"Revised Demand" assumes that utility demand will increase at approximately 3% per year from 1975 to 1990.

Source: Arthur D. Little, Inc., estimates.

relative to the base study shortfalls. Under pessimistic forecast of supply excluding OCS production the 1990 shortfall increases from 32% to 41%. With OCS production the shortfall increases from 27% in the base demand study to 36% with higher demand. Under an optimistic forecast of supply, the 1990 shortfall is 25% without OCS production and 17% with OCS production, compared to 13% and 4%, respectively, in the base study.

A second sensitivity analysis examined the assumptions that Arctic gas will be available for import by 1985 and that coal gasification will progress significantly beyond a demonstration-plant phase by 198S. In an alternative assumption the 1980 levels of these sources will be maintained through 1990, total adjusted supply to consumers is decreased by 1.6 TCF in 1985 and 2.1 TCF in 1990. The resulting impact on total U.S. shortfall is shown in Table IV-17.

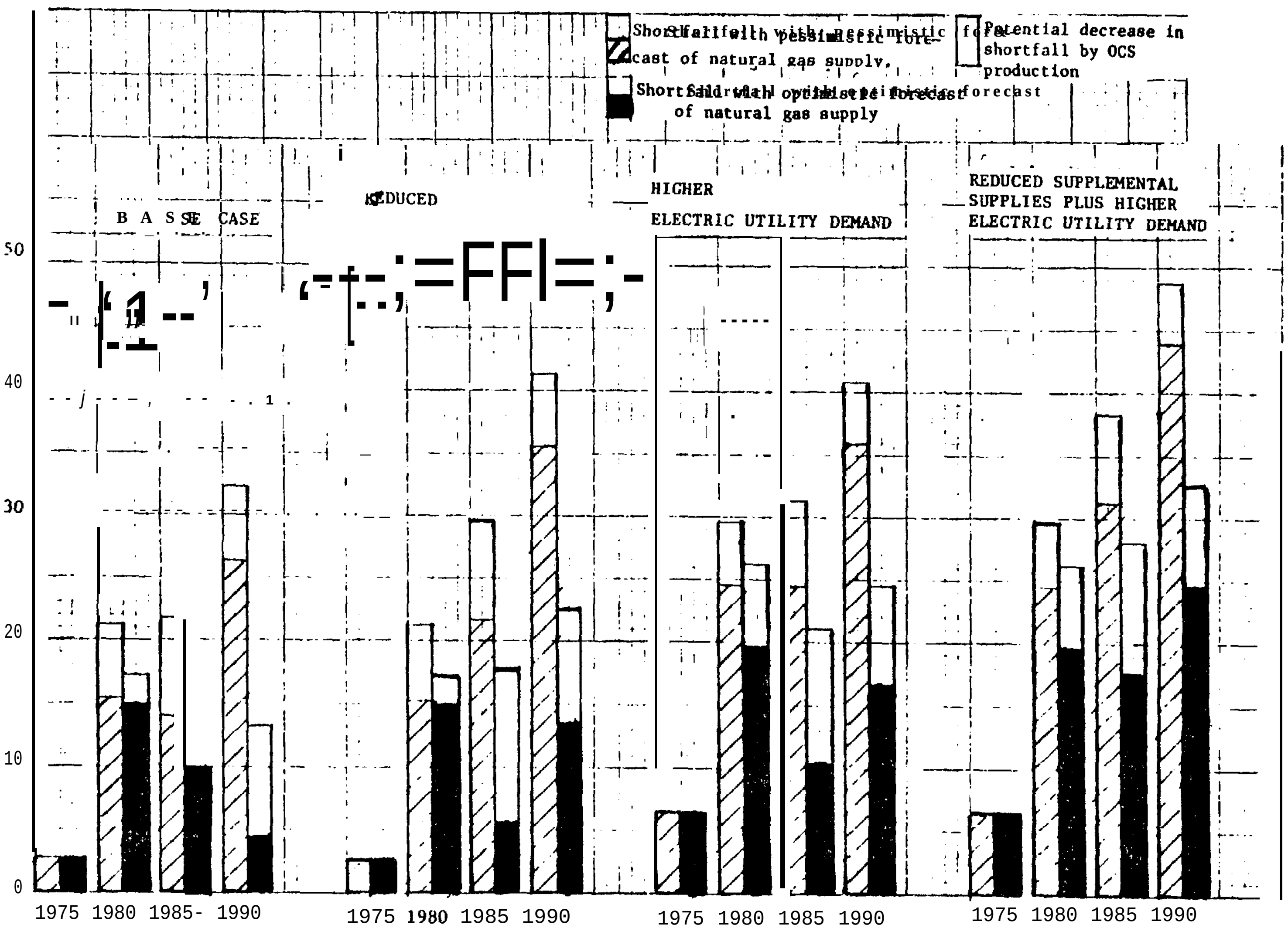
The results of these sensitivity analyses, as well as the shortfall that would be expected if both higher demand and lower supplies were to prevail, are graphed in Figure IV.31 along with the base study percentage shortfalls for comparison. Relative to the 1990 base study results, assuming a pessimistic supply forecast and no OCS production (32% shortfall), total U.S. shortfall increases to 41% under either lower supply or higher demand estimates and to 49% with both lower supplies and higher demand. OCS production could decrease these shortfalls to 36% in the case of either lower supply or higher demand and to 44% of both higher demand and lower supply are assumed. With optimistic forecasts of domestic supply, there is a 33% shortfall in 1990 (no OCS production) under a higher demand plus lower supply assumption compared with only a 13% base study shortfall. With OCS production the shortfalls decrease to 24% and 4%, respectively.

D. CAPITAL REQUIREMENTS

The capital expenditures which are required for exploration and development of each OCS area were determined as a part of the cost and production projections. These expected annual and cumulative capital expenditure projections for the various OCS areas are summarized in Table IV-18 for four different oil and gas price levels. The price levels are for oil and gas, respectively: (1) $4.50/bbl, $0.75/MCF; (2) $7.50/bbl, $1.25/MCF; (3) $12.00/bbl, $2.00/MCF; and (4) $18.00/bbl, $3.00/MCF. As the prices increase, smaller fields are developed and the increases in capital expenditures with increasing prices reflect the additional field developments. The capital requirement projections explicitly exclude lease costs to the Federal Government, these lease costs have historically represented a significant portion of the total costs of developing a field.

The annual capital expenditures are expected to reach a maximum around 1980 followed by rapid decline as fields are completed to about 10% of the 1980 expenditure in 1985 and still less in 1990. Considering the price scenario of $12.00/bbl for oil and $2.00/MCF for gas in Table IV-18, the total expected capital requirements for all OCS areas

FIGURE IV.31 Total U. S. Shortfall in Natural Gas Supply - Sensitivity Analyses



Source: Arthur D. Little, Inc. , estimates.

TABLE IV-17

TOTAL U.S. SHORTFALL OF NATURAL GAS SUPPLY
WITH LOWER ESTIMATES OF SUPPLEMENTAL SOURCES[1]

	1985		1990	
Decrease in Supply Relative to Ease Study	1,611.08		2,111.08	
Revised Estimates of Supply				
Pessimistic Base Case	14,399.65		13,560.17	
Pessimistic Case with OCS	16,030.69		14,865.82	
- Optimistic Base Case	16,824.57		17,895.13	
- Optimistic Case with OCS	19,328.17		19,963.01	
Percentage Shortfall	Base Study	Revised Supply	Base Study	Revised Supply
- Pessimistic Base Case	21.9	29.7	32.1	41.3
- Pessimistic Case with OCS	13.9	21.8	26.5	35.6
- Optimistic Base Case	10.0	17.0	13.3	22.5
- Optimistic Base Case	0	5.7	4.4	13.5

[1]Supplemental supplies from coal gasification and from Arctic gas sources will, through 1990, remain at the same low levels as assumed for 1980.

Source: Arthur D. Little, Inc., estimates.

TABLE IV-18

ANNUAL AND CUMULATIVE CAPITAL EXPENDITURES FOR OIL AND GAS PRODUCTION IN OCS AREAS
($ millions)

	$4.50/Bbl - $0.75/MCF				$7.50/Bbl - $1.25 MCF				$12.00/Bbl - $2.00/MCF				$18.00/Bbl - $3.00/MCF			
	1980	1985	1990	Cum. Thru 1990	1980	1985	1990	Cum. Thru 1990	1980	1985	1990	Cum. Thru 1990	1980	1985	1990	Cum. Thru 1990
N. Atlantic	46'.65	0	0	272.46	92.10	0	0	480.58	116.13	0	0	576.48	118.60	0	0	584.94
Mid Atlantic	82.68	0	0	474.93	136.02	0	0	755.45	161.61	0	0	852.08	164.06	0	0	860.92
S. Atlantic	10.49	0	0	42.93	52.47	0	0	228.29	68.28	0	0	304.46	69.64	0	0	309.88
Total	139.81	0	0	790.32	280.58	0	0	1464.32	346.01	0	0	1733.00	352.30	0	0	1755.73
Gulf of Mexico																
E. Gulf MAFLA	32.16	8.01	1.32	334.71	53.52	8.01	1.32	810.14	53.52	8.01	1. '12	830.90	53.52	8.01	1.32	831.26
Cent. & West Gulf	337.41	51.52	17.91	2199.62	700.75	64.19	17.91	3814.51	741.84	65.44	17.91	3978.64	742.01	65.44	17.91	3979.89
Total	369.57	59.54	19.23	2534.33	754.27	72.20	19.23	4624.66	795.36	73.45	19.23	4809.54	795.53	73.45	19.23	4811.15
Pacific OCS																
S. California	133.03	0	0	882.36	230.30	.11	0	1432.91	260.62	.11	0	1567.96	270.17	.11	0	1602.65
Washing. /Oregon	55.54	0	0	161.66	145.91	0	0	413.47	169.83	0	0	500.90	174.72	0	0	517.81
Total	188.57	0	0	1044.02	376.21	.11	0	1846.37	.430.44	.11	o	2068.86	444.90	.11	0	2120.46
Alaska OCS																
GOA East	--	--	--	--	118.55	.98	0	582.95	192.66	.98	0	923.73	216.95	.98	0	1070.67
GOA Kodiak	--	--	--	--	30.68	.08	0	142.58	60.72	.08	0	286.22	70.56	.08	0	348.26
GOA S. Aleutian	--	--	--	--	--	--	--	--	1.37	2.63	0	19.12	5.33	4.89	0	51.24
Lower Cook Inlet	44.18	.48	a	130.32	201.35	.7'3	0	731.80	251.17	.79	0	983.46	311.69	.19	0	1157.63
Bristol Basin	--	--	--	--	34.85	21.96	0	333.64	55.88	26.94	0	466.53	66.70	28.92	0	584.37
Bering Sea-Norton	--	--	--	--	3?.02	8.52	0	246.53	57.16	11.05	0	389.37	66.22	11.84	0	453.13
Bering-St. George	--	--	--	--	116.26	1.74	0	479.87	139.93	1.74	0	626.86	181.59	1.74	0	840.87
Chukchi Sea	--	--	--	--	2.37	0	0	12.34	4.62	10.87	0	64.69	11.58	17.24	0	125.07
Beaufort Sea	--	--	--	--	276.19	14.99	.23	1008.33	338.42	14.99	.23	1401.83	419.50	16.10	.23	1692.90
Total	4.4.18	.48	0	130.32	817.26	49.06	.23	3538.04	1121.93	70.07	.23	5161.73	1350.13	82.58	.23	6324.12
Grand Total	742.13	60.02	19.23	4498.98	2228.32	121.37	19.47	11473.38	2693.75	143.63	19.47	13773.18	2942.86	156.14	19.47	15101.47

Scarce: Arthur D. Little, Inc., estimates.

in 1980 are $2.7 billion, in 1985 $144 million, and in 1990 $19 million with a cumulated required investment from the present through 1990 of $13.8 billion (in 1975 dollars). The annual capital expenditures appear significant compared to the capacity of the oil and gas industry for capital generation for exploration and development. It can be estimated that the oil and gas industry invested about $4 billion in 1974 for exploration and development. Hence, it must be concluded that the development of the OCS will require a significant effort for the oil and gas industry during the peak years around 1980. If the prices increase, to $18.00/bbl for oil and $3.00/MCF for gas, only small additional investments will be required in 1980 with an increase from $2.7 billion to $2.9 billion in the capital requirements. The breakdown of expenditures is described above in Section IV-A-2.

The cumulated capital requirements for the period through 1990 total $13.8 billion (under the $12.00/bbl and $2.00 MCF price scenario). Compared to the total capital market, this amount appears very small and corresponds to less than .01% of the total GNP over the period. When compared to other expected energy related investments which have been estimated to be about one trillion dollars through 1990, the OCS development also appears reasonably small.

The total capital investment which will be required for exploration and development of the OCS is very uncertain and will vary extensively with the amount of oil and gas which will be located. If the amounts of oil and gas which are found are small, exploration will be pursued less vigorously and perhaps be terminated early and small development costs will be required. If the amounts found are large, the development activities which will be required are also large. Figure IV.32 presents the uncertainties for the six consolidated OCS areas. For each area, the capital which will be required for exploration and development, may vary extensively for different levels of confidence. Hence, for the Atlantic Coast, the likelihood is 95% that the capital requirements will be at most $0.5 billion; 75% likelihood that it will be $1.1 billion or less; 50% likelihood that it will be $1.7 billion or less; 25% likelihood that it will be $2.4 billion; and 5% likelihood that it will be at most $4.2 billion, Between the confidence levels of 75% and 25% (which accounts for 50% of the expectations), the total capital expenditures for the Atlantic Coast increase from at most $1.1 billion to $2.4 billion, a range of 1 to 2.18. For the other OCS areas the uncertainties vary similarly as indicated in Figure IV.32.

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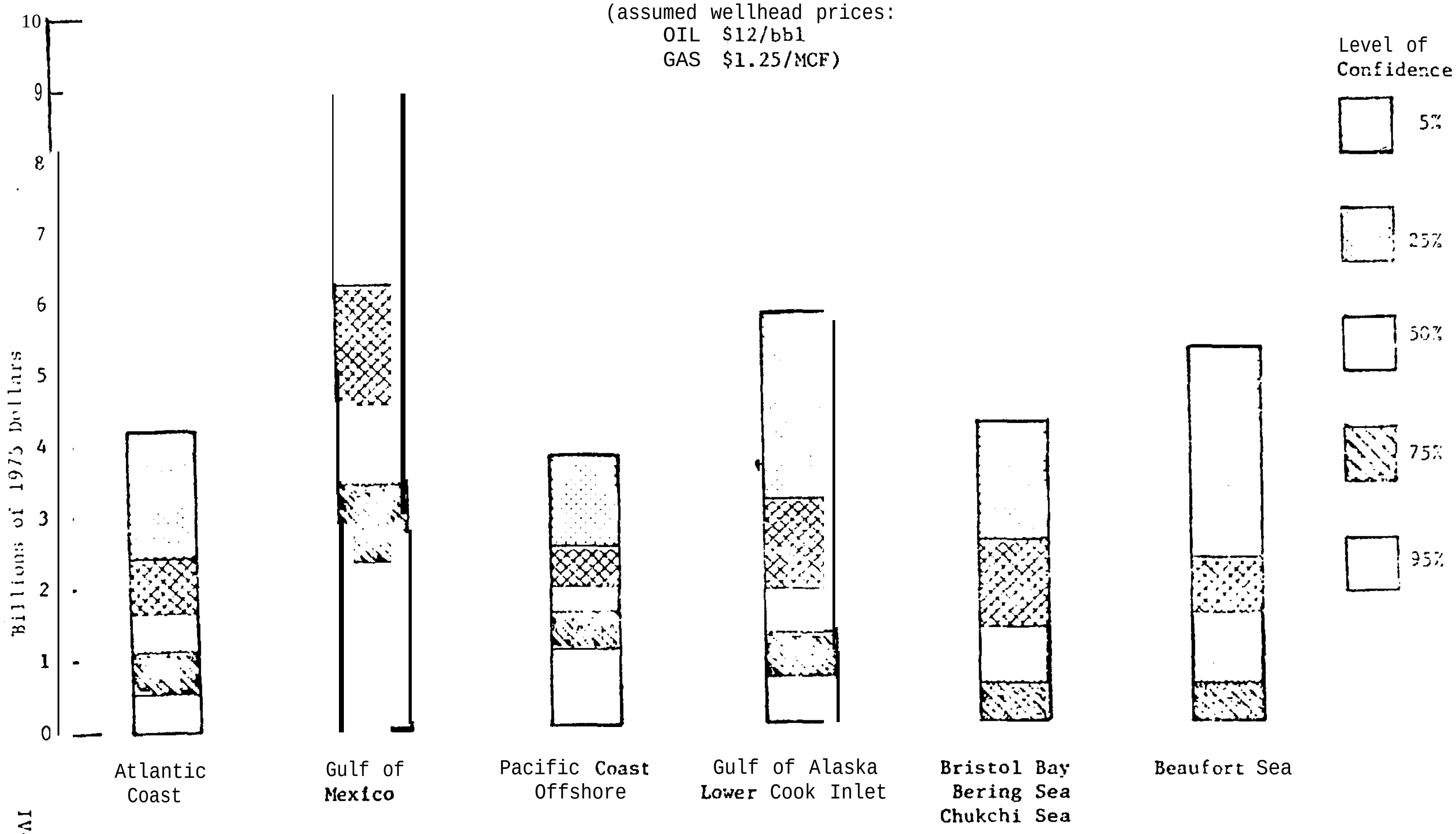
*Capital Needs and Policy Choices in the Energy Industries. Report submitted to the Federal Energy Administration, October 1974 by Arthur D. Little, Inc. (C-77389).

FIGURE IV.32

Estimates of Required Total Capital Expenditures At Different Confidence Levels For Exploration Drilling and Field Development in Areas Leased or to be Leased through 1978 on the Outer Continental Shelf of the U.S.

(assumed wellhead prices:
OIL $12/bbl
GAS $1.25/MCF)



Source: Arthur D. Little, Inc., estimates.

APPENDIX A

RESOURCE DISTRIBUTIONS FOR OIL AND GAS BY OCS AREA

RESOURCE BASE SIZE DISTRIBUTION GAS;
IN TRILLIONS OF CFT OF RECOVERABLE RESERVES

	Cumulative Percentiles									
	0.	1.	5.	25.	50.	75.	95.	99.	100.	F (Dry)
1. North Atlantic	o.	2.4	3.0	5.0	6.8	9.0	15.0	20.0	30.0	0.40
2. Mid Atlantic	0.	2.4	3.0	5.0	6.5	9.0	15.0	21.0	30.0	0.30
3. South Atlantic	0.	0.6	0.8	1.2	1.6	2.0	3.0	4.0	5.4	0.60
4. Eastern Gulf	0.	0.35	0.5	0.85	1.25	1.8	3.0	4.4	6.5	0.30
5. Central Western Gulf	0.	12.5	17.0	28.0	38.0	55.0	92.0	125.0	175.0	0.0
6. So. California	0.0	1.075	1.438	2.043	2.573	3.330	4.661	5.838	6.5	0.0
6A. Santa Barbara										
7. Wash., Oregon & No. California	0.0	0.0	0.0	0.201	.430	.883	2.412	3.421	5.0	0.40
8. Gulf of Alaska, East	0.0	0.1	0.6	1.5	3.0	6.0	15.0	29.0	5.0	0.30
9. Gulf of Alaska Kodiak	0.0	0.06	0.12	0.45	1.0	2.0	6.0	13.5	30.0	0.60
10. Gulf of Alaska, Aleutian Shelf	0.0	0.07	0.16	0.20	0.30	0.5	1.0	1.6	2.5	0.80
11. Lower Cook Inlet	0.0	0.8	1.0	1.6	2.2	3.0	4.5	6.3	8.4	0.0
12. Outer Bristol Basin	0.0	0.2	1.6	2.25	3.0	4.0	6.0	8.0	11.0	0.50
13. Bering Sea (Norton Basin)	0.0	0.4	0.5	0.9	1.2	1.8	3.0	4.3	6.5	0.40
14. Bering Sea (St. George)	0.0	1.5	2.0	3.8	5.5	8.2	15.0	23.0	35.0	0.50
15. Chukchi Sea (Hope Basin)	0.0	0.4	0.5	0.9	1.2	1.8	3.0	4.3	6.5	0.40
16. Beaufort Sea	0.0	4.0	5.0	7.5	10.0	13.5	20.0	20.5	35.0	0.25

RESOURCE BASE SIZE DISTRIBUTION OIL;
IN BILLIONS OF BBLS. RECOVERABLE RESERVES

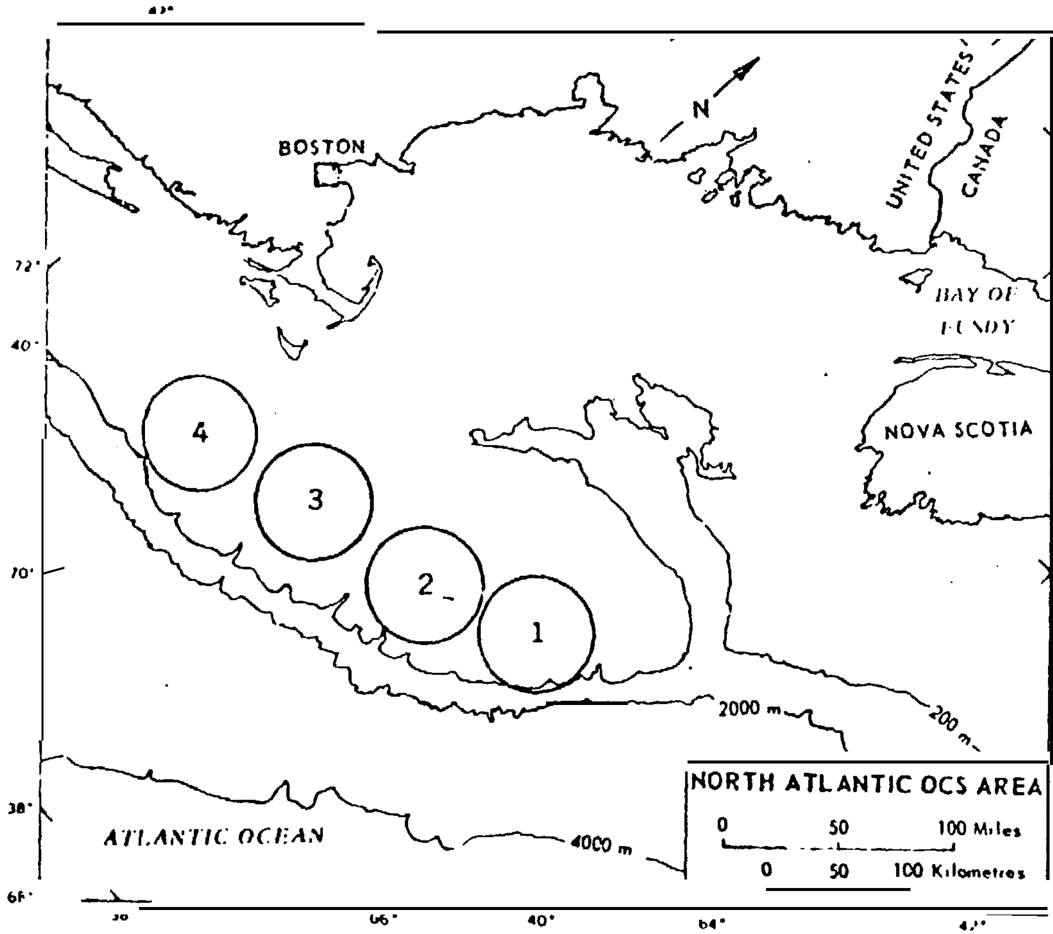
		Cumulative Percentiles									
		0.	1.	5.	25.	50.	75.	95.	99.	100.	P (Dry)
1.	North Atlantic	0.	0.4	0.6	1.0	1.35	1.8	3.0	4.0	6.0	?.40
2.	Mid Atlantic	0.	0.8	1.0	1.67	2.2	3.0	5.0	7.0	10.0	0.30
3.	South Atlantic	0.	0.3	0.4	0.6	0.8	1.0	1.5	2.0	2.7	0.60
4.	Eastern Gulf	0.	0.35	0.5	0.85	1.25	1.8	3.0	4.4	6.5	0.30
5.	Central Western Gulf	0.	1.8	2.0	2.8	3.6	4.6	6.4	8.3	13.0	0.0
6.	So. California	0.0	1.047	1.357	1.931	2.464	3.114	4.384	5.465	6.0	0.0
6A.	Santa Barbara }										
7.	Wash. Oregon & No. California	0.0	0.0	0.	0.223	0.451	0.751	1.311	1.795	2.0	0.40
8.	Gulf of Alaska, East	0.0	0.1	0.2	0.5	1.0	2.0	5.0	10.0	20.0	0.30
9.	Gulf of Alaska Kodrak	0.0	0.02	0.04	0.15	0.33	0.67	2.0	4.5	10.0	0.60
10.	Gulf of Alaska Aleutian Gulf	0.0	0.03	0.05	0.10	0.16	0.25	0.5	0.8	1.3	0.90
11.	Lower Cook Inlet	0.0	0.4	0.5	0.8	1.1	1.5	2.25	3.15	4.2	0.0
12.	Outer Bristol Basin	0.0	0.2	0.5	0.8	1.25	1.75	3.0	4.2	7.0	0.50
13.	Bering Sea (Morton Basin)	0.0	0.4	0.5	0.8	1.2	1.75	2.8	4.0	6.0	0.60
14.	Bering Sea (St. George)	0.0	0.6	0.8	1.5	2.25	3.3	6.0	9.0	15.0	0.50
15.	Chukchi Sea (Hope Basin)	0.0	0.15	0.20	0.3	0.4	0.53	0.8	1.05	1.5	0.70
16.	Beaufort Sea	0.0	1.6	2.0	3.0	4.0	5.5	8.0	10.6	14.0	0.25

APPENDIX B

MAPS OF INDIVIDUAL OC S AREAS WITH INDICATIONS OF HYPOTHETICAL DRILLING SIZES IN ACCELERATED OCS LEASING PROGRAM*

*Source: Final Environmental Statement. Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf

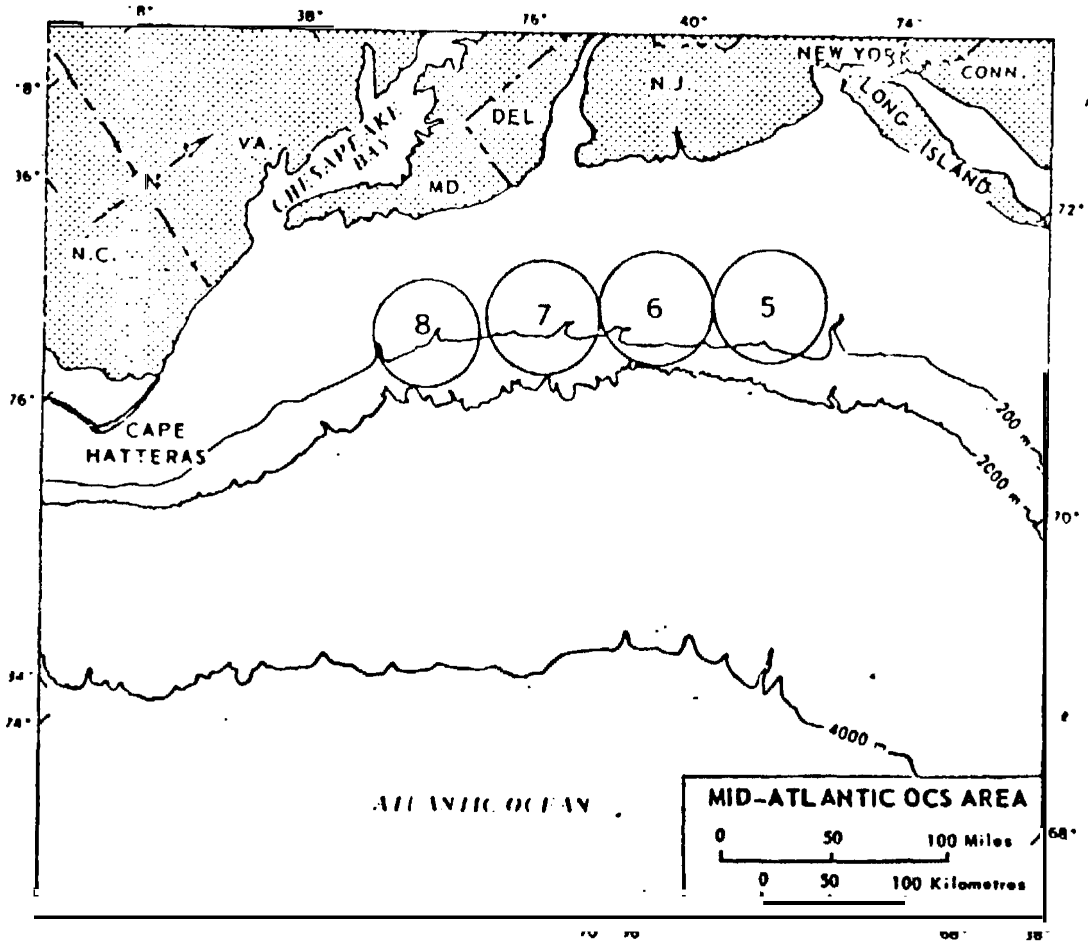
FES 75 United States Department of the Interior.



HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM

1. 41° 10' N, 66° 50' W
2. 40° 50' N, 67° 50' W
3. 40° 40' N, 69° 00' W
4. 40° 25' N, 70° 00' W

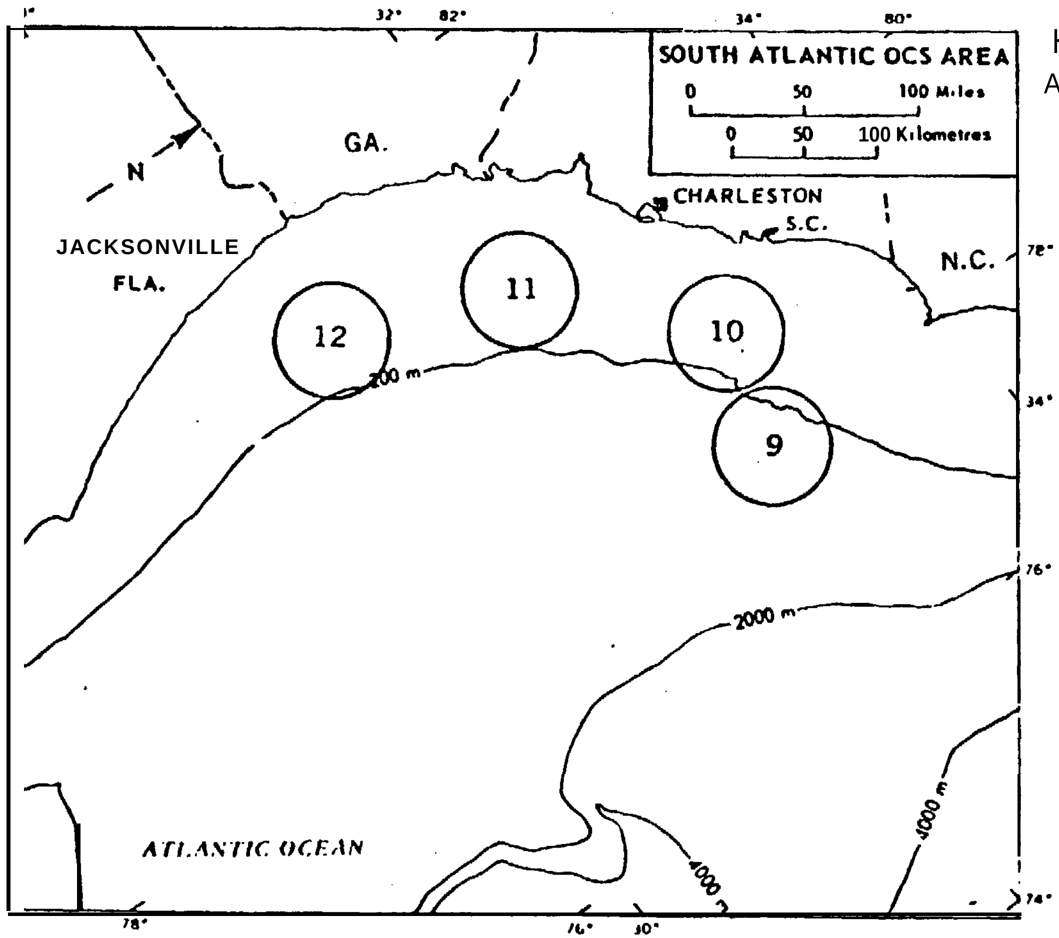
FIGURE 1



HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM

5	39° 15' N 72° 50' W
6	38° 35' N 73° 28' W
7	38° 00' N 74° 00' W
8	37° 20' N 74° 30' W

FIGURE 2



HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM

9 32"30' N 77°55' W

10 32° 40' N 78"59' W

11 31°30" N 80° 00' W

12 30° 30' N 80° 30' W

FIGURE 3

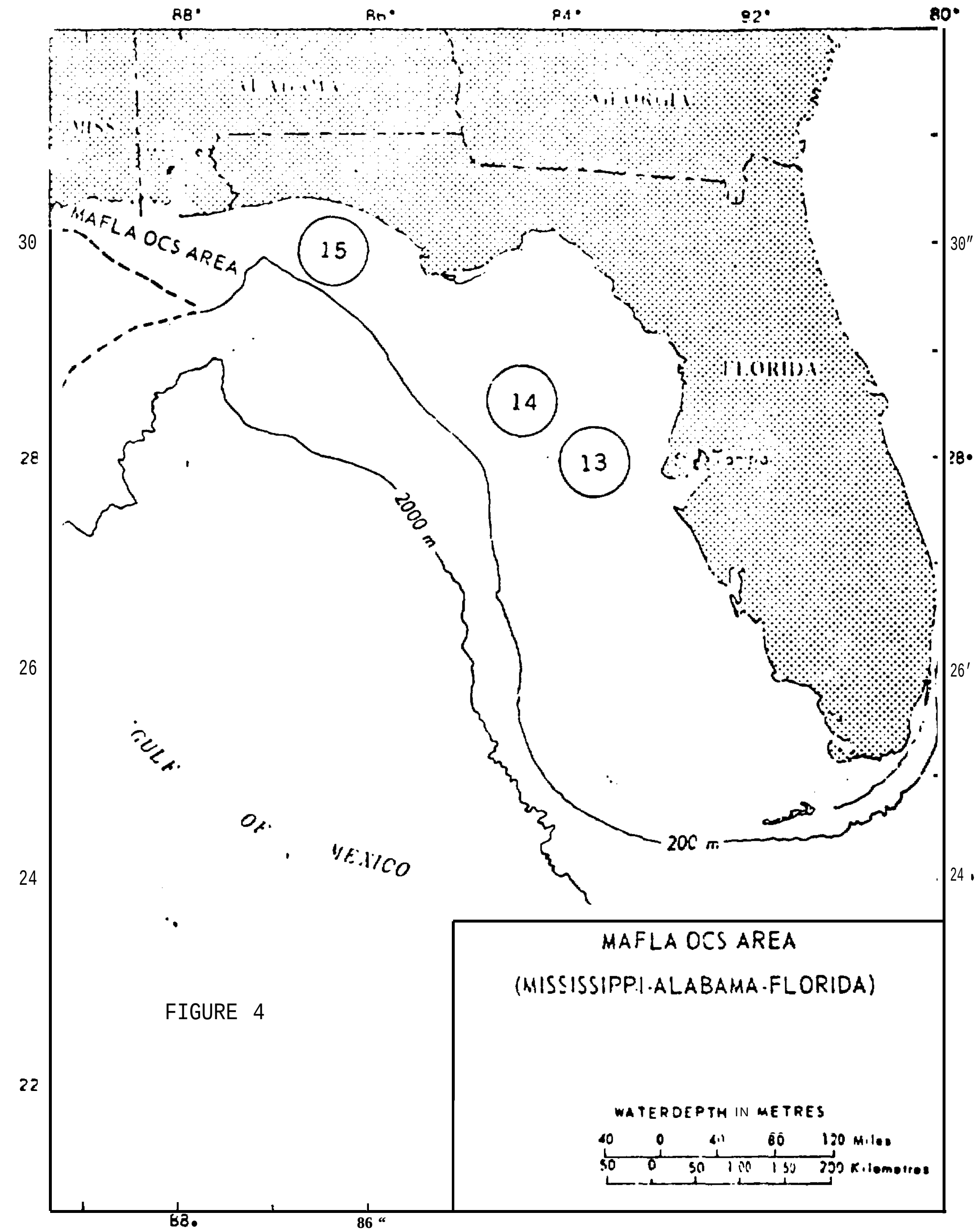


FIGURE 4

HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM

13 27°55′ N 82°40′ W

14 28°30′ N 84°25′ W

15 29°55′ N 86°25′ W

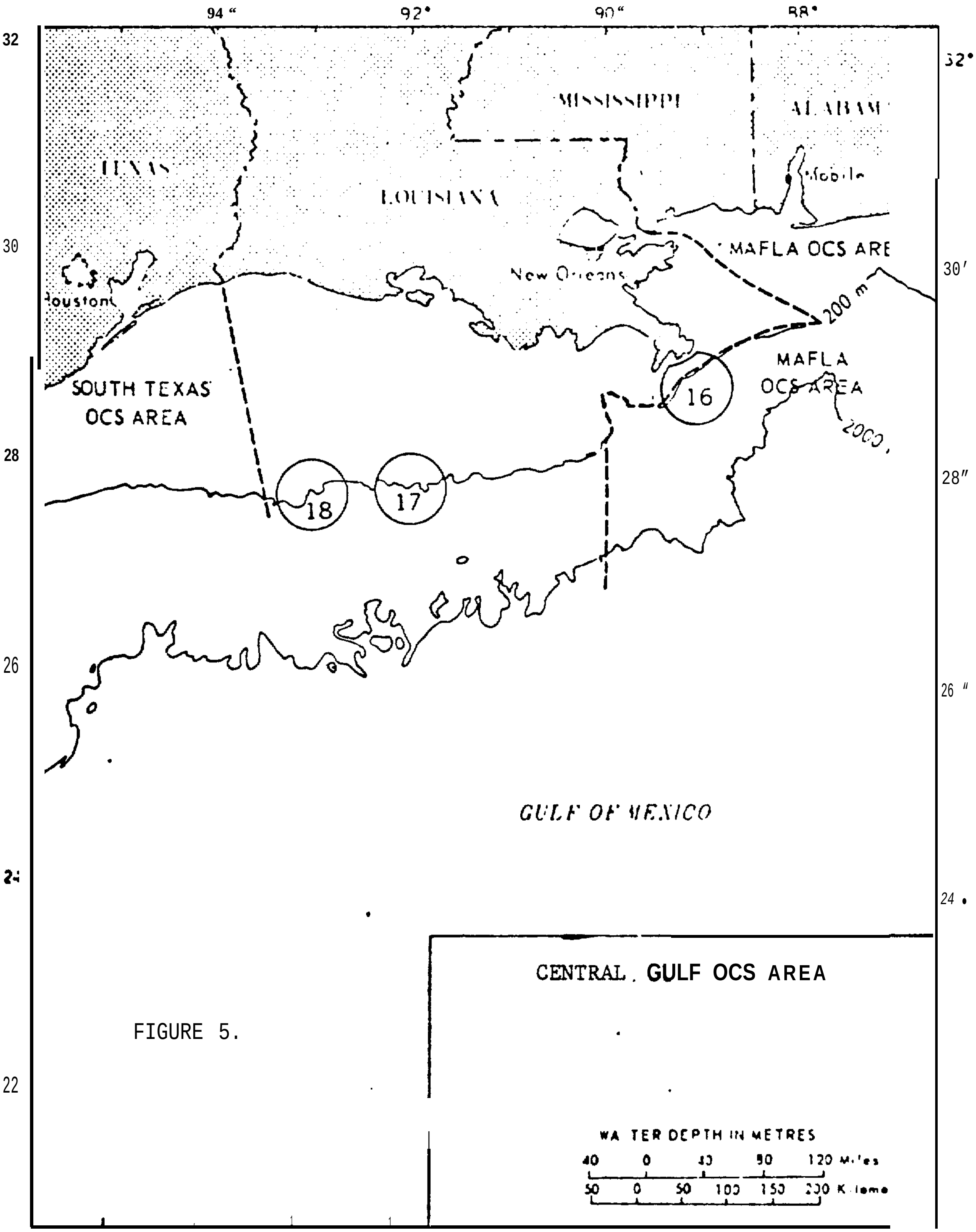


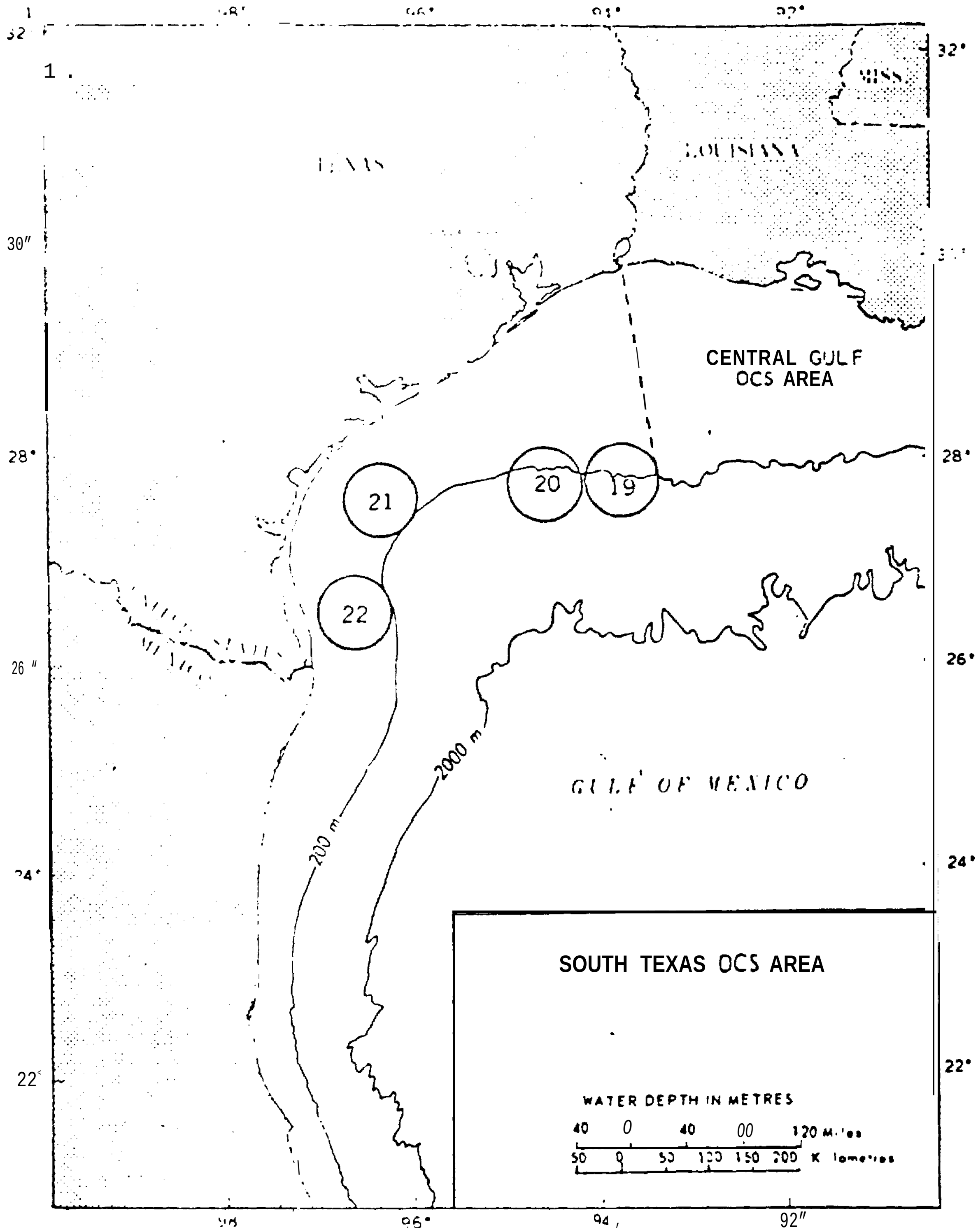
FIGURE 5.

HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM

16 29°45″ N 89°00′ W

17 27°50′ N 92°00′ W

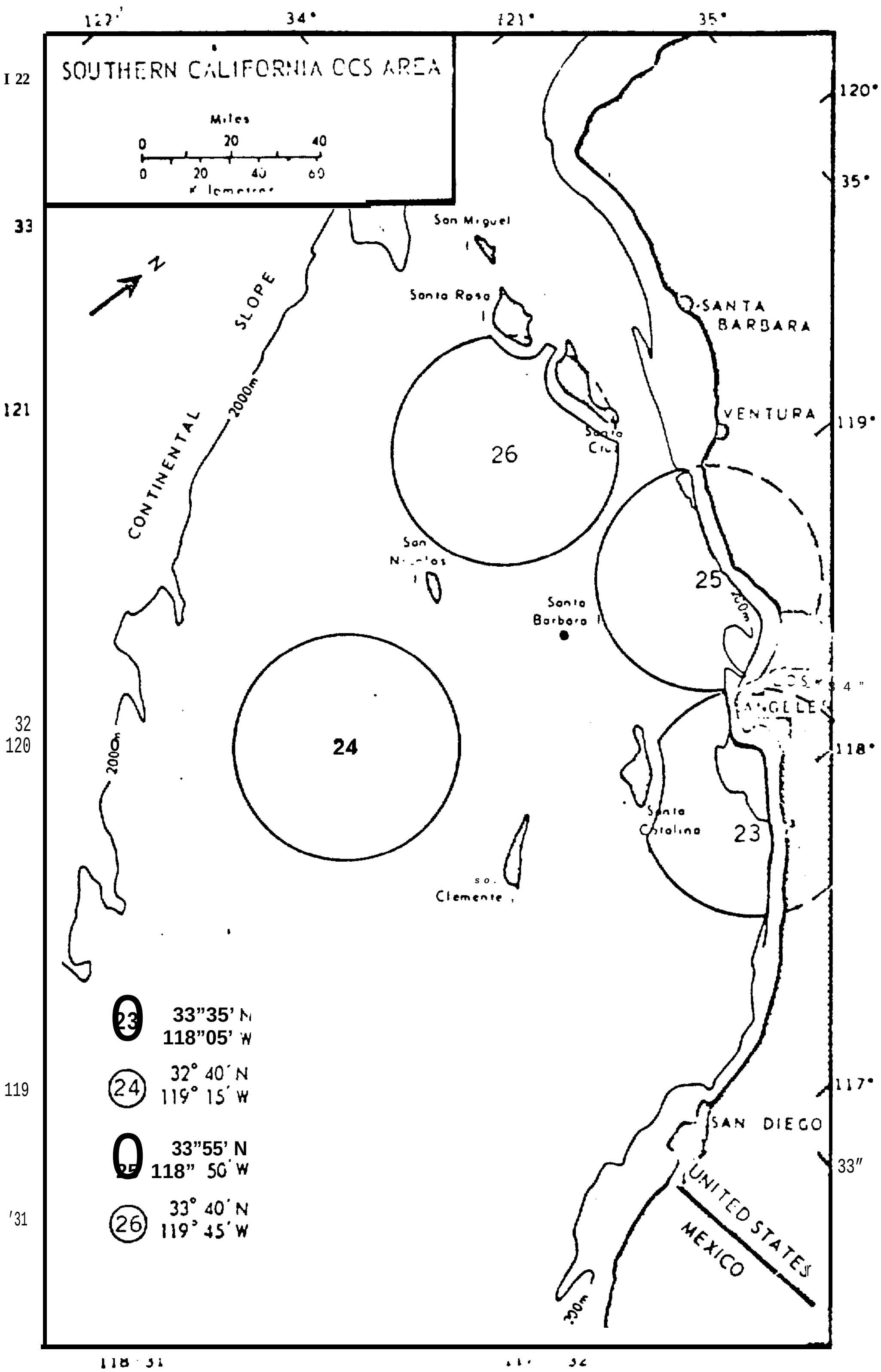
18 27°45′ N 93°00′ W



HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM

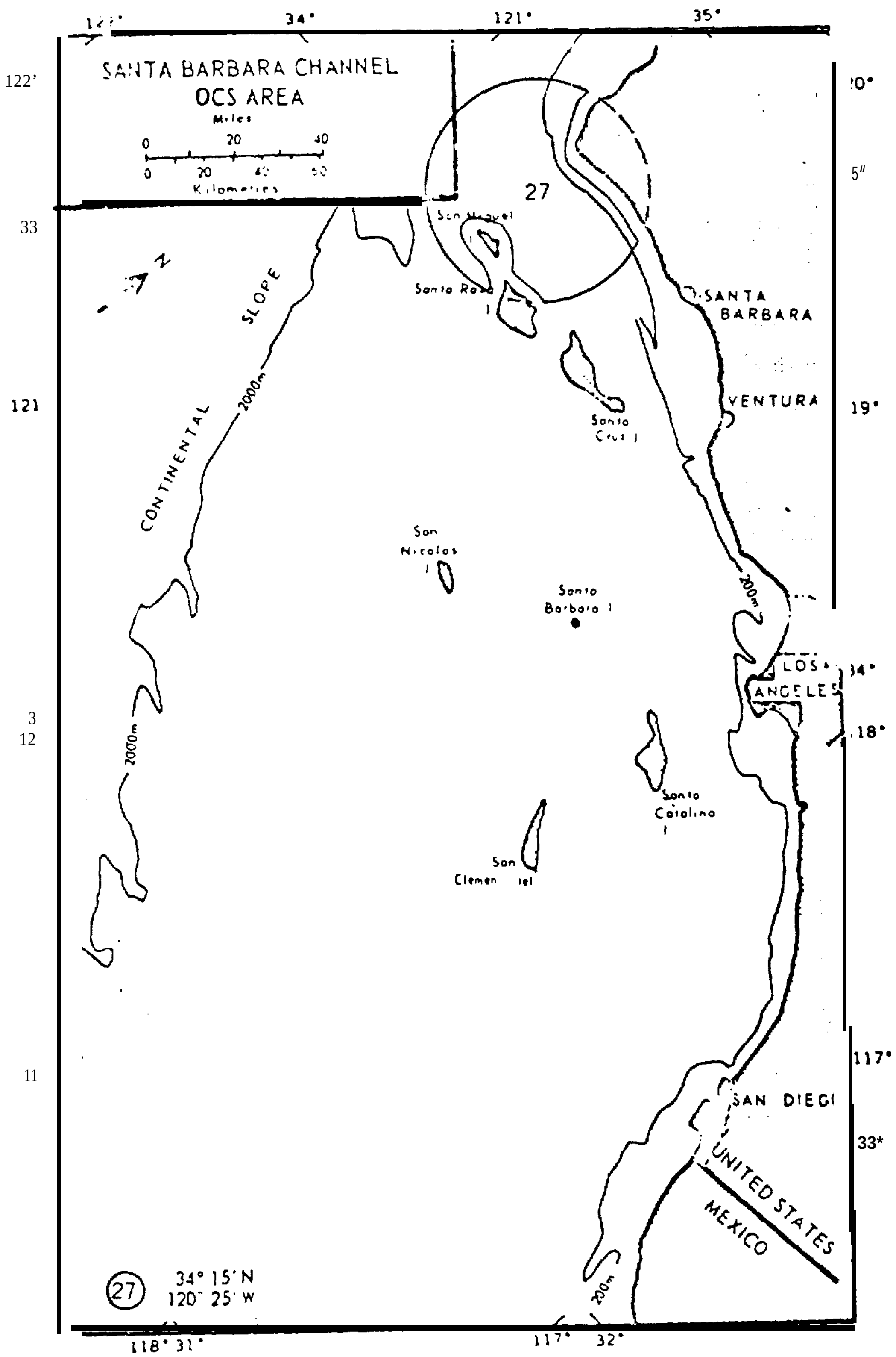
19 — 27° 45′ N 93°50′ W	20 — 27° 45′ N 94° 35′ W	21 — 27° 35′ N 96°25′ W	22 — 26° 20′ N 96° 40′ W

FIGURE 6



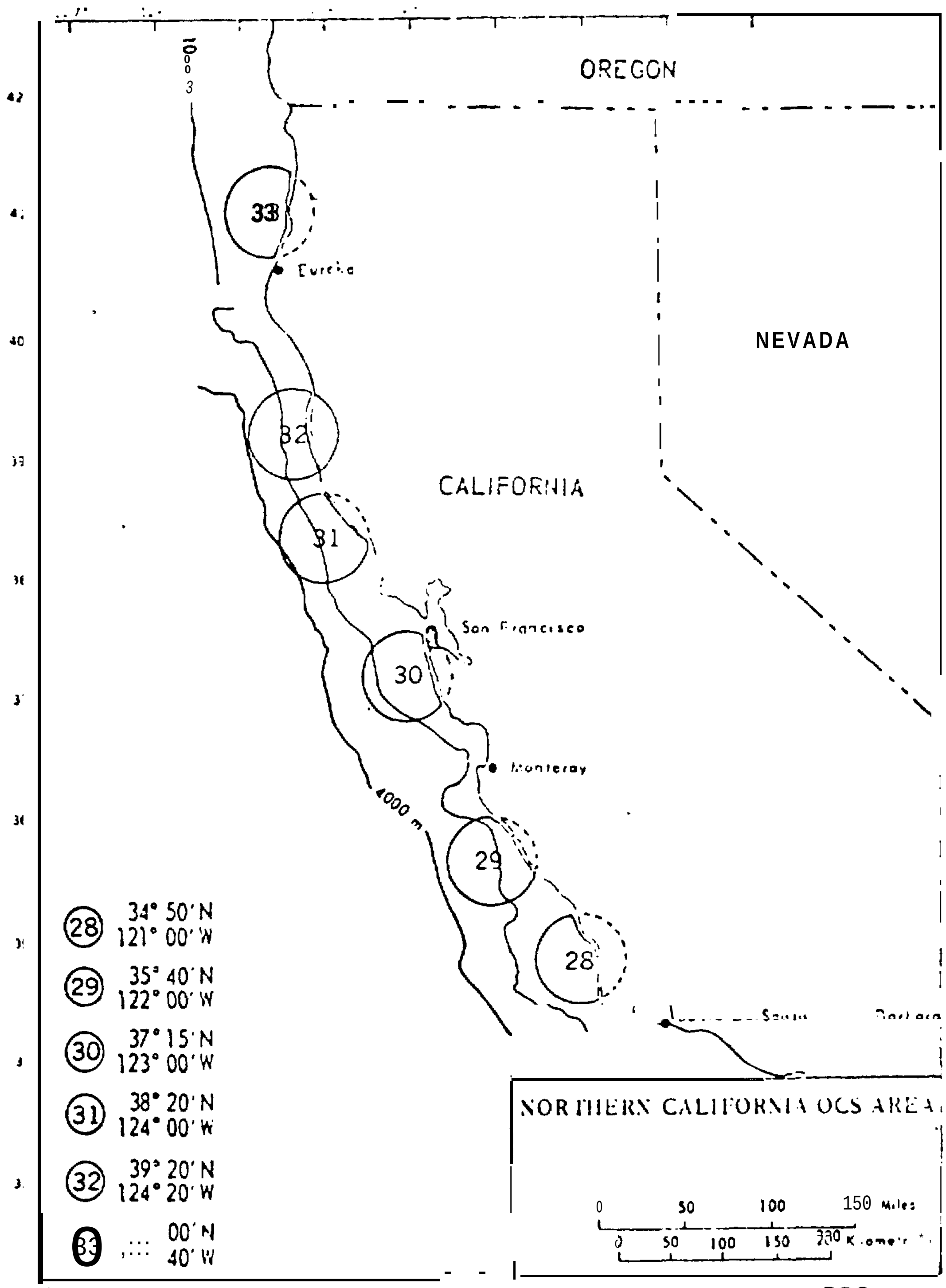
HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM

FIGURE 7



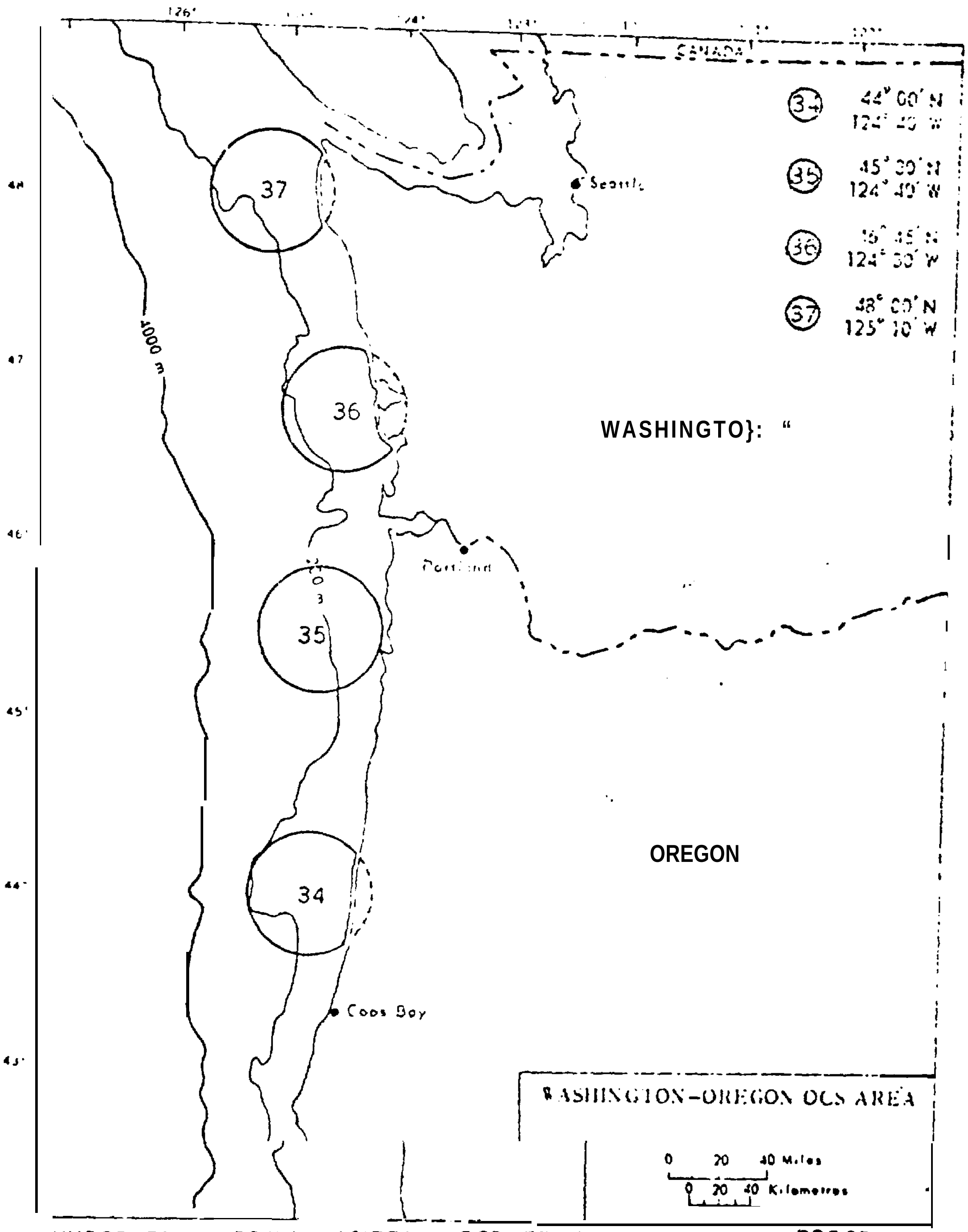
HYPOTHETICAL DRILLING SITE IN ACCELERATED OCS LEASING PROGRAM

FIGURE 8



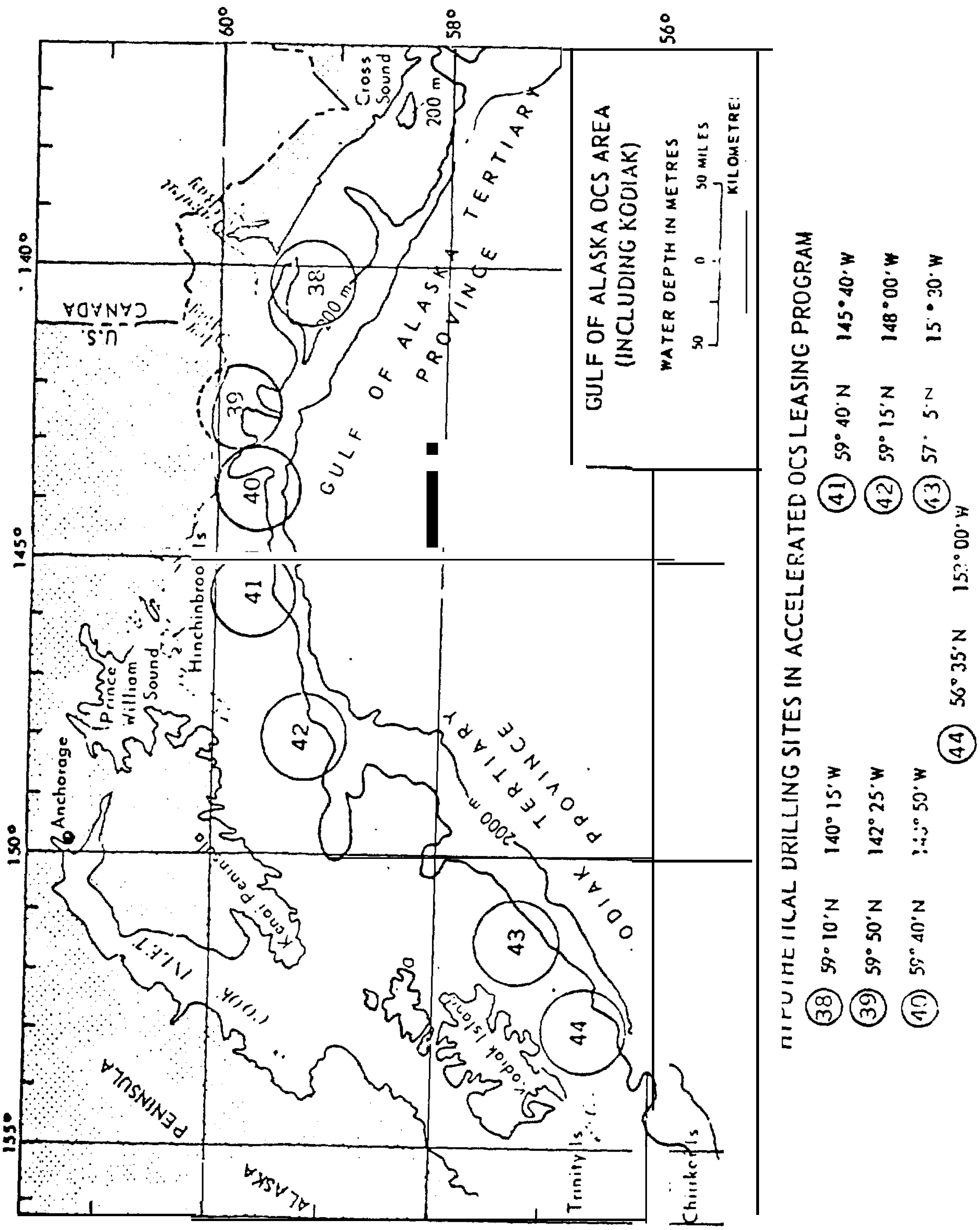
HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM

FIGURE 9



HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM

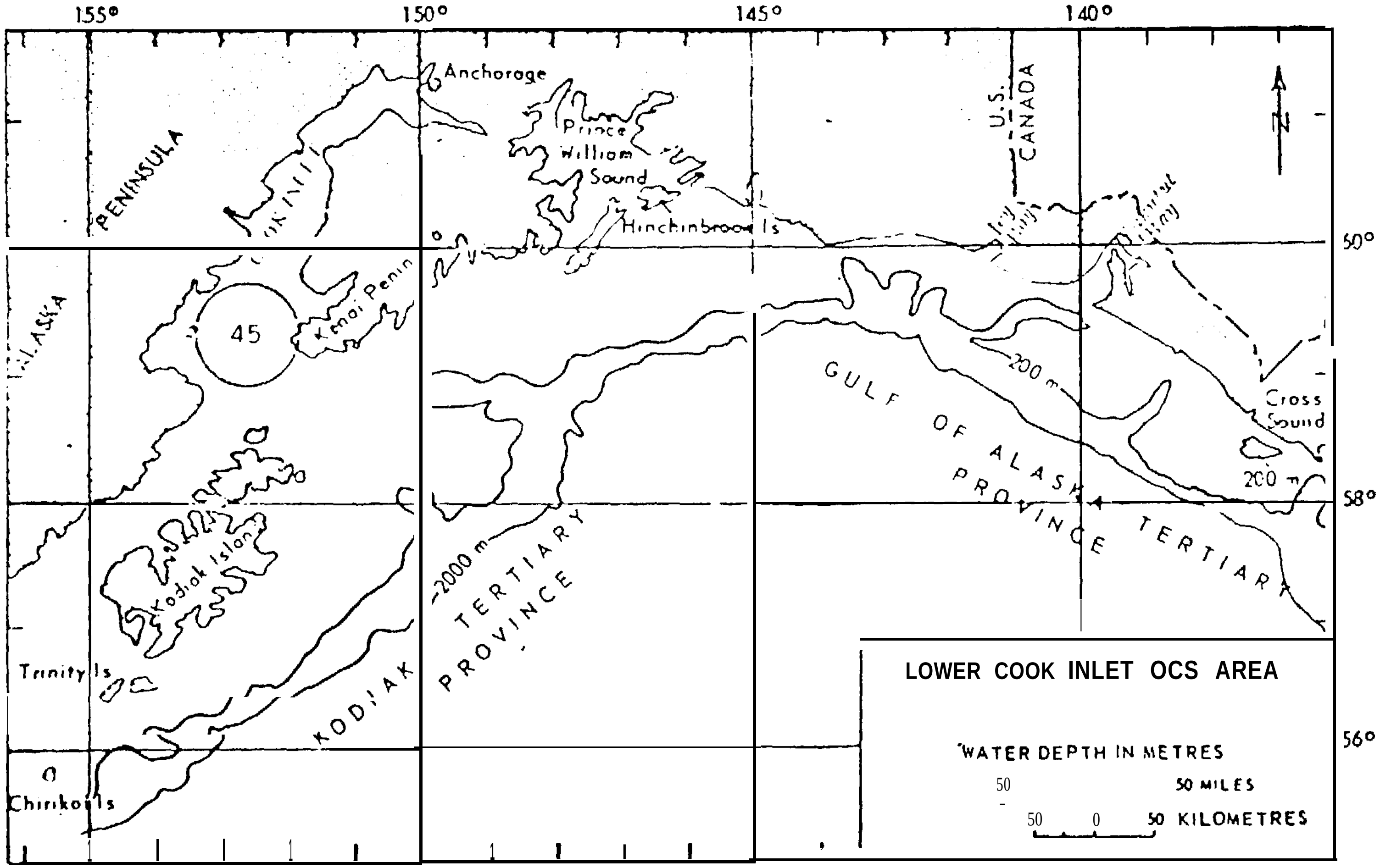
FIGURE 10



GULF OF ALASKA OCS AREA
(INCLUDING KODIAK)
WATER DEPTH IN METRES
50 0 50 MILES
KILOMETRES
DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM
38 59° 10'N 140° 15'W
39 59° 50'N 142° 25'W
40 59° 40'N
41 59° 40'N 145° 40'W
42 59° 15'N 148° 00'W
43 57° 5'N
44 56° 35'N
60°
58°
56°
140°
145°
150°
155°
U.S.
CANADA
Cross Sound
200 m
2000 m
GULF OF ALASKA
GULF OF ALASKA TERTIARY PROVINCE
KODIAK TERTIARY PROVINCE
Anchorage
Prince William Sound
Hinchinbrook Is
Kenai Penin.
COOK INLET
ALASKA PENINSULA
Kodiak Island
Trinity Is
Chirikof Is

FIGURE 11

FIGURE 12



HYPOTHETICAL DRILLING SITE IN ACCELERATED OCS LEASING PROGRAM

59° 20' N 152° 40' W

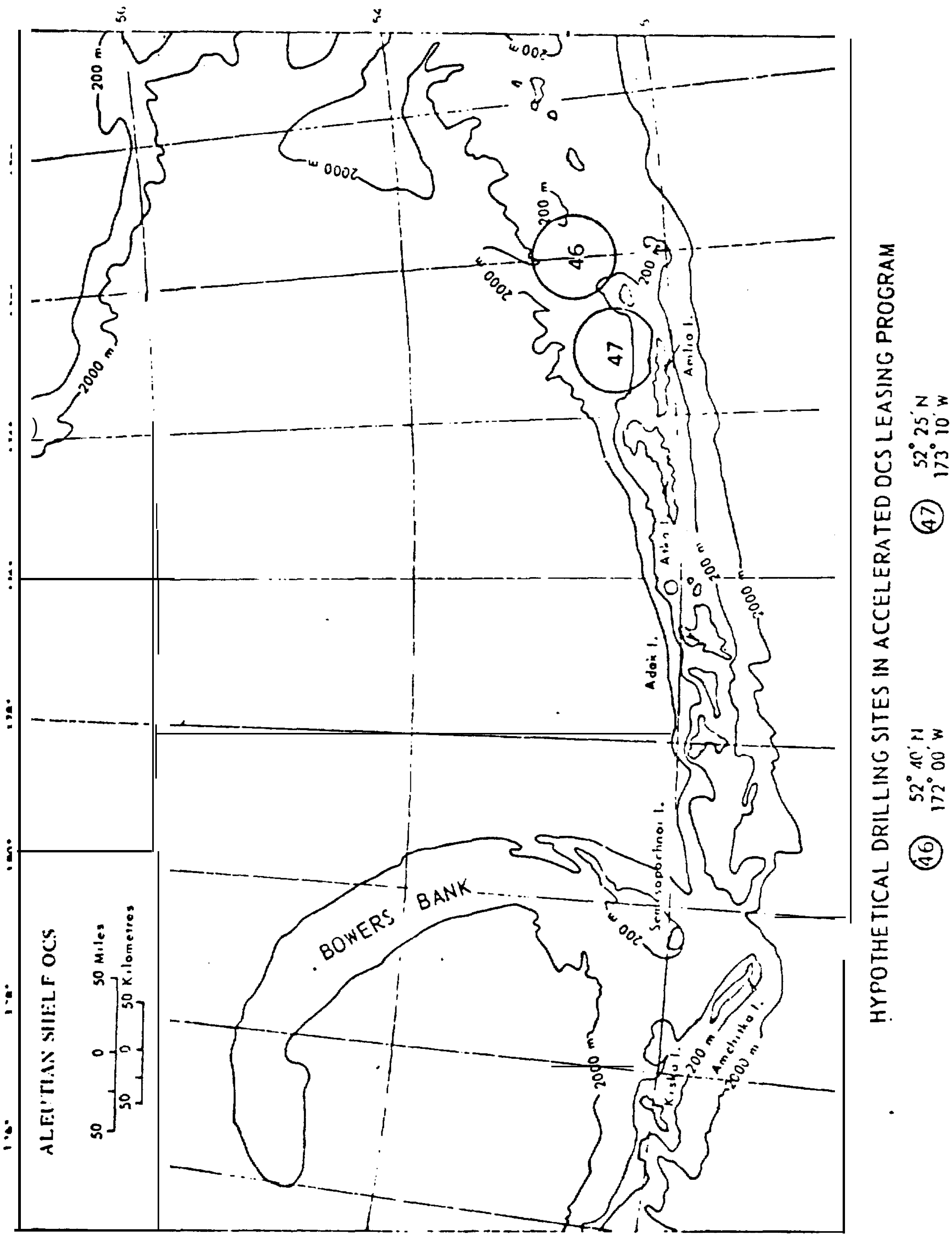

ALEUTIAN SHELF OCS
50 0 50 Miles
50 0 50 Kilometres
BOWERS BANK
Semisopochnoi I.
Kiska I.
Amchitka I.
Adak I.
Atka I.
Amlia I.
200 m
2000 m
46
47
HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM
46 52° 40' N 172° 00' W
47 52° 25' N 173° 10' W

FIGURE 13

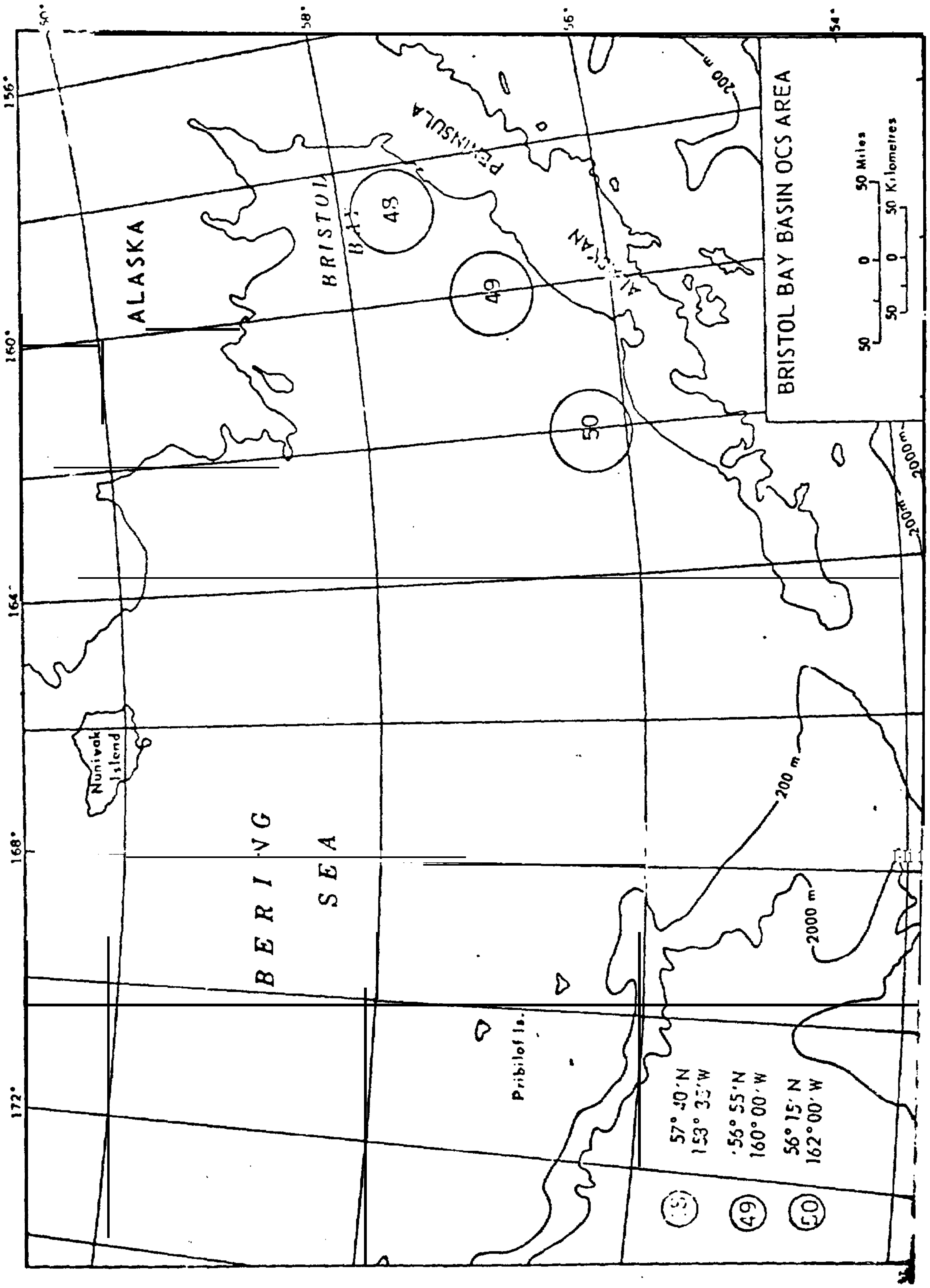

BRISTOL BAY BASIN OCS AREA
ALASKA
BERING SEA
BRISTOL
PENINSULA
Nunivak Island
Pribilof Is.
200 m
2000 m
50 Miles
50 Kilometres
57° 40' N 153° 33' W
56° 55' N 160° 00' W
56° 15' N 162° 00' W
48
49
50
156°
160°
164°
168°
172°
58°
56°
54°

FIGURE 14

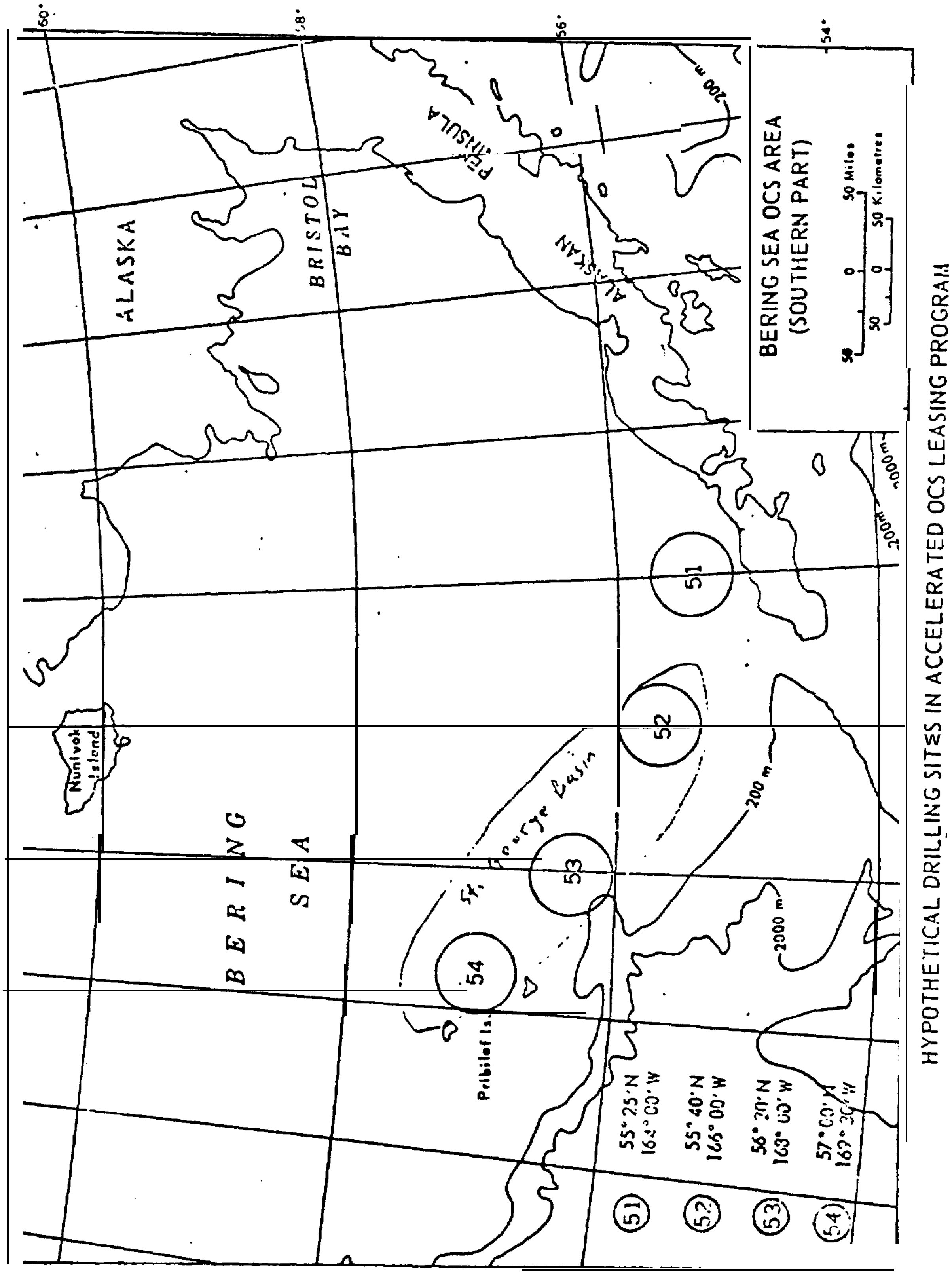

HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM
BERING SEA OCS AREA
(SOUTHERN PART)
50 Miles
50 Kilometres
ALASKA
BRISTOL BAY
BERING SEA
Nunivak Island
Pribilof Is.
200 m
2000 m
51
52
53
54
55° 25' N 164° 00' W
55° 40' N 165° 00' W
56° 20' N 163° 00' W

FIGURE 15

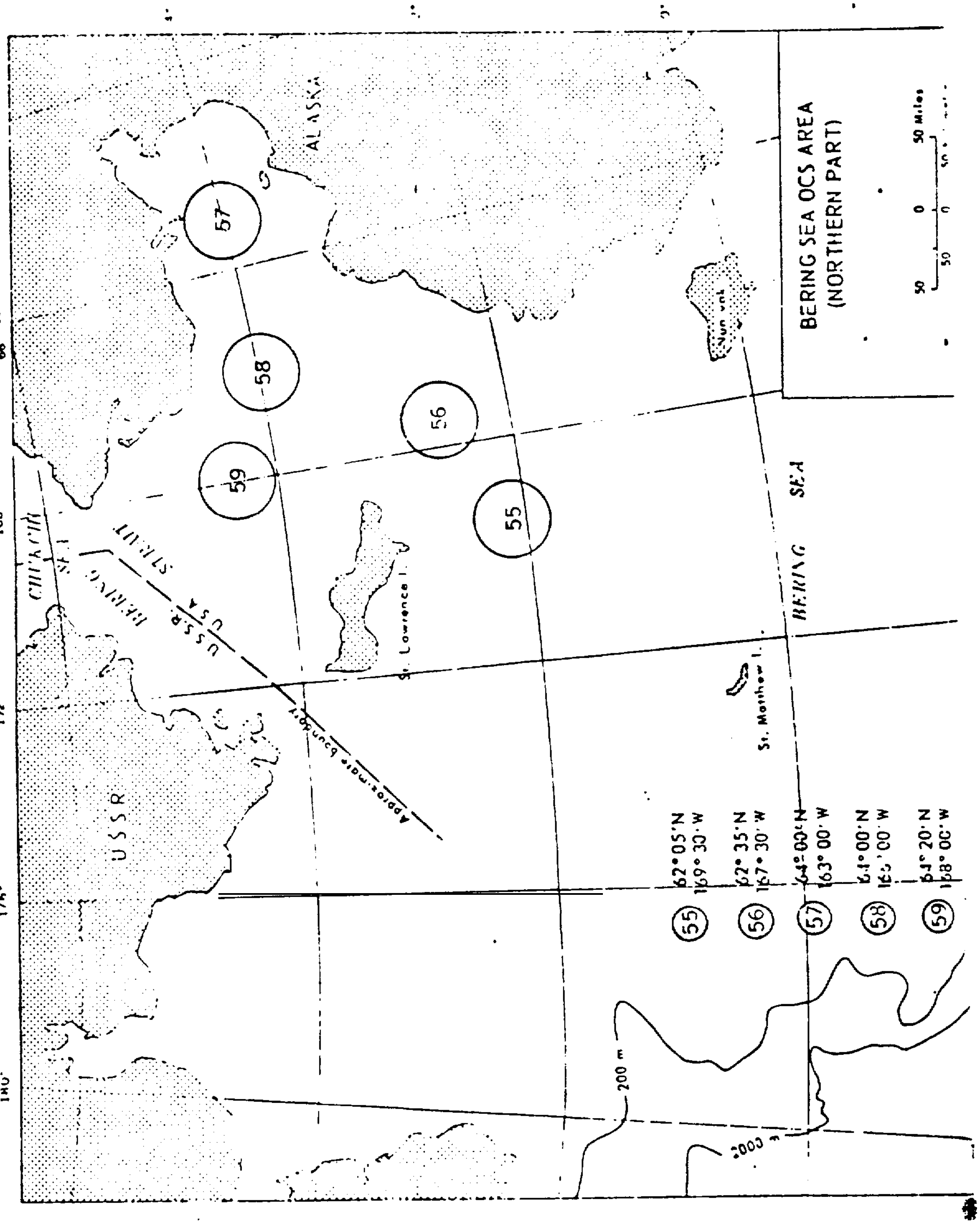
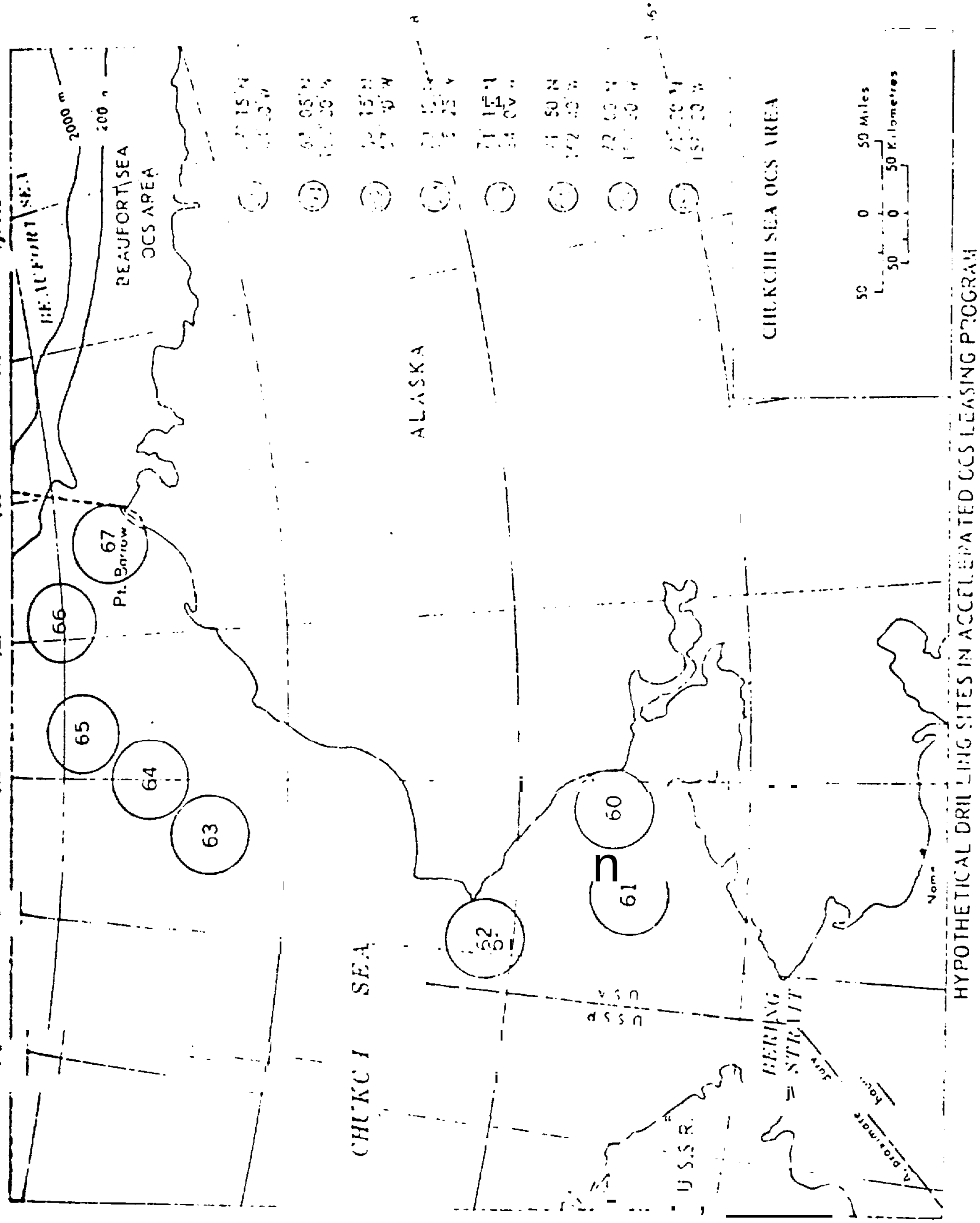

BERING SEA OCS AREA
(NORTHERN PART)
ALASKA
U S S R
St. Lawrence I.
St. Matthew I.
Approximate boundary
BERING SEA
USSR
USA
200 m
55
56
57
58
59
55 62° 05'N 169° 30'W
56 62° 35'N 167° 30'W
57 64° 00'N 163° 00'W
59 64° 20'N 168° 00'W

FIGURE 16


HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM
BEAUFORT SEA
BEAUFORT SEA OCS AREA
2000 m
200 m
CHUKCHI SEA OCS AREA
ALASKA
CHUKCHI SEA
BERING STRAIT
U.S.S.R.
Pt. Barrow
Nome
60
61
62
63
64
65
66
67
50 Miles
50 Kilometres

F IGURE 17

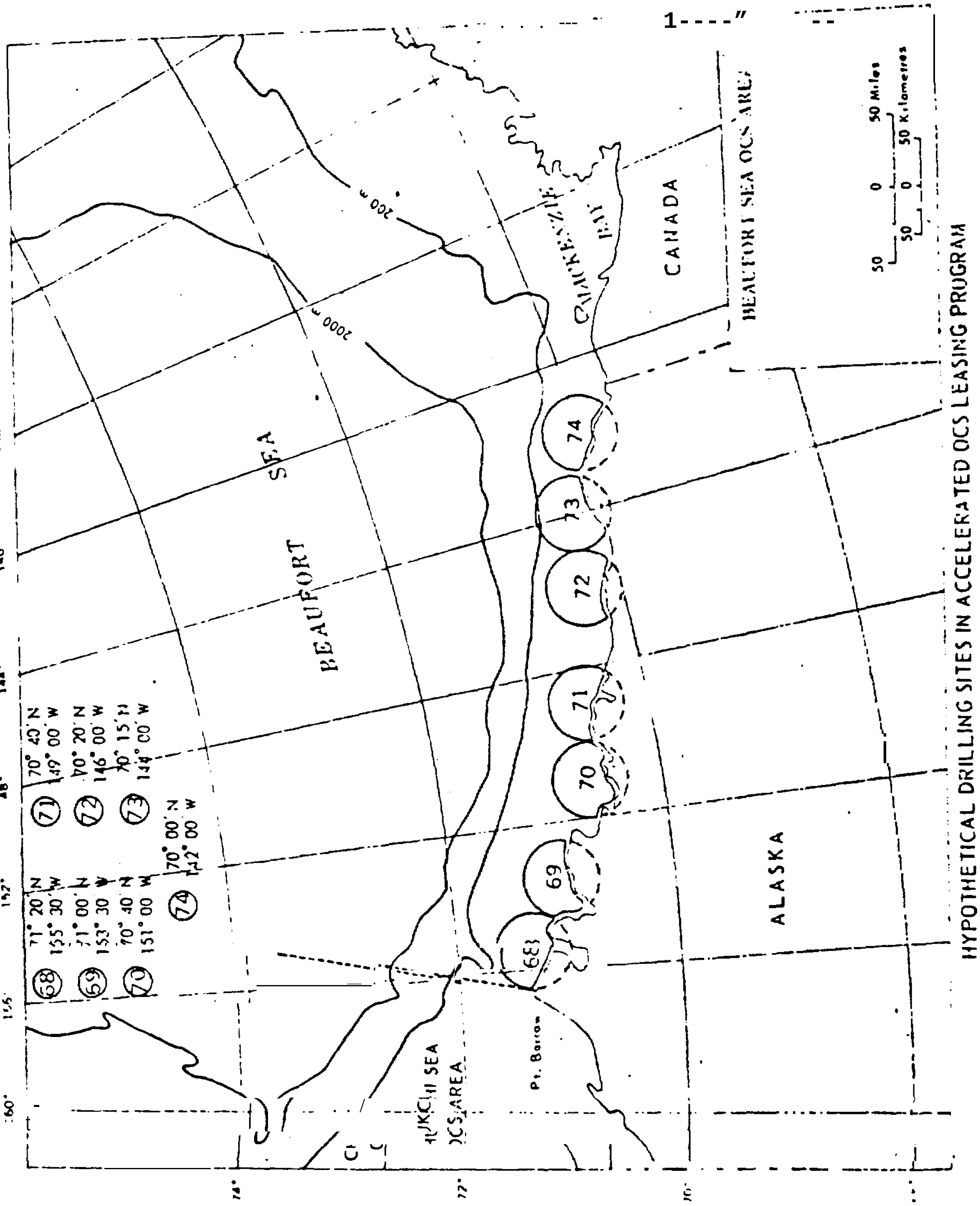

HYPOTHETICAL DRILLING SITES IN ACCELERATED OCS LEASING PROGRAM
BEAUFORT SEA
BEAUFORT SEA OCS AREA
MACKENZIE BAY
CANADA
ALASKA
Pt. Barrow
50 Miles
50 Kilometres
68 71° 20' N 155° 30' W
69 71° 00' N 153° 30' W
70 70° 40' N 151° 00' W
71 70° 40' N 149° 00' W
72 70° 20' N 146° 00' W
73 70° 15' N 144° 00' W
74 70° 00' N 142° 00' W

FIGURE 18

APPENDIX C

MINIMUM REQUIRED PRICES AND TOTAL INVESTMENT COSTS
BY FIELD SIZE FOR EACH OCS AREA

500/2,500/10,000 B/D WELL PRODUCTIVITY
MINIMUM REQUIRED PRICE AS A FUNCTION OF FIELD SIZE OIL
(Required Rate of Return - 15%)

($/B)[a]

Area/Case		Field Size in MMBS: 5	15	45	90	150	350	750	1400	2000	Case Assumptions: Water Depth (Feet)	Distance to Shore (Miles)	# Years Delay[b]
Atlantic -	500 B/D	43.34	18.34	10.08	7.81	7.50	6.59	5.71	5.65	5.78	400	75	4
	2,500 "	41.02	17.17	8.85	6.74	5.82	4.60	4.06	3.78	3.57	"	"	"
	10,000 "	40.63	16.94	8.70	6.49	5.54	4.34	3.56	3.15	3.10	"	"	"
Gulf of Mexico -	500 B/D	32.53	13.92	7.78	6.10	5.81	5.09	4.68	4.80	4.98	400	75	3
	2,500 "	30.76	13.02	6.87	5.31	4.63	3.71	3.26	3.02	2.90	"	"	"
	10,000 "	30.43	12.81	6.72	5.09	4.40	3.49	2.88	2.55	2.50	"	"	"
California -	500 B/D	45.77	19.44	10.50	7.47	6.91	5.91	5.26	5.21	5.32	600	15	4
	2,500 "	43.37	18.34	9.31	6.48	5.27	4.12	3.82	3.63	3.43	"	"	"
	10,000 "	43.02	18.12	9.16	6.24	5.01	3.89	3.35	3.02	3.01	"	"	"
Washington/Oregon -	500 B/D	46.09	19.59	10.58	7.51	6.94	5.93	5.27	5.22	5.33	600	15	4
	2,500 "	43.67	18.48	9.39	6.52	5.29	4.13	3.83	3.63	3.44	"	"	"
	10,000 "	43.32	18.26	9.24	6.28	5.04	3.90	3.36	3.03	3.02	"	"	"
Gulf of Alaska	500 B/D	114.96	45.86	22.99	15.59	14.03	11.61	10.10	9.77	9.90	400	25	5
	2,500 "	108.95	42.98	19.63	12.74	9.84	7.17	6.44	6.03	5.67	"	"	"
	10,000 "	108.36	42.68	19.44	12.25	9.26	6.61	5.44	4.80	4.79	"	"	"
Lower Cook Inlet -	500 B/D	78.14	32.43	17.41	12.05	10.51	8.70	7.58	7.44	7.57	200	15	5
	2,500 "	74.16	30.18	14.23	9.30	7.19	5.22	4.60	4.28	4.04	"	"	"
	10,000 "	73.66	29.91	14.06	8.81	6.61	4.66	3.77	3.33	3.29	"	"	"
Bering Sea -	500 B/D	109.88	42.19	20.27	14.32	12.67	10.56	9.05	8.88	9.04	200	75	5
	2,500 "	103.94	39.06	16.70	11.21	8.86	6.36	5.38	4.92	4.64	"	"	"
	10,000 "	103.26	38.71	16.51	10.66	8.20	5.73	4.42	3.82	3.75	"	"	"
Beaufort Sea -	500 B/D	156.55	60.04	28.71	19.32	16.66	13.49	11.63	11.33	11.50	300	15	5
	2,500 "	148.14	55.79	23.78	15.09	11.42	8.05	6.98	6.46	6.08	"	"	"
	10,000 "	147.24	55.30	23.47	14.31	10.51	7.17	5.70	4.98	4.92	"	"	"

[a] 1975$

[b] Number of years delay after date of Lease acquisition until first production is generated,

TABLE C2

20/50/100 MMCF/D WELL PRODUCTIVITY

MINIMUM REQUIRED RATE OF RETURN AS A FUNCTION OF GAS

(Required Rate of Return - 15%)
(S/MCF)[a]

Area/Case		Field Size in MMCF 50	100	250	500	1000	2500	5000	10000	20000	Case Assumptions: Water Depth (Feet)	Distance to Shore (Miles)	# Years Delay[b]
Atlantic -	20 MMCF/D	4.45	2.54	1.37	0.97	0.77	0.66	0.60	0.54	0.55	400	75	4
	50 "	4.43	2.53	1.36	0.96	0.75	0.61	0.51	0.48	0.45	"	"	"
	100 "	4.42	2.52	1.36	0.95	0.74	0.60	0.51	0.44	0.42	"	"	"
Gulf of Mexico -	20 MMCF/D	3.36	1.93	1.06	0.76	0.61	0.53	0.48	0.45	0.48	400	75	3
	50 "	3.35	1.92	1.05	0.75	0.59	0.49	0.42	0.39	0.38	"	"	"
	100 "	3.34	1.91	1.05	0.75	0.59	0.49	0.62	0.36	0.35	"	"	"
California -	20 MMCF/D	4.82	2.80	1.51	0.97	0.69	0.54	0.51	0.46	0.46	600	15	4
	50 "	4.80	2.79	1.50	0.96	0.67	0.50	0.42	0.40	0.39	"	"	"
	100 "	4.79	2.78	1.50	0.95	0.67	0.49	0.42	0.36	0.36	"	"	"
Washington /Oregon-	20 MMCF/D	4.88	2.85	1.55	0.99	0.70	0.55	0.51	0.46	0.46	600	15	4
	50 "	4.87	2.84	1.54	0.97	0.68	0.50	0.62	0.41	0.39	"	"	"
	100 "	6.86	2.83	1.53	0.97	0.68	0.49	0.42	0.36	0.36	"	"	"
Gulf of Alaska -	20 MMCF/D	12.16	6.83	3.46	2.06	1.35	0.97	0.88	0.78	0.76	400	25	5
	50 "	12.14	6.82	3.45	2.03	1.30	0.86	0.69	0.64	0.60	"	"	"
	100 "	12.13	6.81	3.45	2.03	1.30	0.84	0.67	0.56	0.54	"	"	"
Lower Cook Inlet -	20 MMCF/D	8.15	4.64	2.38	1.40	0.92	0.64	0.57	0.50	0.49	200	15	5
	50 "	8.14	4.62	2.37	1.38	0.87	0.56	0.44	0.41	0.38	"	"	"
	100 "	8.13	4.61	2.36	1.37	0.86	0.54	0.43	0.35	0.34	"	"	"
Bering Sea -	20 MMCF/D	11.14	5.98	2.84	1.77	1.24	0.94	0.81	0.71	0.71	200	75	5
	50 "	11.13	5.97	2.82	1.74	1.18	0.84	0.66	0.59	0.55	"	"	"
	100 "	11.11	5.96	2.82	1.74	1.18	0.82	0.64	0.52	0.49	"	"	"
Beaufort Sea -	20 MMCF/D	16.44	8.93	4.26	2.47	1.58	1.07	0.94	0.83	0.81	300	15	5
	50 "	16.60	8.90	4.23	2.43	1.50	0.93	0.72	0.65	0.60	"	"	"
	100 "	16.37	8.88	4.22	2,61	1.49	0.90	0.69	0.56	0.53	"	"	"

a 1975$.
b Number of years delay after date of discovery well until first production is generated.

TABLE C3

INVESTMENT AS A FUNCTION OF FIELD SIZE
(Required Rate of Return - 10%; Average Well Productivity OIL 2500 B/D)[a]
(MM 1975$)

a/Investment Type	Field Size (in MMB of Recoverable Reserves) 15	45	90	150	350	750	1400	2000-
antic								
ploration Wells (4)	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
latform Constr. and Installation	13.5	17.7	23.9	32.2	59.9	126.3	206.3	342.5
Development Wells	0.6	0.6	3.7	7.3	19.5	44.5	84.8	121.5
latform Equipment	3.2	9.6	16.1	25.7	55.7	118.3	195.3	323.9
ipeline to Shore	16.7	37.3	38.4	39.7	69.2	88.2	128.4	158.2
athering Lines	0.8	0.8	0.8	0.8	0,9	1.3	2.0	3.5
Inshore Terminal	2.1	6.3	12.9	21.3	49.2	103,8	188.4	262.8
Total Development	36.9	71.3	95.8	127.0	254.4	482.4	805.2	1212.4
nnual Production Cost	1.9	4.0	6.5	9.3	16,9	33.7	62.9	89.8
f of Mexico[b]								
xploration Wells (4)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
latform Constr. and Installation	9.3	12.6	16.S	30.5	66.5	147.2	268.8	365.6
evelopment Wells	1.6	8.6	19.1	32.4	78.4	169.9	318.4	456.0
latform Equipment	2.8	7.7	14.8	24.3	57.9	125.9	235.6	337.4
ipeline to Shore	14.0	31.1	32.4	33.8	61.2	74.8	94.8	108.0
athering Lines	0.5	0.5	0.5	0.9	1.6	4.1	6,4	9.4
nshore Terminal	2.2	6.6	13.4	22.2	51.6	108.6	188.4	239.6
Total Development	30.9	67.1	97.0	144.1	317.2	630.5	1112.4	1536.0
nnual Production Cost	1.4	3.2	5.4	9.1	21.9	46.4	82.2	106.0
lifornia								
Exploration Wells (4)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Platform Constr. and Installation	]6.5	21.6	29.3	39.4	73.2	154.7	252.7	419.5
Development Wells	0.6	0.6	3.0	6.0	16.1	36.5	69.4	99.4
Platform Equipment	3.1	8.4	15.9	25.4	55.1	117.0	193.1	320.3
Pipeline to Shore	7.4	16.6	16.8	17.2	18.8	21.6	26.2	30.6
Gathering Lines	0.5	0.5	0.5	0.5	0.6	0.9	1.4	2.4
Onshore Terminal	2.1	6.3	12.9	21.3	49.2	103.8	188.4	262.8
Total Development	30.2	54.0	78.4	109.8	213.0	434.5	731.2	1135.0
Annual Production Cost	1.5	3.5	5.6	8.1	15.1	30.7	57.4	82.0

xcept Gulf of Mexico

verage Well Productivity 50 B/D

TABLE C3 (continued)

INVESTMENT AS A FUNCTION OF FIELD SIZE
(Required Rate of Return - 10%; Average Well Productivity OIL 2500 B/D)[a]
(MM 1975$)

(Continued)

Area/Investment Type	15	45	90	150	350	750	1400	2000
	Field Size (in MMB of Recoverable Reserves)							
Washington-Oregon								
Exploration Wells (4)	8.0	6.0	8.o	8.0	8.0	8.0	8.0	8.0
Platform Constr. and Installation	16.5	21.6	29.3	39.4	73.2	154.7	252.7	419.5
Development Wells	0.6	0.6	3.0	6.0	16.1	36.5	69.4	99.4
Platform Equipment	3.1	8.4	15.9	25.4	55.1	117.0	193.1	320.3
Pipeline to Shore	7,8	17.2	17.6	18.0	19.6	22.8	28.2	33.9
Gathering Lines	0.7	0.7	0.7	0.9	0.8	1.2	1.8	3.0
Onshore Terminal	2.1	6.3	12.9	21.3	49.2	103.8	188.4	262.8
Total Development	30.8	54.8	79.4	110.9	214.0	436.0	733,6	1135.0
Annual Production Cost	1.5	3.5	5.7	8.1	15.1	30.7	57.4	82.1
Gulf of Alaska								
Exploration Wells (4)	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2
Platform Constr. and Installation	32.8	42.7	57.7	77.7	144.5	305.1	498.6	827.6
Development Wells	1.6	1.6	9.6	19.2	51.2	116.8	222.4	294.4
Platform Equipment	3.2	6.7	16.2	25.9	56.3	119.7	197.4	327.5
Pipeline to Shore	13.8	31.2	32.1	33.3	37.2	45.3	58.5	70,8
Gathering Lines	3.4	3.4	3.4	3.5	3.5	4.4	6.7	11.8
Onshore Terminal	2.4	7.4	14.8	24.6	57.0	120.2	217.6	302.2
Total Development	57.2	95.0	133.8	184.2	349.7	711.5	1201.2	1834.3
Annual Production Cost	3.1	6.5	10.0	13.9	23.9	47.8	89.6	128.1
Lower Cook Inlet								
Exploration Wells (4)	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6
Platform Constr. and Installation	il.-l	14.8	19.8	26.7	49.6	104,7	171.3	284,2
Development Wells	1.6	1.6	9.6	19.2	51.2	116,8	222.4	318.4
Platform Equipment	3.2	8.7	16.2	25.9	56.3	119.7	197.4	327.5
Pipeline to Shore	11.1	24.6	25.2	25.8	28.2	33.0	41.1	48.3
Gathering Lines	3.4	3.4	3.4	3.4	3.5	4.3	6.6	11.6
Onshore Terminal	2.4	7.2	14.1	23.4	54.6	115.5	210.6	294.3
Total Development	33.0	60.3	88.3	124.4	243.4	494.0	849.4	1284.3
Annual Production Cost	2.7	5.7	8.7	12.0	20.8	41.7	78.1	111.7

TABLE C3 (continued)

INVESTMENT AS A FUNCTION OF FIELD SIZE
(Required Rate of Return - 10%; Average Well Productivity OIL 2500 B/D)[a]
(MM 1975$)

(Continued)

Area/Investment Type	15	45	90	150	350	750	1400	2000
	Field Size (in MMB of Recoverable Reserves)							
Bering Strait								
Exploration Wells (4)	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8
Platform Constr. and Installation	11.3	14.8	19.8	26.7	49.6	104.7	171.3	284.2
Development Wells	1.9	1.9	11.1	22.2	59.3	135.1	257.3	368.3
Platform Equipment	3.2	9.0	16.8	26.9	58.6	124.4	205.3	340.5
Pipeline to Shore	L7.9	39.8	41.0	42.3	73.8	102.3	148.5	191.4
Gathering Lines	3.8	3.8	3.8	3.8	3.9	4.8	7.3	12.8
Onshore Terminal	2.7	8.4	16.8	27.9	64.8	137.4	251.4	350.4
Total Development	40.8	77.7	109.3	149.8	310.0	608.7	1041.1	1547.6
Annual Production cost	4.0	"7.4	11.0	15.0	25.0	49.2	92.2	131.9
Beaufort Sea								
Exploration Wells (4)	40.0	40,0	40.0	40.0 .	40.0	40.0	40.0	40.0
Platform Constr. and Installation	23.2	30.2	40.9	54.9	102.1	215.5	352.1	584.6
Development Wells	2.4	2.4	14.4	28.8	76.8	152.7	333.6	477.6
Platform Equipment	3.5	9.3	17.7	28.2	61.8	131.1	216.6	359.3
Pipeline to Shore	14.4	32.2	32.6	33.2	35.4	39.8	46.8	53.4
Gathering Lines	4.4	4.4	4.4	4.5	4.5	5.5	8.4	14.9
Onshore Terminal	2.8	8.6	17.0	28,2	65.6	138.2	252.7	353.1
Total Development	50.7	87.1	127.0	177.8	346.2	682.8	1210.2	1842.9
Annual Production Cost	3.9	8.5	13.5	19.1	34.0	68.9	129.2	18.4.8

TABLE C4

INVESTMENT AS A FUNCTION OF FIELD SIZE
(Required Rate of Return - 10%; Average Well Productivity Gas 50 MMMCF/D)[a]
(MM 1975$)

Area/Investment Type	Field Size (in MMMCF of Rec Res) 100	250	500	1000	2,500	5,000	10,000	20,000
Atlantic								
Exploration Wells (4)	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Platform Constr. and Installation	12.6	14.3	17.1	22.9	39.9	68.9	137.3	285.6
Development Wells	0.6	13.6	0.6	0.6	4.3	10.4	23.1	48.8
Platform Equipment	1.6	4.2	7.8	14.8	34.3	55.7	122.0	256.1
Pipeline to Shore	20.7	34.5	42.0	54.6	86.7	138.3	228.0	387.0
Gathering Lines	0.6	0.6	0.9	0.9	1.1	1.8	3.0	5.3
Onshore Terminal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Development	36.5	54.4	68.4	93.8	166.3	275.1	513.4	982.8
Annual Production Cost	1.8	3.9	7.1	13.1	29.9	56.3	113.5	227.8
Gulf of Mexico[b]								
Exploration Wells (4)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Platform Constr. and Installation	9.3	10.6	12.6	16.8	34.5	72.3	147.7	298.8
Development Wells	0.6	0.6	1.0	3.6	11.6	24.6	50.5	102.5
Platform Equipment	1.8	4.2	7.8	14.7	30.9	66.9	138.9	282.5
Pipeline to Shore	19.2	31.2	38.3	49.8	79.0	123.2	201.4	357.6
Gathering Lines	0.5	0.5	0.6	0.6	1.0	1.9	3.7	7.4
Onshore Terminal	0.0	0.0	0.0	0,0	0.0	0.0	0.0	0.0
Total Development	31.4	47.1	60.3	85.5	157.0	288.9	542.2	1048.8
Annual Production cost	1.5	3.4	6.3	11.9	29.0	58.3	116.6	233.1
California								
Exploration Wells (4)	8.0	8.0	8.0	8.0	8.0	8.0	8.0'	8.0
Platform Constr. and Installation	15.4	17.5	21.0	28.0	48.9	8.4.4	168.2	349.7
Development Wells	0.6	0.6	0.6	0.6	3.6	8.6	19.1	40.1
Platform Equipment	2.8	4.2	7.8	14.7	33.9	55.1	120.8	253.3
Pipeline to Shore	8.0	16.2	17.0	18.6	23.2	31.0	46.8	78.0
Gathering Lines	0.5	0.5	0.5	0,6	0.7	1.2	2.0	3.6
Onshore Terminal	0.0	0.0	0.0	0,0	0.0	0.0	0.0	0.0
Total Development	27.3	39.0	46.9	62.5	110.3	180.3	356.9	724.7
Annual Production Cost	1.6	3.6	6.5	12.0	27.2	51.9	104.7	210.2

[a] Except Gulf of Mexico

[b] Average Well Productivity 20 MMCF/D

TABLE C4 (continued)

INVESTMENT AS A FUNCTION OF FIELD SIZE
(Required Rate of Return - 10%; **Average Well Productivity** Gas 50 MMMCF/D)
(MM 1975$)
(Continued)

Area/Investment Type	Field Size (in MMMCF of Rec Res) 100	250	500	1000	2,500	5,000	10,000	20,000
Washington/Oregon								
Exploration Wells (4)	8.0	8.0	8.0	8.0	8.0	8.o	8.0	8.0
Platform Constr. and Installation	15.4	17.5	21.0	28.0	48.9	84.4	168.2	349.7
Development Wells	0.6	0.6	0.6	0.6	3.6	8.6	19.1	40.1
Platform Equipment	3.8	4.2	7.8	14.7	33.9	55.1	120.8	253.3
Pipeline to Shore	8.8	18.0	18.8	20.4	25.0	32.8	48.6	79.8
Gathering Lines	0.7	0.8	0.8	0.8	0.9	1.6	2.6	4.5
Onshore Terminal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Development	29.3	41.1	‘49.0	64.5	112.3	182.5	359.3	727.4
Annual Production Cost	1.6	3.6	6.5	12.0	27.2	51.9	104.7	210.2
Gulf of Alaska								
Exploration Wells (4)	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2
Platform Constr. and Installation	30.5	34.5	41.5	55.1	96.5	116.6	331.9	689.9
Development Wells	1.6	1.6	1.6	1.6	11.2	27.2	60.8	126.4
Platform Equipment	3.6	4.3	7.9	15.1	34.8	43.8	123.3	258.7
Pipeline to Shore	18.3	36.9	38.4	41.1	49.8	64.2	93.3	150.9
Gathering Lines	3.5	3.6	3.6	3.7	3.8	3.3	9.5	14.8
Onshore Terminal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Development	57.5	80.9	93.0	116.6	196.1	255.1	618.8	1240.7
Annual Production Cost	2.7	5.8	9.9	17.0	35.8	65.8	133.,5	268.7
Lover Cook Inlet								
Exploration Wells (4)	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6
Platform Constr. and Installation	10.4	11.9	14.2	18.9	33.1	40.0	113.9	236.9
Development Wells	1.6	1.6	1.6	1.6	11.2	27.2	60.8	128.0
Platform Equipment	3.6	4.3	7.9	15.1	34.8	43.8	123.3	258.7
Pipeline to Shore	13.8	27.9	28.8	30.6	35.7	44.4	61.8	96.3
Gathering Lines	3.4	3.4	3,4	3.5	3.6	3.1	8.9	13.6
Onshore Terminal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Development	32.8	49.1	55.9	69.7	118.4	158.5	368.7	733.5
Annual Production Cost	2,4	5.2	8.9	15.3	32.2	59.2	120.2	241.8

TABLE C4 (continued)

INVESTMENT AS A FUNCTION OF FIELD SIZE
(Required Rate of Return - 10%; Average Well Productivity Gas 50 MMMCF/D)
(MM 1975$)

(Continued)

Area/Investment Type	100	250	500	1000	2,500	5,000	10,000	20,000
	Field Size (in MMMCF of Rec Res)							
Bering Strait								
Exploration Wells (4)	28.8	28.8	28.8	28.8	28.8	28.8	28.8	48.8
Platform Constr. and Installation	10.4	11.9	14.2	18.9	33.1	40.0	113.9	236.9
Development Wells	1.9	1.9	1.9	1.9	13.0	31.5	70.4	148.1
Platform Equipment	3.6	4..4	8.1	15.4	36.0	45.5	128.1	268.7
Pipeline to Shore	25.5	42.4	49.4	64.1	100.8	153.8	246.8	432.6
Gathering Lines	3.9	4.0	4.0	4.0	4.2	3.6	10.2	.5 .5
onshore Terminal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Development	45.3	64.6	77.6	104.3	187.1	274.4	569.4	1102.0
Annual Production Cost	3.0	6.2	10.6	18.4	39.0	70.9	143.9	289.8
Beaufort Sea								
Exploration Wells(4)	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Platform Constr. and Installation	21.5	24.4	29.3	38.9	68.1	82.4	234.3	487.2
Development Wells	2.4	2.4	2.4	2.4	16.8	40.8	91.2	192.0
Platform Equipment	3.8	4.6	8.7	16.2	37.7	47.9	134.9	282.8
Pipeline to Shore	16.0	32.4	33.6	35.6	44.4	52.0	72.4	113.4
Gathering Lines	4.5	4.6	4.6	4.7	4.8	4.1	11.8	17.9
Onshore Terminal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Development	48.2	68.4	78.6	97.8	171.8	227.2	544.6	1093.3
Annual Production Cost	3.7	7.6	12.6	21.2	42.5	76.4	156.2	315.7