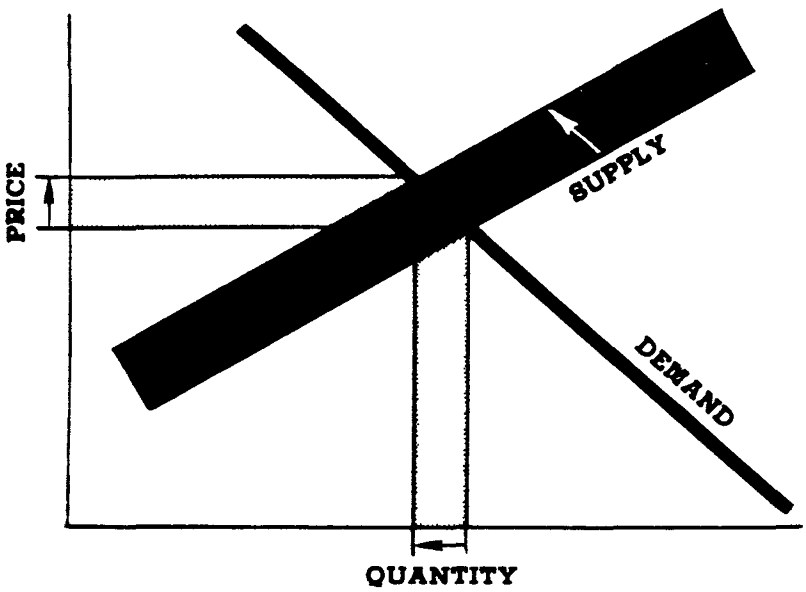
EPA-230/1-75-063 (A)
JULY 1975

ECONOMIC ANALYSIS
OF
PROPOSED AND INTERIM FINAL EFFLUENT GUIDELINES
OF
THE OFFSHORE OIL AND GAS PRODUCING INDUSTRY



U.S. ENVIRONMENTAL PROTECTION AGENCY
Economic Analysis Section
Office of Water and Hazardous Materials
Washington, D.C. 20460

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ECONOMIC ANALYSIS

OF

PROPOSED AND INTERIM FINAL EFFLUENT GUIDELINES

OF

THE OFFSHORE OIL AND GAS PRODUCING INDUSTRY

report to

U.S. Environmental Protection Agency

Economic Analysis Section

Office of Water and Hazardous Materials

Washington, D.C. 20460

Partial Fulfillment of

Contract No. 68-01-1541

Task 20

July 31, 1975

PREFACE

The attached document is a contractor's study prepared for the Office of Water and Hazardous Materials, Economic Analysis Section, of the Environmental Protection Agency ("EPA"). The purpose of the study is to analyze the economic impact which could result from the application of alternative effluent limitation guidelines and standards of performance to be established under sections 304(b) and 306 of the Federal Water Pollution Control Act, as amended.

The study supplements the technical study ("EPA Development Document") supporting the issuance of international regulations under sections 304(b) and 306. The Development Document surveys existing and potential waste treatment control methods and technology within particular industrial source categories and supports the proposal based upon an analysis of the feasibility of these guidelines and standards in accordance with the requirements of sections 304(b) and 306 of the Act. Presented in the Development Document are the investment and operating costs associated with various alternative control and treatment technologies. The attached document supplements this analysis by estimating the broader economic effects which might result from the required applications of various control methods and technologies. This study investigates the effect of alternative approaches in terms of product price increases, effects upon employment and the continued viability of affected plants, effects upon foreign trade and other competitive effects.

The study has been prepared with the supervision and review of the Office of Water and Hazardous Materials, Economic Analysis Section of EPA.

This report was submitted in partial fulfillment of Contract No. BOA 68-01-1541, Task Order No. 20, by Arthur D. Little, Inc., Cambridge, Massachusetts. Work was completed as of July, 1975.

This report is being released and circulated at approximately the same time as publication in the Federal Register of a notice of interim final and proposed rule making under sections 304(b) and 306 of the Act for the subject point source category. The study is not an official EPA publication. It will be considered along with the information contained in the Development Document and any comments received by EPA on either document before or during proposed rule making proceedings necessary to establish final regulations. Prior to final promulgation of regulations, the accompanying study shall have standing in any EPA proceeding or court proceeding only to the extent that it represents the views of the contractor who studied the subject industry. It cannot be cited, referenced, or represented in any respect in any such proceeding as a statement of EPA's views regarding the subject industry.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. EXECUTIVE SUMMARY

I.1. SCOPE OF WORK

The U. S. Environmental Protection Agency (EPA) is issuing interim final effluent guidelines for the 1977 Best Practicable Technology Currently Available and proposed effluent guidelines for the 1983 Best Available Technology and the New Source Performance Standards for offshore oil and gas production. An economic impact analysis of the guidelines was performed by Arthur D. Little, Inc. (ADL), under contract with the EPA and is reported here.

The economic impact analysis evaluated how many well completions would be shut in rather than brought into compliance, the investment required by the operators to come into compliance, and how much oil and gas production would be foregone as a result of the guidelines.

The impact analysis used costs of compliance developed by EPA and given a general review by ADL. The capability of the assumed treatment technologies to meet the effluent standard and the availability of platform space for installing the equipment has not been evaluated by ADL.

Oil and gas is currently produced from three offshore U.S. areas: the Gulf of Mexico, California, and Alaska's Cook Inlet. In 1973 the Gulf of Mexico produced 74% of U.S. offshore oil and 97% of offshore gas. California produced 15% and 1%, respectively, and Alaska produced 11% and 2% of offshore oil and gas.

The economic impact analysis deals principally with the regulation's effects in the Gulf of Mexico. This is the area with the majority of production and the area to experience the major impact. Over 95% of the production from offshore California leases appears to be in compliance at this time with the 1983 treatment requirement. The potential impact of the guidelines on Cook Inlet production has not been possible to treat completely because of a lack of relevant data on the costs of production and the costs of treatment and reinjection. The potential impacts on Cook Inlet production have been discussed qualitatively.

I.2. INDUSTRY DESCRIPTION

Beginning in the late 1940's, oil and gas have been produced from fields off the U.S. coast. In 1973, 17% of total United States oil production and 17% of gas production was from offshore wells. While there was a small fall-off in offshore oil production in the early 1970's, the offshore areas are generally regarded as an increasingly important source of oil and gas production.

Historically, offshore operations have been dominated by the larger oil companies. In 1971, 63% of offshore oil production was from wells owned by individual majors and another 34% was from wells owned by groups of majors. The Department of the Interior has encouraged the participation by smaller firms in recent years and the predominance of the majors is declining.

Revenues from offshore oil production amounted to $1.64 billion as compared with total U.S. oil production revenues of $10.35 billion in 1973. Revenues from offshore natural gas production were about $740 million in 1973.

Prices of oil and gas are partially regulated. Oil sold without price regulations has a price approximately corresponding to the world market, while regulated oil is sold at \$5.25 per barrel. Natural gas sold in intrastate markets is selling at prices determined by supply and demand; however, natural gas sold in interstate markets (the majority of Gulf of Mexico production) is regulated to be \$0.51 per thousand cubic feet (MCF)).

The prices of both oil and natural gas are a subject of strong debate. Serious proposals exist to deregulate both old oil and natural gas in order to encourage more exploration and development of domestic supplies. On the other hand, major groups, such as segments of the Congress, believe oil prices in particular are too high and more controls should be imposed. The economic impact analysis has tested a range of potential prices since it is not possible to say with any certainty what future price levels will be.

The profitability of the oil industry has also been a subject of considerable debate. Historically, the industry has been about as profitable as the average U.S. manufacturing sector. However, a shadow of uncertainty exists because of pending decisions by Government agencies on a number of proposals which would vitally affect the industry. Tax policies have already been changed and may be changed again. Decisions on price controls and the excess profits taxes are not resolved. The resolution of these conflicting influences on the industry will be of far greater importance to its profitability and financial structure than the proposed pollution abatement regulations

I.3. SUMMARY OF CONCLUSIONS

Based upon the assumptions stated in the body of this report, the major conclusions of the economic impact analysis of the proposed effluent guidelines on offshore U.S. oil and gas production and the producing companies can be summarized as follows.

1. The capital investment required to bring wells producing in 1974 in the Gulf of Mexico into compliance will be approximately $64-145 million in 1977 and $50-56 million in 1983 in 1974 dollars. Additional investment will be required for wells drilled in the Gulf after 1974.

2. Since almost all production from leases off the California coast is now in compliance with the proposed regulations, additional required investments will likely be very small, if any.

3. The required investment for bringing offshore Alaska production into compliance has not been determined. The costs will be higher than in the Gulf of Mexico on a per barrel of water treated basis.

4. The average costs including capital recovery of producing oil from wells completed in or prior to 1974 in the Gulf of Mexico will be increased by about 9-31 cents per barrel in federal waters and about 12-16 cents per barrel in state waters in 1977. The production cost increase in state waters in 1983 will

be about \$.77-\$1.08 per barrel. The costs of producing natural gas from gas wells in the Gulf will be increased by less than one-half cent per MCF in federal waters and state waters in 1977. The estimated increase in production costs in 1983 will be about one cent per MCF in state waters. Production cost increases associated with California wells are expected to be negligible.

5. For oil wells producing in 1974 in the Gulf of Mexico, and for which no price increases are possible, the effluent guidelines will result in 14-28 million barrels of oil and lease condensate not being ultimately produced, due primarily to shortened well life after 1983 rather than well closures in 1977 or 1983. The foregone production represents 0.6% to 1.2% of the total remaining potential production from the wells from 1977 to the end of their economic life, which may be beyond the year 2000, in the absence of the guidelines. Similarly, the foregone production of non-associated and associated natural gas will be 81 to 249 million MCF in the absence of price increases to recover the costs which represent 0.3% to 1.0% of the total potential production from 1977 on.

6. There will be no closures of companies as a direct result of application of the guidelines.

7. There will be no significant effects on the profitability of the industry as a whole. The profitability of firms operating primarily in state waters might be affected.

8. The added estimated investment in offshore treatment and reinjection equipment for the Gulf of Mexico represents approximately 0.2-0.4% of expected total industry capital investment in offshore production ($48 billion) during the 1976-1983 period. As such, the pollution abatement-related investment should not materially alter investment plans of the industry.

9. The guidelines are not expected to discourage the exploration for or development of new oil or gas wells. However, the total lifetime production of the new wells will be reduced. The 0.6% to 1.2% reduction in volume produced over the remaining lifetime in the absence of price increases of existing oil wells in the Gulf of Mexico can be regarded as an upper limit to the percentage reduction in total lifetime production of oil from new wells. It's an upper limit because the value of total lifetime production of the wells producing in 1977 is significantly larger than their remaining lifetime production value as of 1977. The 0.3% to 1.0% loss of remaining gas production can also be regarded as an upper limit for the foregone gas production from new wells if price increases are not possible to recover the pollution abatement costs for the same reason.

10. U.S. crude oil prices are now controlled (old oil) or move with the world oil price (new or released oil). The higher production costs resulting from compliance with the proposed regulations may be recoverable through allowed increases in old oil prices, though such an allowance is not assured, nor are the procedures for allowing such an increase well established. The higher production costs associated

with uncontrolled oil already priced competitively with imported oil will likely not be recovered through price increases directly resulting from the added pollution control cost. The added operating costs of pollution control would result primarily in reduced revenues for the producer.

11. The increases in the costs of producing interstate natural gas (the majority of Gulf of Mexico production) will probably be substantially recovered by price increases approved by the FPC. The procedure for allowing such cost recoveries is well established, though cumbersome, and the pattern of recent FPC decisions indicates that the FPC would rule favorably on price increases to recover increased operating costs as a result of new government regulations.

12. The reduction in U.S. oil and gas production will be made up primarily by imports. At $11 per barrel, the foregone oil production from wells producing in 1974 represents $154 to $306 million in oil purchases abroad which would not otherwise have been made over about 25 years. The lost gas production from 1974 wells would require purchases of $162-498 million of foreign natural gas at $2.00 per MCF also over about 25 years. The required purchase of imported oil and gas assumes the foregone domestic production will not be replaced by coal, or nuclear power, and that U.S. domestic production will not equal U.S. demand over the 25 year period.

TABLE I-1

SUMMARY OF ECONOMIC IMPACTS

THE OFFSHORE OIL AND GAS EXTRACTION INDUSTRY

(Portion of SIC 1311)

Industry Description	Gulf of Mexico	California	Alaska
Number of Platforms	750	14	14
Number of Platforms Directly Discharging	510	0	14
Number of Platforms with BPCTCA in Place	180	14	NA

Costs (1974 Dollars) (Gulf of Mexico wells producing in 1974)	BPCTCA	BATEA
Total for Industry	$64-145 million	$50-56 million
Average per Platform	.11-.25 million	.09-.10 million
Percent of Average Annual Investment in Offshore Production	1-2%	0.7%
Annual		
Total for Industry	$36-78 million	$20 million
Average per Platform	$71-153 thousand	$40 thousand
Percent of Sales		
Oil (Federal waters)	1%-3%	none
Gas (Federal waters)	0.3%-1%	none
Expected Price Increases (due to added pollution control costs)		
Oil	none	none
Gas	$<$ 0.5%	2%
Platform Closures (rather than invest in abatement equipment)	4	27

TABLE I-1 (Con't)

	BPCTCA	BATEA
Foregone Production (between 1977 and 2000) (from wells producing in 1974)		
Oil	14-28 million bbl's (0.6%-1.2% of potential)	
Gas	80-250 million MCF (0.3%-1.0% of potential)	
Jobs Lost	none	none
Community Effects	none	none
Impact on Industry Growth	none	none
Balance of Payment Effects (Over 25 years)	$316 to $804 million	

SOURCE: Arthur D. Little, Inc., estimates

II. CHARACTERIZATION OF THE OFFSHORE OIL AND GAS EXTRACTION INDUSTRY

II.1. INDUSTRY STRUCTURE

1.1. Industry Definition

The activities of the oil and gas industry to be covered by the proposed and interim final effluent limitation guidelines and the New Source Performance Standards include production from offshore oil and gas wells.

This report applies only to those offshore production facilities physically attached to and an integral part of the production equipment. Firms which are primarily engaged in contract exploration activities or contract drilling of wells are not covered by the effluent guidelines. The drilling and exploration activities of firms operating offshore wells are also not covered by the regulations.

1.2. Offshore Oil and Gas Production

Following lease sales to interested parties, the first phase of offshore development begins with exploratory drilling from mobile drilling rigs which are positioned over suitable geological features located previously by geophysical techniques. The purposes of exploratory drilling are to define the existence of oil and/or gas fields. Results of exploratory drilling are used to establish a plan for the development of the newly discovered accumulations. Several or more wells may be drilled to confirm or deny the presence of hydrocarbons on any given oil and gas prospect.

The second phase of offshore development begins with the installation of fixed platforms from which a number of wells are directionally drilled to tap the hydrocarbon pools existing in the oil and gas field. Offshore drilling procedures are much the same as drilling on land, except that marine drilling requires special equipment and considerable logistical support with resulting higher costs/foot drilled than on onshore prospects.

The engineering, construction, and operation of fixed offshore platforms has evolved gradually since the first well was drilled out of sight of land off of the coast of Louisiana in 1947. As offshore development activity has moved into deeper waters and increasingly hostile environments, fixed platforms have become extremely large, self-contained facilities which can support as many as 30 or 40 development wells. As the majority or all of the development wells from a platform are completed, the platform begins production of one or a combination of crude oil, natural gas and gas condensate. Formation water -- typically a salt brine -- is usually produced in conjunction with oil.

Typically, several producing platforms are linked by a pipeline gathering system to a centrally located production processing platform. If oil and gas are produced in association with each other (a common case), the two are separated at the processing platform. When only gas is produced, it may require removal of associated water (dehydration). Formation water produced with oil is separated and disposed of.

The producing areas discussed in this report are located off the coasts of Louisiana, Texas, California, and Alaska. Leases have also been sold on acreage off Mississippi, Alabama, and Florida, and production is expected in these areas. The offshore areas are divided into those in state waters within the three mile limit and those beyond the three mile limit in Federal waters. The Federal waters are called the Outer Continental Shelf (OCS).

Table II-1 lists the historical totals for offshore production of oil and condensate. Table II-2 lists the natural gas production, and Table II-3 compares the offshore production with total U.S. production of oil and gas.

As shown in Table II-3, total oil production peaked in 1970 at 3.5 billion barrels and declined in 1973 to 3.4 billion barrels. While the OCS has a large potential for new production, 1971 saw a peak OCS production of 419 million barrels which declined to 395 million barrels in 1973. OCS production accounted for about 12% of total U.S. oil production for 1971, 1972, and 1973, up from 4.4% in 1964. Total U.S. gas production only increased from 20.7 trillion cubic feet in 1969 to 22.9 trillion cubic feet in 1973. The percent of OCS gas production increased from 9.4% to 14% over the same period.

In all of the states except Alaska, where there has been a jurisdictional dispute, the relative importance of the producing areas has moved from the state waters to the deeper OCS waters. Louisiana produced 429 million of the 583 million barrels of total offshore oil production and 3.6 trillion of the 3.9 trillion cubic feet of offshore gas production. Louisiana's oil production is 87% from OCS waters, while 21% of California's is from the OCS.

TABLE II-1

CRUDE OIL AND CONDENSATE PRODUCTION

TOTAL OFFSHORE "STATE" AND "FEDERAL OCS"
IN THOUSANDS OF BARRELS (M)

Year	ALASKA Barrels (M)	ALASKA Percent State	ALASKA Percent OCS	CALIFORNIA Barrels (M)	CALIFORNIA Percent State	CALIFORNIA Percent OCS	LOUISIANA Barrels (M)	LOUISIANA Percent State	LOUISIANA Percent OCS	TEXAS Barrels (M)	TEXAS Percent State	TEXAS Percent OCS	TOTAL Barrels (M)	TOTAL Percent State	TOTAL Percent OCS
PRIOR	-	-	-	422,385	100	-	54,803	98	2	-	-	-	477,188	100	-
1954	-	-	-	32,665	100	-	15,926	79	21	10	100	-	48,601	93	7
1955	-	-	-	33,252	100	-	25,731	74	26	156	99	1	59,139	89	11
1956	-	-	-	32,348	100	-	40,906	73	27	140	90	10	73,394	85	15
1957	-	-	-	30,561	100	-	52,835	70	30	256	98	2	83,652	81	19
1958	-	-	-	28,363	100	-	57,381	57	43	470	100	-	86,214	71	29
1959	-	-	-	26,787	100	-	72,793	51	49	499	100	-	100,079	64	36
1960	-	-	-	28,074	100	-	88,122	44	56	567	100	-	116,763	57	43
1961	-	-	-	29,887	100	-	103,197	38	62	292	100	-	133,376	52	48
1962	-	-	-	34,613	100	-	126,801	29	71	803	100	-	162,217	45	55
1963	-	-	-	38,346	100	-	149,087	30	70	669	92	8	188,102	44	56
1964	6	100	-	40,526	100	-	173,709	29	71	578	99	1	214,819	43	57
1965	30	100	-	42,772	100	-	199,293	27	73	557	99	1	242,652	40	60
1966	2,650	100	-	53,294	100	-	243,080	23	77	1,246	29	71	300,270	37	63
1967	15,937	100	-	64,807	100	-	284,033	23	77	3,400	16	84	368,177	40	60
1968	52,530	100	-	85,339	98	2	329,922	20	80	3,400	9	91	471,191	43	57
1969	60,887	100	-	96,145	90	10	365,691	18	82	3,109	11	89	525,832	41	59
1970	70,007	100	-	104,283	76	24	398,378	16	84	3,046	26	74	575,714	37	63
1971	66,152	100	-	101,717	69	31	444,363	13	87	2,885	42	58	615,117	32	68
1972	63,749	100	-	95,418	76	24	452,584	14	86	3,035	43	57	614,786	33	67
1973	61,715	100	-	89,218	79	21	429,465	13	87	3,018	46	54	583,416	32	68
Through 1973	393,663	100	-	1,510,800	93	7	4,108,100	24	76	28,136	40	60	6,040,699	46	54

SOURCE: Bureau of Mines, Alaska Scouting Service, Conservation Committee of California, Louisiana State Mineral Board, Louisiana Dept. of Conservation, Texas Railroad Commission. Louisiana and Texas are estimated in part.

TABLE II-2

NATURAL GAS PRODUCTION

TOTAL OFFSHORE "STATE" AND "FEDERAL OCS"
IN MILLIONS OF CUBIC FEET (MMCF)

Year	ALASKA			CALIFORNIA			LOUISIANA			TEXAS *			TOTAL		
	MMCF	Percent State	Percent OCS	MMCF	Percent State	Percent OCS	MMCF	Percent State	Percent OCS	MMCF	Percent State	Percent OCS	MMCF	Percent State	Percent OCS
PRIOR	-	-	-	-		-	91,675	78	22	-	-	-	91,675	78	22
1954	-	-	-	-		-	81,325	31	69	3,440	100	-	84,765	34	66
1955	-	-	-	-		-	121,279	33	67	6,880	100	-	123,159	37	63
1956	-	-	-	-		-	136,527	39	61	6,880	100	-	143,407	42	58
1957	-	-	-	-		-	160,472	49	51	13,765	100	-	174,237	53	47
1958	-	-	-	-		-	233,967	45	55	24,080	100	-	258,047	51	49
1959	-	-	-	-		-	329,280	37	63	24,080	100	-	353,360	41	59
1960	-	-	-	1,113	100	-	408,388	33	67	30,960	100	-	440,461	38	62
1961	-	-	-	5,903	100	-	458,481	31	69	13,760	100	-	478,144	33	67
1962	-	-	-	10,671	100	-	588,361	23	77	41,280	100	-	640,312	29	71
1963	-	-	-	25,769	100	-	706,545	20	80	30,960	100	-	763,274	26	74
1964	-	-	-	35,323	100	-	783,474	21	79	30,960	100	-	849,757	27	73
1965	10	100	-	40,770	100	-	871,124	26	74	27,520	100	-	939,424	31	69
1966	1,200	100	-	46,839	100	-	1,265,899	24	76	59,259	29	71	1,373,197	27	73
1967	8,324	100	-	46,732	100	-	1,655,223	34	66	127,473	22	78	1,837,752	35	65
1968	22,844	100	-	86,565	99	1	2,057,291	31	69	154,631	29	71	2,321,331	34	66
1969	44,393	100	-	81,326	94	6	2,478,745	26	74	240,212	47	53	2,844,676	31	69
1970	82,369	100	-	71,225	83	17	2,800,104	19	81	264,420	50	50	3,218,118	25	75
1971	83,750	100	-	60,484	74	26	3,219,200	18	82	387,245	67	33	3,750,679	26	74
1972	74,982	100	-	44,830	78	22	3,480,831	17	83	156,772	6	94	3,757,415	19	81
1973	72,526	100	-	37,581	81	19	3,614,892	15	85	159,000	6	94	3,883,999	17	83
Through 1973	390,398	100	-	595,131	91	9	25,543,083	23	77	1,803,577	48	52	28,332,189	27	73

SOURCE: Bureau of Mines, Alaska Scouting Service, Conservation Committee of California, Louisiana State Mineral Board, Louisiana Dept. of Conservation, Texas Railroad Commission.
Louisiana and Texas are estimated in part.

TABLE II-3

TOTAL UNITED STATES AND OUTER CONTINENTAL SHELF PRODUCTION OF CRUDE OIL & CONDENSATE, AND NATURAL GAS PERCENTAGE OF OCS PRODUCTION OF TOTAL U. S. PRODUCTION

Year	CRUDE OIL AND CONDENSATE PRODUCTION (Thousands of Bbls.) Total U.S.	Total OCS	OCS % of U.S.	GAS PRODUCTION (Millions of Cu.Ft.) Total U.S.	Total OCS	OCS % of U.S.
1953	2,357,082	1,151	.05 %	8,396,916	19,881	.24 %
1954	2,314,988	3,342	.14	[illegible],742,546	56,325	.64
1955	2,484,428	6,705	.27	[illegible],405,351	81,279	.86
1956	2,617,283	11,015	.42	10,081,923	82,893	.82
1957	2,616,901	16,070	.61	10,680,258	82,574	.77
1958	2,448,987	24,769	1.01	11,030,298	127,693	1.16
1959	2,574,590	35,698	1.39	11,619,951	207,156	1.78
1960	2,574,933	49,666	1.93	12,771,038	273,034	2.14
1961	2,621,758	64,330	2.45	13,254,025	318,280	2.40
1962	2,676,189	89,737	3.35	13,876,622	451,953	3.26
1963	2,752,723	104,579	3.80	14,666,559	564,353	3.85
1964	2,786,822	122,500	4.40	15,462,143	621,731	4.02
1965	2,848,514	144,969	5.09	16,039,753	645,589	4.03
1966	3,027,763	188,714	6.23	17,206,628	1,007,447	5.86
1967	3,215,742	221,862	6.90	18,171,325	1,187,216	6.53
1968	3,329,042	268,996	8.08	19,322,400	1,524,178	7.89
1969	3,371,751	312,860	9.28	20,698,240	1,954,487	9.44
1970	3,517,450	360,646	10.25	21,920,642	2,418,677	11.03
1971	3,453,914	418,549	12.12	22,493,000	2,777,043	12.35
1972	3,455,000	411,886	11.92	22,532,000	3,038,555	13.49
1973	3,356,000	394,730	11.76	22,900,000	3,211,588	14.02

SOURCE: Total United States Production - MINERALS YEARBOOK and Mineral Industry Surveys, Bur. of Mines. 1973 Total United States Production data are preliminary and subject to change.

1.3. Demand for Oil and Gas

It is not the intention of this report to analyze in detail future energy demand or supply for the U.S. The report will draw from the work of reputable sources to broadly sketch the likely demand for oil and gas over the period of interest. The estimates will then be used as the background for estimating the impact of the proposed pollution control requirements on the offshore and onshore industry.

The principal conclusion coming from an examination of the U.S. demand for crude oil and the available supply is that demand is and will likely continue to exceed domestic production under most realistic scenarios. The total demand for crude oil has grown at about 4.5% per year over the period 1965-1973. This growth, combined with a slow decline in U.S. production since 1970, has resulted in an increasing reliance on imports of both crude oil and refined products. Growth in domestic refining capacity has been less than the growth in U.S. consumption of refined products. The difference has been made up by importing products from foreign refineries; in 1973, product imports approximated 17% of total product consumption and were also 46% of both crude and product imports.

Domestic gas production has historically approximated consumption and domestic supplies have not been sufficient for several years. As a result, imports are expected to grow to over 10% of consumption by 1985.[1]

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[1] Project Independence Blueprint, Final Task Force Report-Finance, p. 66, FEA, November 1974.

Note that the growth in natural gas usage averaged about 6.5% per year from 1965 through 1970. Annual growth following 1970 has been about 2.5%. U.S. production increased by about 1% per year from 1970 through 1973. The difference has been made up by imports which accounted for about 7% of consumption in 1974.

1.4. Oil and Gas Supply/Demand

Petroleum and natural gas are primarily consumed as fuels. Prior to 1973, these energy forms and others were relatively inexpensive in the United States. The combined effects of industry practices and government tax and pricing measures served to keep energy prices low. The measures encouraged gas consumption.

In the last 25 years, there has been a shift from a significant dependence on coal to meet the U.S. energy demand to a predominant dependence on oil and natural gas. Table II-4 lists the components of U.S. energy demand for 1970 and 1972. Oil was the primary source of 45.5% of energy consumed in 1972. Natural gas accounted for 32.3%. In 1950, coal accounted for 37% of U.S. energy consumption, but coal's share had fallen to 18% in 1974.

With energy prices low, energy consumption has been regarded as relatively price inelastic, particularly in the short run. However, the 1973-1974 oil embargo, the rise in imported petroleum prices, and current interest in energy conservation have highlighted the complex nature of the energy demand function. Energy consumption depends in a vital way on a multitude of factors other than the short-run cost of producing the

TABLE II- 4

U.S. ENERGY DEMAND BY PRIMARY SOURCE - 1972 and 1970

Energy Form	1972		1970	
Oil				
Quadrillion Btu /year	32.8	(45.5%)	29.6	(44.1%)
MM bbl/day	16.5		14.6	
Gas				
Quadrillion Btu /year	23.3	(32.3%)	22.0	(32.7%)
Trillion cubic feet/year	22.6		21.4	
Coal				
Quadrillion Btu/year	12.5	(17.2%)	12.7	(18.9%)
MM Tons /year	517		532	
Nuclear				
Quadrillion Btu /year	0.6	(0.8%)	0.2	(0.3%)
Hydro and Other				
Quadrillion Btu /year	2.9	(4.2%)	2.7	(4.0%)
Total				
Quadrillion Btu /year	72.1	(100%)	67.2	(100%)

SOURCE: U.S. Bureau of Mines , cited in Project Independence Blueprint, Final Task Force Report - Finance, p. A-7, FEA, November 1974 energy. Use of public transportation, living standards, building codes, driving habits, land use planning, home heating habits, and industrial processes are only a few of the factors affecting energy demand. Many of these factors are a reflection of the long-run price of energy but are not readily changed in the short run. It is also clear that political considerations will be an important factor in determining both total energy usage and the relative use of various energy forms.

Prior to the embargo, total energy consumption was growing at 4.3% per year. This growth has since been reduced to 3.2% to 3.5% per year. There was an actual decline of 2% in 1974, but there is no expectation of a permanent decline trend in the foreseeable future. The growth rate may be temporarily or permanently lower, but there will be a continuing and growing demand for new energy.

In the case of petroleum, there is the potential for some substitution away from oil, such as the conversion of electric power plants to coal. There is also some potential for an absolute reduction in petroleum/energy usage in transportation; smaller cars and public transportation at least present this possibility. However, at best, the expectation is for growth in oil demand to be held very low but not to decline. Since 1970, all of the growth in U.S. oil demand has been met by imported oil. The Project Independence Report examined the potential for reducing the level of oil imports and concluded that if there were strong government action to accelerate domestic production and conservation and if world oil prices were $11 per barrel, it would be possible to end imports by about 1985. At lower prices and with less vigorous government action, some level of imports would still be required in 1985.

The continuing flow of imported oil at least to 1985 at prices likely to be well in excess of production costs of all but marginal domestic production will prevent even relatively large increases in the costs of domestic production from acting to reduce demand for the domestic crude below domestic production capacity. Either increases or decreases in total U.S. petroleum demand will mean changes in the level of imports, not the level of U.S. petroleum production. This pattern will be particularly true for wells which are now in production. Some individual wells which are now high cost producers will be made uneconomical by the higher production cost resulting from pollution control requirements. Short of domestic discoveries of unprecedented magnitude and productivity, the demand for domestically produced oil will continue to be well in excess of U.S. production capacity.

A similar situation is seen in the case of natural gas. There is long-term potential for some substitution away from gas, for example, to nuclear power and coal for electric power generation. Imports are not yet as important a factor as in oil, since the volume is not as great.

Unlike oil, interstate gas is usually sold under long-term contracts at regulated prices,which at present are low relative to the costs of developing new gas wells or of close substitutes like oil. Interstate natural gas prices were (1974) 1/3 to 1/4 of the price of fuel oil prices per BTU in major natural gas consuming areas. Since the price of natural gas is presently well below the next most expensive substitute, it is unlikely that even relatively large pollution control costs, by themselves, would have the effect of shifting demand away from gas to substitute products. The overall demand for natural gas will thus not be reduced below U.S. supply capacity. However, the supply might be affected if some individual wells were made uneconomical as a result of higher pollution control costs.

Many estimates have been made of the future demand and supply of oil and gas. For this study, the estimates made in the Project Independence Blueprint Report, November 1974, have been used. The report presents a series of estimates under different sets of assumptions. The assumptions include different levels of government efforts to encourage energy conservation, to accelerate domestic energy production, and the level of OPEC[1] oil prices. The report makes clear that there are both choices and uncertainties. The oil and gas estimates are used in this report in that light.

The report constructed a set of estimates for a "base case" and "accelerated supply case" under both a $7 and $11 per barrel world oil price. Table II- 5 lists the estimated U.S. energy demand by form, with imported oil reported separately. The base case assumed that government policy towards energy, and particularly petroleum production, will be essentially unchanged. Leasing on the Outer Continental Shelf (OCS) will remain at about 2-3 million acres per year. Government royalties for

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[1] Organization of Petroleum Exporting Countries, including Saudi Arabia, Iran, Venezuela, Nigeria, Libya, Kuwait, Iraq, United Arab Emirates, Algeria, Indonesia, Qatar, Ecuador and Gabon, which is an associate member. The United Arab Emirates is a federation of Abu Dhabi, Dubai, Sharjah, Ajman, Umm al Quwain, Ras Al Khaimah and Fujairah.

TABLE II-5

U.S. ENERGY DEMAND BY PRIMARY SOURCE - 1985

(Quadrillion Btu's)

		1985			
		$7 Oil		$11 Oil	
Energy Form	1972	Base Case	Accelerated Supply	Base Case	Accelerated Supply
U.S. Oil	22.4	23.1	30.5	31.3	38.0
Imported Oil	11.7	24.8	17.1	6.5	0.0
Gas	22.1	23.8	24.7	24.8	25.5
Coal	12.5	19.9	17.7	22.9	20.7
Hydro & Geo.	2.9	4.8	4.8	4.8	4.8
Nuclear	0.6	12.5	14.7	12.5	14.7
Synthetics	-	-	-	-	0.4
Total	72.1	109.1	109.6	102.9	104.2

SOURCE: Project Independence Report, FEA, November 1974, p. 46

the leases would remain at one-sixth. Natural gas for interstate sale would be regulated at $0.89 per thousand cubic feet. Under the "accelerated development" case, leasing would be increased to 10 million acres per year, and royalties would be reduced to one-eighth. Natural gas price regulations would be ended, with prices rising to $1.75 per thousand cubic feet by 1988. Development would also be allowed in the Naval petroleum reserves.

The values in Table II-5 reflect FEA's estimate (based on $7/bbl crude) of long-term growth rate of U.S. energy consumption (3.1%/year). At oil prices of $11 per barrel, the annual energy growth rate was estimated to be 2.9%. There is some shift away from oil to gas and coal, but not a significant reduction in overall energy demand. The projection of such reductions from the historic growth rate of 4.3% are an important uncertainty in the analysis.

Table II-6 is a more detailed listing of U.S. oil production estimates with the additional estimate of production levels if the world price dropped to $4 per barrel. In all cases, domestic production would continue to decline out to 1977. Table II-7 lists the estimated sources of new U.S. oil production if the world oil price is $11 per barrel. Offshore production amounts to 2.9 million barrels per day, or 19% of the total U.S. production, under the "business as usual" (base case) scenario in 1985. New OCS production is 4.8 million barrels per day (24%) under the accelerated development case.

Table II-8 lists the estimated gas production assuming the $11 per barrel world oil price and accelerated development. The report saw very

TABLE II-6

U.S. CRUDE OIL PRODUCTION - 1974 TO 1985

(millions barrels per day)

"Business as Usual" Case

World Price ($/bbl)	1974	1977	1980	1985
4	10.5	9.0	9.3	9.8
7	10.5	9.5	11.1	11.9
11	10.5	9.9	12.2	15.0

"Accelerated Development" Case

World Price ($/bbl)	1974	1977	1980	1985
4	10.5	9.7	11.1	11.6
7	10.5	10.2	12.9	16.6
11	10.5	10.3	13.5	20.0

SOURCE: Project Independence Report, FEA, November 1974, p. 81

TABLE II- 7

POTENTIAL RATES OF U.S. OIL PRODUCTION

(millions of barrels per day, at $11 per barrel world prices)

	Production Area	1974	1985 "Business As Usual"	(change)	1985 "Accelerated Development"	(change)
1.	Onshore - Lower 48 States	8.9	9.1	(1.2)	9.9	(1.0)
	- Conventional fields and new primary fields	6.4	3.4	(-3.0)	3.5	(-2.9)
	- New secondary	-	2.4	(2.4)	2.4	(2.4)
	- New tertiary	-	1.8	(1.8)	2.3	(2.3)
	- Natural gas liquids	2.0	1.5	(-0.5)	1.6	(-0.4)
	- Naval Petroleum Reserve #1	-	-		0.2	(0.2)
2.	Alaska	0.2	3.0	(2.8)	5.3	(5.1)
	- North Slope	-	2.5	(2.5)	2.5	(2.5)
	- Southern Alaska (including OCS)	0.2	0.5	(0.3)	0.8	(0.6)
	- Naval Petroleum Reserve #4	-	-		2.0	(2.0)
3.	Lower 48 Outer Continental Shelf	1.4	2.6	(1.2)	4.3	(2.9)
	- Gulf of Mexico	1.3	2.1	(0.8)	2.5	(1.2)
	- California OCS	0.1	0.5	(0.4)	1.3	(1.2)
	- Atlantic OCS	-	-		0.5	(0.5)
4.	Heavy Crude and Tar Sands	-	0.3	(0.3)	0.5	(0.5)
	Total Potential Production	10.5	15.0	(4.5)	20.0	(9.5)

SOURCE: Project Independence Report, FEA, November 1974, p. 83

TABLE II-8

U.S. NATURAL GAS SUPPLIES, 1972-1985*

(trillions of cubic feet per year)

Source	1972	1977	1980	1985
Lower 48 States, Onshore	19.4	16.7	17.4	15.5
Lower 48 States, Offshore	3.0	4.4	6.1	8.2
Alaska (except North Slope)	0.08	0.02	0.03	0.1
Naval Petroleum Reserve #4	0.0	0.0	0.0	0.8
North Slope	0.0	0.0	0.8	2.5
Coal Conversion	0.0	0.0	0.0	0.2
TOTAL	22.5	21.1	24.3	27.3

*Assumes $11 per barrel world oil prices and accelerated development scenario.

SOURCE: Project Independence Report, FEA, November 1974, p. 48

limited potential for U.S.-produced gas to maintain its present share of energy consumption. Offshore production is estimated to account for 31% of gas production in 1985 under an accelerated development assumption, as compared with 13% in 1972.

The essential conclusion from an examination of the supply and demand forecasts for oil and gas out to 1985 is that even relatively large increases in the cost of producing domestic crude and gas will not result in a reduction of demand below the capacity of U.S. production at $7 or $11 per barrel price levels.

To illustrate the role of imports in the relationship between U.S. oil supply and demand, Figure II-1A was constructed from the crude oil supply and demand estimates in the Project Independence Report. An imports supply curve has been drawn showing that at $11 per barrel, at least 5 MM bbl/day can be purchased but none can be purchased for less than $11 per barrel. With a supply/demand relationship as shown in Figure II-1 , a shift in the U.S. supply curve as a result of an industry-wide change in production economics, such as resulting from new pollution control costs, will not change the intersection of the total U.S. supply curve and the U.S. demand curve. The total quantity of oil consumed will remain essentially unchanged, as would the price. The difference between total demand and available U.S. supply would be made up by imports. Thus, the demand for U.S. production at the equilibrium price of $11 per barrel would remain both unchanged and greater than U.S. production capacity at $11 per barrel.

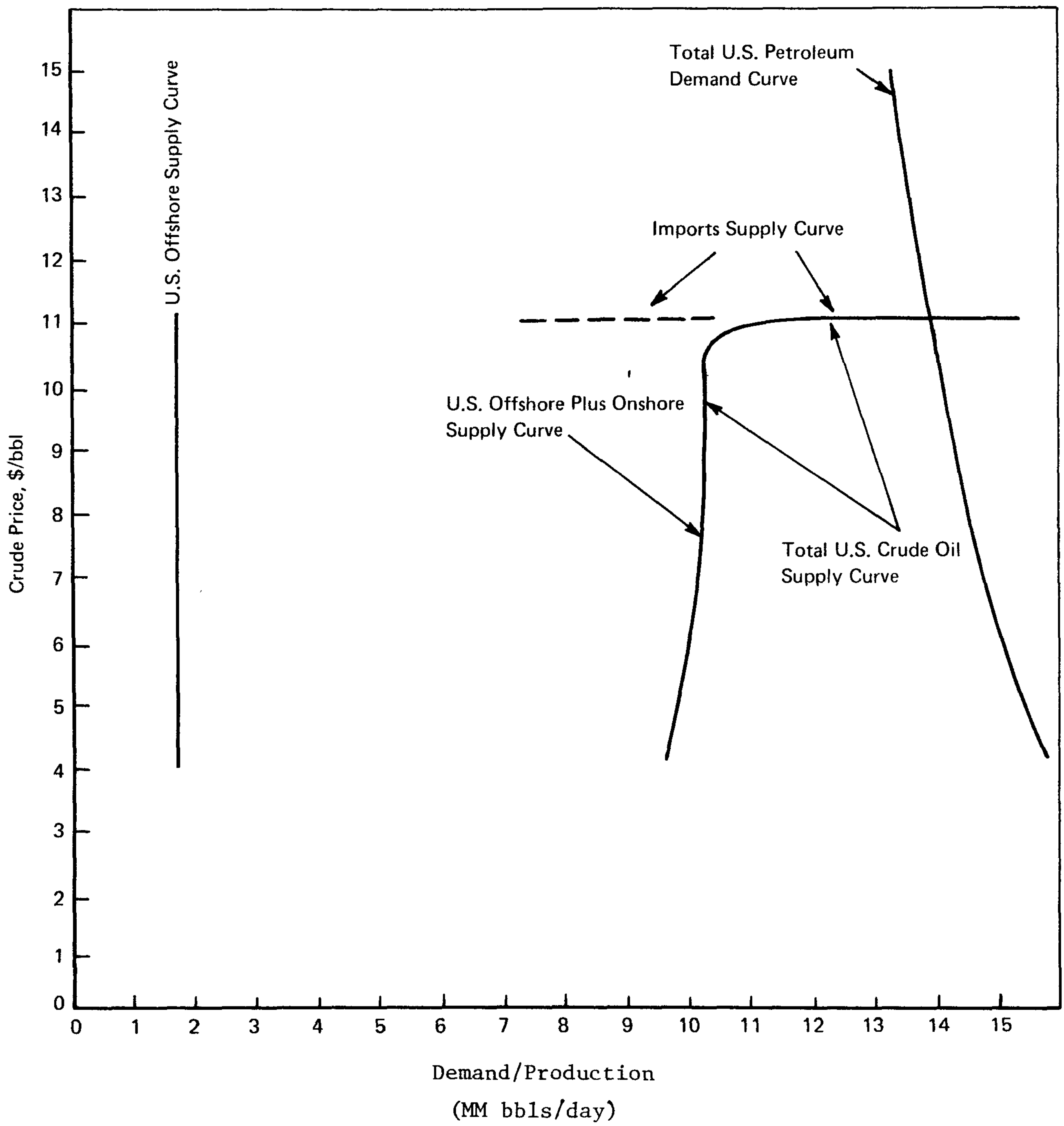

FIGURE II-1 1977 U.S. PETROLEUM SUPPLY AND DEMAND FUNCTIONS
(Accelerated Development Scenario)

<u>SOURCE:</u> Drawn from projected supply and demand values in <u>Oil: Possible Levels of Future Production</u>, <u>Project Independence Blueprint</u>, FEA, Nov. 1974

Figure II-1 also shows the domestic supply curve to be almost vertical above \$9 per barrel. Increasing prices from \$9 to \$11 per barrel will increase total U.S. production by only a small amount in 1977, according to the Blueprint estimate shown in the figure. While a shift in the U.S. supply curve as mentioned above will result in lower U.S. oil production (to be made up by imports), the nearly vertical U.S. supply curve suggests that the production losses will be small for production cost increases as large as \$2 per barrel.

II.2. CHARACTERIZATION OF OFFSHORE OIL AND GAS PRODUCING COMPANIES

Until the early 1970's, the vast majority of U.S. offshore oil and gas production came from wells owned and operated by the large integrated oil companies. The large "up front" costs of lease bonus payments and the massive investments required for exploration, development, production, and processing facilities tended to discourage all but the largest firms from undertaking offshore projects. Table II- 9 shows the participation of the major oil companies in offshore production in 1971; in that year, the major integrated companies operating independently or in groups accounted for 97% of OCS oil production. Recent efforts have been made by the Interior Department to allow more participation by smaller companies. Since 1971, there has been an increased participation by the independents in acquiring offshore acreage. For the three lease sales of September and December 1972 and June 1973, single majors acquired 21% of the acreage, groups of majors acquired 14%, single independents acquired 17%, and groups of independents and majors acquired 47% of the acreage.

The companies attempting to acquire offshore acreage for oil and gas development bid either independently or in groups for the right to develop and produce the fields. If a consortium of companies wins the bidding, one of the firms will be responsible for drilling and operating the wells. Table II-10 lists, as an example, the ownership relationship of the firms operating in Federal waters off Louisiana in 1973. Table II-11 lists major oil companies and their partners owning leases in Louisiana state waters the same year.

TABLE II-9

OCS LEASE ACREAGE AND PRODUCTION, THROUGH SEPT. 1971

Lessee	Acreage (%)	Production (%)
Individual Majors	46	63
Groups of Majors	35	34
Groups of Independents	17	2
Individual Independents	2	1

SOURCE: U.S. Department of the Interior, reported in Outer Continental Shelf Policy Issues, p. 61, Committee on Interior and Insular Affairs, U.S. Senate, 1972

TABLE II-10

—LOUISIANA LAND & EXPLORATION CO., DOCKET NO CI73-501, JOINT OWNERSHIP OF FEDERAL OFFSHORE PRODUCING LEASES

Company	Number of leases	Independently owned	Major partners	Number of joint ventures[1]
The majors:				
Amerada-Hess	15	0	Marathon	13
			Signal	14
			Louisiana Land	14
Atlantic-Richfield	94	3	Cities	85
			Getty	83
			Continental	87
			Tenneco[2]	4
			Standard Oil of California (Chevron)	2
			El Paso[2]	2
Cities Service	101	1	Atlantic	85
			Getty	93
			Continental	91
			Mobil	2
			Tenneco[2]	7
			Standard Oil of California (Chevron).	2
Continental	119	1	Atlantic	87
			Cities	91
			Getty	87
			Mobil	19
			Tenneco[2]	8
			Standard Oil of California (Chevron).	2
			Superior	2
			Transocean	2
			Southern Natural[2]	2
Getty	100	2	Atlantic	83
			Cities	93
			Continental	87
			Mobil	8
			Tenneco[2]	4
			Standard Oil of California (Chevron).	3
			Phillips	3
			Superior	2
			Transocean	2
			Southern Natural[2]	2
			Allied Chemical	3
Gulf	51	34	Mobil	7
			Standard Oil of New Jersey (Exxon).	6
			Phillips	4
			Kerr-McGee	2
Marathon	18	0	Amerada	13
			Signal	13
			Louisiana Land	13
			Union	5
			Sun	3
Mobil	52	6	Continental	19
			Cities	8
			Getty	8
			Gulf	7
			Standard Oil of California (Chevron)	5
			Standard Oil of New Jersey (Exxon).	4
			Standard Oil of Indiana (Amoco).	4
			Pennzoil[2]	2
Phillips	16	3	Kerr-McGee	7
			Gulf	4
			Getty	3
			Standard Oil of Indiana (Amoco).	3
			Sun	3
			Southern Natural[2]	2
			Allied Chemical	3
Shell	68	64	Standard Oil of California (Chevron).	2
Chevron	105	86	Mobil	5
			Getty	3
			Atlantic	2
			Cities	2
			Continental	2
Amoco	60	3	Texaco	29
			Union	12
			Southern Natural[2]	8
			Mobil	4
			Kerr-McGee	4
			Superior	4
			Tenneco[2]	3
			Phillips	3
			Pennzoil[2]	4
			Texas Eastern[2]	2
Exxon	52	43	Gulf	6
			Mobil	4
Sun	19	0	Burmah	11
			Murphy	10
			Kerr-McGee	4
			Union	3
			Phillips	3
			Marathon	3
			Cabot	3
			Diamond Shamrock	3
			Anadarko[2]	3
Texaco	55	16	Standard Oil of Indiana (Amoco)	29
			Tenneco[2]	9
Union Oil	37	18	Standard Oil of Indiana (Amoco).	12
			Marathon	5
			Superior	4
			Sun	3
			Texas Eastern[2]	2

TABLE II-10 (Con't)

–LOUISIANA LAND & EXPLORATION CO. DOCKET NO CI73-501, JOINT OWNERSHIP OF FEDERAL OFFSHORE PRODUCING LEASES—Continued

Company	Number of leases	Independently owned	Major partners	Number of joint ventures [1]
Selected medium sized firms.				
Tenneco Oil [2]	51	24	Texaco	9
			Continental	8
			Cities	7
			Consolidated [2]	6
			Columbia Gas [2]	6
			Texas Gas Transmission [2]	6
			Forest	6
Kerr-McGee	29	0	Phillips	7
			Cabot	12
			Southern Nat [2]	8
Cabot Corp	12	0	Sun	3
			Kerr-McGee	12
Pennzoil [2]	9	1	Standard Oil of Indiana	4
Consolidated [2]	33	0	Columbia Gas	26
			Texas Gas Transmission [2]	25
			Forest	26
			Tenneco [2]	6
Columbia Gas [2]	33	0	Consolidated [2]	26
			Texas Gas [2]	27
			Forest	33
			Tenneco [2]	6
Texas Gas [2]	28	0	Consolidated [2]	25
			Columbia Gas [2]	26
			Forest	23
			Tenneco [2]	6
Forest Oil	34	0	Consolidated [2]	28
			Columbia Gas [2]	37
			Texas Gas [2]	26
			Tenneco [2]	8
Murphy-Ocean	32	1	Sun	10
			Burmah	21
Burmah	23	0	Sun	11
			Murphy-Ocean	21
Signal	15	1	Amerada	14
			Marathon	13
			Louisiana Land	14
Louisiana Land & Exploration	14	0	Amerada	14
			Marathon	13
			Signal	14
Superior	21	10	Standard Oil of Indiana (Amoco)	4
			Union	4
			Transocean	7
Transocean	14	0	Superior	7
			Hunt	7
			Placid	7
			Ashland	7
Hunt	17	3	Transocean	7
			Placid	9
			Ashland	7
Ashland	7	0	Transocean	7
			Hunt	7
			Placid	7
Southern Natural [2]	15	0	Standard Oil of Indiana (Amoco)	8
			Kerr-McGee	8
Allied Chemical	3	0	Getty	3
			Phillips	3
Anadarko [2]	3	0	Sun	3
			Diamond Shamrock	3
Diamond Shamrock	4	0	Sun	3
			Anadarko [2]	3
Texas Eastern [2]	2	0	Standard Oil of Indiana (Amoco)	2
			Union	2
El Paso [2]	2	0	Atlantic	2
Placid	15	0	Transocean	7
			Hunt	9
			Ashland	7

[1] May add to more than total number of leases when 3 or more firms participate in individual joint ventures.
[2] This company or an affiliate is a major interstate gas pipeline

SOURCE: U.S. Dept. of the Interior, cited in Market Performance and Competition in the Petroleum Industry, p. 1165, Committee on Interior and Insular Affairs, U.S. Senate, 1974

TABLE II-11

. —LOUISIANA LAND & EXPLORATION CO., DOCKET NO C173-501

JOINT OWNERSHIP OF STATE OF LOUISIANA PETROLEUM LEASES BY LARGE MAJOR PRODUCERS

Company, major partners, and jointly held State leases.	Number
Amerada-Hess.	
Phillips	36
Amoco	10
Sohio	2
Atlantic-Richfield.	
Cities	27
Continental	28
Getty	26
Union	10
Marathon	7
Texaco	4
Tenneco	4
Amoco	3
Chevron	2
Sohio	2
Cities Service	
Atlantic	27
Continental	27
Getty	31
Exxon	2
Continental.	
Atlantic	28
Cities	27
Getty	27
Mobil	16
Exxon	13
Amoco	11
Sun	11
Tenneco	3
Gulf	3
Getty:	
Gulf	51
Atlantic	26
Cities	31
Continental	27
Exxon	27
Sohio	4
Tenneco	4
Amoco	4
Mobil	3
Sun	3
Shell	2
Texaco	2
Gulf	
Exxon	62
Getty	51
Sohio	13
Shell	12
Amoco	7
Texaco	6
Chevron	6
Tenneco	5
Mobil	5
Continental	3
Sun	3
Phillips	2
Amerada	2
Marathon·	
Atlantic	7
Tenneco	3
Mobil.	
Continental	16
Amoco	8
Gulf	5
Sun	4
Texaco	4
Tenneco	3
Getty	3
Exxon	2
Phillips:	
Amerada	36
Sun	7
Amoco	3
Gulf	2
Shell:	
Gulf	12
Chevron	8
Exxon	5
Amoco	5
Texaco	5
Getty	2
Chevron:	
Shell	8
Gulf	6
Texaco	3
Exxon	3
Atlantic	3
Amoco·	
Texaco	11
Continental	11
Amerada	10
Mobil	8
Gulf	7
Shell	5
Sun	5
Tenneco	5
Exxon	4
Getty	4
Atlantic	3
Phillips	3
Union	3
Exxon·	
Gulf	62
Getty	27
Continental	13
Texaco	11
Tenneco	5
Shell	5
Amoco	4
Chevron	3
Mobil	2
Cities	2
Union	2
Sohio:	
Gulf	13
Getty	4
Atlantic	2
Amerada	2
Sun.	
Continent 1	11
Phillips	7
Amoco	5
Mobil	4
Getty	3
Gulf	3
Tenneco	3
Union	3
Tenneco	
Exxon	5
Amoco	5
Gulf	5
Atlantic	4
Getty	4
Continental	3
Marathon	3
Mobil	3
Sun	3
Texaco:	
Exxon	11
Amoco	11
Gulf	6
Shell	5
Mobil	4
Atlantic	4
Chevron	3
Getty	2
Union	2
Union Oil:	
Atlantic	10
Amoco	3
Sun	3
Exxon	2
Texaco	2

SOURCE: U.S. Dept. of the Interior, cited in Market Performance and Competition in the Petroleum Industry, p.1167, Committee on Interior and Insular Affairs, U.S. Senate, 1974

Besides the major integrated oil companies, the largest group of offshore participants are the interstate gas pipeline companies. Tables II-12, II-13, and II-14 list the major pipeline operators and show their 1972 participation in the lease bidding. In the December 19, 1972, bidding on Federal OCS acreage off Louisiana, pipeline companies participated in 51.7% of the successful bids and paid 19.5% of the bonuses.

On February 21, 1975, the Interior Department published a proposed regulation in the Federal Register that no companies producing more than 1.6 million barrels a day of crude oil, natural gas (equivalent), and natural gas liquids could jointly bid with other such companies on OCS leases. The intent of the regulation is to further reduce the dominance of the major oil companies in offshore production.

TABLE II-12

-LOUISIANA LAND AND EXPLORATION CO., DOCKET NO. C173-501—MAJOR INTERSTATE GAS PIPELINES AND THEIR PRODUCING AFFILIATES

Interstate pipeline companies	Exploration, development, and producing affiliates
Arkansas Louisiana Gas Co	Arkla Exploration Co.
Cities Service Gas Co	Cities Service Oil Co., Cities Service Gas Resources Co., Hydrocarbon Production Co., Inc.
Colorado Interstate Gas Co	Coastal States Gas Producing Co., LO-VACA Gathering Co, Colorado Oil and Gas Corp., Nueces Industrial Gas Co.
Columbia Gas Transmission Corp	Columbia Gas Development Corp.
Consolidated Gas Supply Corp	CNG Producing Co.
El Paso Natural Gas Co	Odessa Natural Gasoline Co., Odessa Natural Corp., Trebol Drilling Co., Pecos Co.
Florida Gas Transmission Co	Florida Gas Exploration Co.
Lone Star Gas Co	Lone Star Producing Co.
Michigan Wisconsin Gas Co	American Natural Gas Production Co.
Natural Gas Pipeline Co. of America	Harper Oil Co.
Northern Natural Gas Co	(Produces under its own name)
Panhandle Eastern Pipeline Co	Anadarko Production Co., Pan Eastern Exploration Co., Panhandle Western Gas Co.
Southern Natural Gas Co	SONAT Exploration Co., The Offshore Co.
Tennessee Gas Transmission Co	Tenneco Oil Co.
Tennessee Gas Pipeline Co	Tenneco Exploration, Ltd., Tenneco Offshore Co, Inc., Tenneco West, Inc.
Texas Eastern Transmission Corp	La Gloria Oil and Gas Co, Texas Eastern Gas Supply Co., Texas Eastern Maroc, Inc., Texas Eastern Exploration Co., Texas Eastern Oil Co.
Texas Gas Transmission Corp	Texas Gas Exploration Corp.
Transcontinental Gas Pipeline Corp	Transcontinental Production Co., Trans-Gulf Transmission Corp.
Transwestern Pipeline Co [1]	Transwestern, Inc., Transwestern Gas Supply Co.
Trunkline Gas Co. [2]	
United Gas Pipeline Co	Pennzoil Producing Co., Pennzoil Petroleums, Ltd, Pennzoil Louisiana & Texas Offshore, Inc., Pennzoil Offshore Gas Operator, Inc.

[1] Subsidiary of Texas Eastern Transmission Corp.
[2] Subsidiary of Panhandle Eastern Pipeline Co.

SOURCE: U.S. Dept. of the Interior, cited in Market Performance and Competition in the Petroleum Industry, p. 1170, Committee on Interior and Insular Affairs, U.S. Senate, 1974

TABLE II-13

-PARTICIPATION BY INTERSTATE PIPELINE COMPANY AFFILIATES IN OFFSHORE LOUISIANA FEDERAL OIL AND GAS LEASE SALE, SEPT. 12, 1972

Interstate pipeline affiliation/bidding group	Successful bids (number of leases)	Bonuses paid by pipeline affiliate (dollars)	Pipeline affiliates' percent of bonuses paid (range)
Texas Eastern Transmission Corp.. Texas Eastern Exploration Co ,[1] Amoco Production Co , Union Oil Co of California	21	19, 523, 520	24–36
Cities Service Gas Co : Cities Service Oil Co.,[1] Tenneco Oil Co ,[1] Continental Oil Co , Getty Oil Co	2	1, 993, 685	33–34
Tennessee Gas Pipeline Co Tenneco Oil Co ,[1] Cities Service Oil Co.,[1] Texaco, Inc , Continental Oil Co	4	6, 568, 143	33–50
United Gas Pipe Line Co : Pennzoil Offshore Gas Operators,[1] Pennzoil L & T. Offshore, Inc.,[1] Gulf Oil Corp . Mobil Oil Corp	4	30, 039, 200	7–13
United Gas Pipe Line Co · Pennzoil Offshore Gas Operators,[1] Pennzoil L & T Offshore, Inc ,[1] Mesa Petroleum Co., Burmah Oil Dev , Inc , Canadian Occidental Ca., Inc	1	4, 532, 792	15
Florida Gas Transmission Co. Florida Gas Explor. Co.,[1] Shell Oil Co., Sabine Explor Corp , Drillamex, Inc., Kirby Petroleum Co., Royal Gorge Co., American Independent Oil Co	1	747, 600	12
Consolidated Gas Supply Corp.. Consolidated Gas Supply Corp.,[1] Aztec Oil and Gas Co	1	191, 925	50
Total pipeline affiliates' successful bids	33	63, 596, 865	
Percent of total successful bids	53. 2	10. 8	

[1] Corporate affiliate of interstate pipeline company.

Source: Bid recap sheets, Bureau of Land Management, Department of the Interior, oil and gas lease sale, offshore Louisiana, Sept. 12, 1972.

cited in Market Performance and Competition in the Petroleum Industry, p. 1170, Committee on Interior and Insular Affairs, U.S. Senate, 1974

TABLE II-14

—PARTICIPATION BY INTERSTATE PIPELINE COMPANY AFFILIATES IN OFFSHORE LOUISIANA FEDERAL OIL AND GAS LEASE SALE, DEC. 19, 1972

Interstate pipeline affiliation/bidding group	Successful bids (number of leases)	Bonuses paid by pipeline affiliate (dollars)	Pipeline affiliates' percent of bonuses paid (range)
Columbia Gas Transmission Co	7	80,015,311	40
Columbia Gas Development Corp.[1]			
Forest Oil Corp.			
Energy Ventures, Inc.			
Consolidated Gas Supply Corp	7	24,321,180	25-34
CNG Producing Co.[1]			
Amoco Production Co.			
The NW Mutual Life Ins. Co.			
Cities Service Gas Co	16	47,453,678	25-50
Cities Service Oil Co.[1]			
Getty Oil Co.			
Continental Oil Co.			
Atlantic Richfield Co.			
Southern Natural Gas Co	1	7,038,899	28
Sonat—Exploration Co.[1]			
The Offshore Co.			
Midwest Oil Co.			
Newmont Oil Co.			
Southland Royalty Co.			
Samedan Offshore Co.			
Champlin Petroleum Co.			
Trans Continental Gas Pipe Line Corp	13	53,418,570	19-25
Trans-Continental Prod. Co.[1]			
Shell Oil Co.			
Texas Eastern Transmission Corp	6	20,582,750	14-33
Texas Eastern Exploration Co.[1]			
Louisiana Land and Explor. Co.			
Signal Oil & Gas Co.			
Marathon Oil Co.			
United Gas Pipe Line Co	3	15,501,506	7-27
Pennzoil Offshore Gas Operators[1]			
Pennzoil L. & T. Offshore, Inc.[1]			
Mobil Oil Corp.			
Chevron Oil Co.			
Texas Production Co.			
United Gas Pipe Line Co	1	20,903,880	7-27
Pennzoil Offshore Gas Operators[1]			
Pennzoil L. & T. Offshore, Inc.[1]			
Mesa Petroleum Co.			
Burmah Oil Dev., Inc.			
Texas Production Co.			
Tennessee Gas Pipeline Co	6	55,147,808	50
Tenneco Exploration, Inc.[1]			
Texaco, Inc.			
Total—pipeline affiliates' successful bids	60	324,383,582	
Percent of total successful bids	51.7	19.5	

[1] Corporate affiliate of interstate pipeline company.

Source: Bid recap sheets, Bureau of Land Management, Department of the Interior, Oil and Gas Lease Sale—Offshore Louisiana—December 19, 1972.

cited in Market Performance and Competition in the Petroleum Industry, p. 1171, Committee on Interior and Insular Affairs, U.S. Senate, 1974

II.3. OIL AND GAS PRICING

3.1. Crude Oil Pricing

The Role of Crude Prices in the Economic Impact Analysis

The price of crude oil and the factors and processes which determine its price have undergone dramatic changes in the last few years. While oil from different fields has distinct physical and chemical properties, it can be characterized by and large as a world commodity product. As such, its price should be subject to the movements of world supply and demand. However, the political implications of crude prices and crude sources have strongly distorted prices even before the recent embargo.

The price which operators of domestic oil wells can receive for their crude is a critical element in determining the impact of the proposed effluent limitation guidelines. At sufficiently high prices, there would simply be no potential for the pollution control costs making an existing well unprofitable. Yet the uncertainty about U.S. crude prices over the period when the guidelines will become effective, 1977-1983, is an unresolvable unknown.

At present (January 1975), prices for U.S. "old" crude are frozen at $5.25 per barrel while "new", released, and stripper well crude prices are uncontrolled. However, there is a major public policy debate in progress concerning the pricing of domestic crude. The argument is being made that all price controls should be removed in order to accelerate the development of domestic oil resources. Since new oil is already deregulated, the removal of controls from old oil would have the effect of providing additional capital to the oil companies to undertake new exploration and production. The argument on the other side is that there are already ample incentives for new exploration and development, that oil companies could not effectively spend the added funds, and that the only effect of deregulation would be to raise the price of petroleum products to consumers. This debate is further complicated by serious proposals to impose excess profits taxes, and break off the marketing segments of the producing companies.

Most offshore and onshore production to which the effluent guidelines would apply are now price controlled. Deregulation would increase these prices to the level of imported crude. This impact analysis cannot even speculate whether deregulation will occur. The limit of the analysis is a statement about the impact of the proposed standards on production if they occur after crude oil prices have been deregulated. Recent tax legislation has effectively ended the depletion allowance for large producers. This change in tax policy has been included in the impact analysis, but other possible changes in tax policies or industry structure are beyond the scope of this analysis, though they could have an important influence on the industry.

Current Crude Oil Pricing Patterns

Domestic crude oil prices have fluctuated very little for 18 of the past 20 years. The years 1973 and 1974 broke this pattern. In 1955, a barrel of crude oil sold for $2.77. By 1971, the price for the same barrel had risen to $3.10. However, in 1973 most domestic crude prices had risen to $5.25 per barrel and would probably have been higher except for a formula worked out by the Federal Energy Agency (FEA) which imposed regulations on crude prices. Table II-15 lists crude prices for various sources for the last five years.

TABLE II-15

HISTORICAL POSTED CRUDE OIL PRICES

CRUDE	1970	1971	1972	1973	1974*
Arab light	1.80	2.285	2.479	5.036	11.651
Iran light	1.79	2.274	2.467	5.254	11.875
Kuwait	1.59	2.187	2.373	4.82	11.545
Abu Dhabi Murban	1.88	2.341	2.540	5.944	12.636
Iraq Basrah	1.72	2.259	2.451	4.978	11.672
Qatar Dukhan	1.93	2.387	2.590	5.737	12.414
Iraq Kirkuk	2.41	3.211	3.402	7.10	-----
Libya	2.53	3.447	3.673	9.061	15.768
Nigeria	2.42	3.212	3.446	8.339	14.691
Sumatra light**	1.70	2.21	2.260	6.00	10.80
Venezuela Tia Juana (31^{o})**	2.193	2.722	2.722	7.762	14.356
Venezuela Oficina**	2.339	2.782	2.782	8.004	14.876
Louisiana	3.69	3.69	3.69	5.29	5.29
East Texas	3 60	3.60	3.60	5.20	5.20
West Texas sour	3.23	3.29	3.29	5.29	5.29

*Year's highest price given, 1974 price effective Jan. 1.

**Official selling price for Sumatra, reference price for Venezuela, all others are posted prices. Kirkuk priced at Mediterranean; U.S. prices are representative postings for crude oil.

SOURCE: Oil and Gas Journal

FEA price regulations are directed at each of the four levels of the domestic petroleum marketing chain. As a result of current FEA regulations, there exists a two-tiered wellhead pricing system for domestic crude. "Old" oil is price controlled at $5.25 per barrel; however, the price of new, released and stripper well crude is free to rise and fall with market fluctuations.

Domestically produced oil which is not price controlled is the amount of oil produced per well per producing property in excess of the crude produced in the corresponding month of 1972 (the excess is termed "new" oil), an amount of oil equal to "new" oil (this equivalent amount is termed "released" oil), and all oil produced from any lease whose average daily production for the preceding calendar year didn't exceed 10 barrels per well.

For an example of new and released oil, assume that in March of 1972 a property with 12 wells was producing 240 barrels of oil per day, or a daily average of 20 barrels per well. If in March of 1974 the same property produced a daily average of 264 barrels from the same 12 wells, or 22 barrels per well, each well would be producing 2 barrels of new crude, 2 barrels of released crude and 18 barrels of old crude. If, because of some occurrence such as water flooding on nearby properties, the daily production per well on the example property rose to 45 barrels per day in March of 1974, each well would be producing 25 barrels of new crude and 20 barrels of released crude per day and no old crude.

By the end of 1974 the composition of total domestic crude was approximately 60% old and 40% new, released and stripper well crude. Actual prices for domestic crude oil under the FEA categories are now $5.25 per barrel for "old" oil and are over $11.00 per barrel for "new" oil. The weighted average of old and new prices is about $7.50. If price controls remain in effect, the average will rise as unregulated oil becomes a larger proportion of total production.

Current U.S. concern with foreign, particularly Middle Eastern, oil prices is that the prices are very high. Until 1973, the reverse was true. As the cost of exploration, development, and production rose in the U.S., American oil companies developed fields abroad where the production costs were much lower than in the U.S.

By the latter half of the 1960's, the Middle Eastern countries had become more sophisticated in dealings with the large companies. An organization called the Organization of Petroleum Exporting Countries (OPEC) was formed to specifically negotiate better deals for the member countries. A double price system was effectively set up when the members of OPEC announced they were going to guarantee their income by posting a price per barrel that would be used to figure their royalty no matter what the real price of crude oil was. That announcement was the beginning of political pricing. The posted price became effective in the latter half of the 1960's with each country posting separate prices. The other price of the double price system, the real price, has historically been below posted price. Table II-16 lists representative posted and actual prices.

TABLE II-16

REPRESENTATIVE POSTED PRICES AND ACTUAL COSTS

PER BARREL OF FOREIGN EQUITY CRUDES AND U.S. CRUDE

	Posted Price	Actual Cost*
Algeria	$16.21	$11.25
Canada	6.68	11.08
Iran	11.87	9.35
Iraq	11.67	9.23
Kuwait	11.54	9.12
Libya	15.76	10.95
Nigeria	14.69	10.26
Qatar	12.01	9.70
Saudi Arabia	11.65	9.20
U.A. Emirates	12.63	9.82
Venezuela	14.87	10.95
U.S. Old Oil	- - -	5.25
U.S. New Oil	- - -	10.20
U.S. Composite**	- - -	7.15
Imported Composite	- - -	10.42
Total Composite	- - -	8.01

*Includes transportation **Domestic only

SOURCE: Platts Price News, June 26, 1974

The movement upwards of the posted price of crude oil forced the real price of crude oil up in order to pay the royalty and still produce a profit. In the world market, oil is traded almost as a commodity, and the price moves up and down according to demand. The effect of the rise in price of foreign crude oil on the price of domestic crude oil has been considerable. Early in the 1950's, the United States Government set up an allowable policy on crude oil imports. The purpose was partly to protect the domestic industry from competition from cheap foreign imports (particularly independents and non-foreign oil-producing companies, as this segment of the industry was in an over-production situation), partly to prevent long-range dependence on foreign oil, and partly to use as a lever against the oil industry to prevent price increases. The whole allowable system was predicated upon foreign oil being cheaper than domestic oil.

The situation has now reversed itself. Foreign oil is now more expensive than domestic oil. However, even though the production costs of most domestic oil is far below the price of imported oil, production cannot meet demand.

The cost of crude includes a wellhead price plus tarrifs, plus cost of delivery to a refinery. Tables II-17 and II-18 list crude price and transportation costs to U.S. refining areas from several producing areas. Table II-17 lists the costs for the average mix of new and old U.S. oil and typical foreign oil. The U.S. oil has a strong competitive advantage in both the crude price and the transportation costs. This advantage has actually grown in recent months as foreign prices have increased faster than the average U.S. price because of price controls. Table II-18 compares U.S. new oil with

TABLE II-17

DELIVERED PRICES OF FOREIGN AND AVERAGE[a] MIX DOMESTIC CRUDE

	West Texas Sour 32°	*Arabian Light 34°*	*Tia Juana Light 31°*	*S. Louisiana Light 37°*	*Canadian Sweet 39°*	*Nigerian Light 34°*
F.o.b. Price	*$7.38	$10.46	$11.10	*$7.63	†$12.15	$11.75
License Fee	...	0.18	0.18	...	0.18	0.18
Sub-total	$7.38	$10.64	$11.28	$7.63	$12.33	$11.93
PHILADELPHIA						
Transportation	0.95	1.40	0.34	0.85	...	0.72
Delivered Price	$8.33	$12.04	$11.62	$8.48	..	$12.65
U.S GULF COAST						
Transportation	0.25	1.39	0.32	0.25	..	0.83
Delivered Price	$7.63	$12.03	$11.60	$7.88	.	$12.76
CHICAGO						
Transportation	0.41	1.58	0.51	0.32	0.50	1.02
Delivered Price	$7.79	$12.22	$11.79	$7.95	$12.83	$12.95
U.S. WEST COAST (LOS ANGELES)						
	‡ *Sour Ventura 28°*					
Transportation	0.20	1.16	0.73	...	...	...
Delivered Price	‡$7.33	$11.80	$12.01	...	...	...

*Average of price-controlled and free market prices. †Allows for currency exchange differentials and includes $5.20 Canadian export tax. ‡Average f.o.b. price $7.13.

a. Average mix of 60-40 price controlled and de-controlled domestic crudes.

Note: Transportation is computed on AFRA basis, with Arabian light trans-shipped via Curacao.

SOURCE: Petroleum Intelligence Weekly, December 9, 1974

TABLE II-18

DELIVERED PRICE OF FOREIGN AND DECONTROLLED DOMESTIC CRUDES

	West Texas Sour 32°	*Arabian Light 34°*	*Tia Juana Light 31°*	*S. Louisiana Light 37°*	*Canadian Sweet 39°*	*Nigerian Light 34°*
F.o.b. Price	*$10.89	$10.46	$11.10	*$11.14	†$12.15	$11.75
License Fee	.	0.18	0.18	...	0.18	0.18
Sub-total	$10.89	$10.64	$11.28	$11.14	$12.33	$11.93
PHILADELPHIA						
Transportation	0.95	0.97	0.31	0.85	..	0.64
Delivered Price	$11.84	$11.61	$11.59	$11.99	...	$12.57
U.S. GULF COAST						
Transportation	0.25	0.96	0.29	0.25	..	0.73
Delivered Price	$11.14	$11.60	$11.57	$11.39	..	$12.66
CHICAGO						
Transportation	0.41	1.15	0.48	0.32	0.50	0.92
Delivered Price	$11.30	$11.79	$11.76	$11.46	$12.83	$12.85
U.S. WEST COAST (LOS ANGELES)						
	‡ *Sour Ventura 28°*					
Transportation	0.20	0.54	0.68	...	...	...
Delivered Price	*$10.83	$11.18	$11.96	...	...	..

*For price control-exempt, free market crude. †Allows for currency exchange differentials and includes $5.20 Canadian export tax. ‡Free market f.o.b. price $10.63.

Note: Transportation costs are on a spot basis.

SOURCE: Petroleum Intelligence Weekly, December 9, 1974 minimum foreign oil prices. One sees in the table that the price of the new oil has risen to just about the same price as the foreign oil when transportation costs are taken into consideration.

While this impact analysis will not attempt to specify crude prices over the period of interest, the subject has been considered by reputable analysts. The Project Independence study considered crude prices ranging from $4 to $11 per barrel. Since Arab prices are now established for political reasons as well as economic, their prices could be reduced conceivably to the $4 level again, though it is unlikely. However, if crude prices were allowed to seek a level reflecting world supply and demand, the Blueprint Report estimated that the long-term price would be about $7 per barrel in 1973 dollars (almost $8 per barrel in 1974 dollars). Former Secretary of the Treasury Schultz testified in February 1974:

> It is reasonable to assume that after about 3 to 5 years, and allowing for some inflation, if the price of oil increases by about 50% from mid-1973 levels, to around $7 per barrel, sufficient domestic oil supplies should flow to satisfy about 85-90% of our demands.
>
> Accordingly, we have for planning purposes estimated that the "long-term supply price" is about $7 per barrel. But the $7 per barrel figure is an estimate and the ultimate figure may be somewhat more or somewhat less. [1]

While the $7 per barrel may be approximately the supply/demand equilibrium price, the prices at the two ends of the spectrum are probably more relevant as prices which may actually be seen. As was noted above, about 60% of current production is frozen at $5.25 per barrel. The President has proposed to remove these price controls, subject to Congressional approval as provided by the Emergency Petroleum Allocation

[1] "Windfall" or Excess Profits Tax, Committee on Ways and Means, U.S. House of Representatives, pp. 135, 1974.

Act. On the other hand, there is a strong move in Congress to reimpose price controls more generally on the economy rather than relaxing them.

If old crude prices are decontrolled, the resultant change in per barrel revenues to the oil companies may not be equal to the increase in crude prices. The combination of excise taxes on imports and the excess profits tax as proposed by the President could result in an added net income of only $0.89 per barrel in pre-tax (corporate tax) revenues to the companies, based on an analysis of the total tax and deregulation package which was reported in Platt News of Jan. 20, 1975. This analysis showed that the weighted average U.S. domestic price less severance tax was $6.97 based on price-less-tax levels of $10.23 for new oil and $4.88 for old oil (39% to 61% ratio). If deregulated, U.S. crude prices will rise to $14 per barrel, slightly less than the landed price of foreign crude (including the proposed $3 excise tax). The taxes on the domestic crude would include: $2 excise tax; 7% severance tax on the $12; and $3.30 windfall profits tax. The net revenue to the firm would then be $7.86 per barrel, an increase of $0.89 over present revenues. There is of course no way to know at this point whether all, part, or none of the package will be enacted.

The following analysis of potential oil production losses as a result of the proposed effluent guidelines has used $5.25 and $11.00 crude prices to test the range of potential impacts. They are intended to be representative of the price range producers could have experienced at the end of 1974.

3.2. Pricing of Offshore Natural Gas at the Wellhead

Introduction

The price of natural gas is set at the time of production according to its entry into either the intra- or interstate markets. Intrastate prices are not regulated and respond freely to the fluctuation of supply and demand. Interstate prices are controlled by the Federal Power Commission which has jurisdiction over gas produced in federal offshore areas, gas produced and sold across state lines and gas moving through any segment of an interstate pipeline system.

Prior to 1973, the new, long-term contract prices received by natural gas producers for intra- and interstate sales were not significantly different. However, in late 1973, prices for intrastate gas began to rise to levels occasionally tripling the fixed prices of interstate gas, and in 1974 intrastate prices were in the range of $1.95 per thousand cubic feet (MCF), roughly four times greater than the interstate price of $0.51 per MCF (see Table II-19). A consequence of the price disparity has been the extreme shift to intrastate markets of the commitments of natural gas reserve additions as early as 1969.

If it is assumed that all of the new reserves reported by AGA not committed to the interstate pipelines are being committed to the intrastate gas market, it appears that the intrastate market may well have captured 99% of the 1970 net U.S. reserve additions, 80% of the 1971 net reserve additions, 100% of the 1972 net additions, and 82% of the 1973 net reserve additions (see Table II-20).

TABLE II-19

Prices Received by Producers for
Natural Gas Sales, 1966-1975
(cents per thousand cubic feet)

	Average Wellhead Prices	New Long-Term Interstate Contracts	New Gulf Coast Intrastate Contracts
1966	15.7	17.7	15.[illegible]-19.5
1967	16.0	18.8	15.[illegible]-19.6
1968	16.4	19.6	16.1-20.2
1969	16.7	19.9	14.4-21.5
1970	17.1	22.3	18.5-23.0
1971	18.2	24.8	20.6-26.2
1972	18.6	35.1	23.5-30.0
1973	21.6	40.3	25-125
1974	26.7	43-51	125-195
1975	35.0		175-210

Sources: Foster Associates; U.S. Bureau of Mines, *Natural Gas Annual, 1973*, Federal Power Commission; Jensen Associates; and Arthur D. Little, Inc., estimates.

TABLE II-20

LOWER 48 STATE
NET RESERVE ADDITIONS
INTERSTATE VS. INTRASTATE

Year	Total Net AGA Reserve Additions Tcf	Net Interstate Reserve Additions (Form 15) Tcf	Percent	Inferred Intrastate Reserve Additions[1] Tcf	Percent
1964	20.1	10.7	53	9.4	47
1965	21.2	13.3	63	7.9	37
1966	19.2	14.1	73	5.1	27
1967	21.1	14.8	70	6.3	30
1968	12.0	9.5	79	2.5	21
1969	8.3	6.0	72	2.3	28
1970	11.1	0.1	1	11.0	99
1971	9.4	1.9	20	7.5	80
1972	9.4	(0.2)	0	9.6	100
1973	6.5	1.2	18	5.3	82

[1] Derived by assuming that intrastate reserve additions are equal to the difference between total AGA reserve additions and the reserve additions committed to the interstate market.

SOURCE: "The Oil and Gas Compact Bulletin", December 1974

Prior to 1970, there were sufficient domestic supplies of gas; however, beginning in 1970, onshore gas procurement became difficult for the interstate market. In 1970, the interstate pipelines procured 75% of their long-term new gas from onshore sources; in 1971, the percentage dropped to 54%; in 1972, it dropped to 41%; and in 1973, it dropped to 33% (Table II-21).

The increased dependence of interstate pipelines on offshore purchases, or the inability of the interstate pipelines to buy gas onshore, appears to be attributable to the FPC rate structure which makes it difficult for the interstate pipelines to compete for new supplies.

Because offshore areas are the most expensive to develop, offshore gas exploratory footage has declined since 1970 (see Table II-22). Since 1970 the percentage of footage of offshore development drilling relative to total U.S. gas development footage has also declined (see Table II-23).

While all natural gas produced in Federal waters is by definition interstate gas, the gas produced in state waters can be either inter- or intrastate depending on its transmission pipeline and the location of its purchaser. Gas from Federal waters is 85% of the total natural gas produced in the Gulf of Mexico. Fourteen percent of the Gulf production is from Louisiana state waters and the majority of this production also is from older wells under interstate contracts. The Texas state waters production is primarily dedicated to plants in Texas and is intrastate gas, but it is only 0.3% of total offshore natural gas production.

Because natural gas from the Gulf of Mexico is primarily interstate gas, the economic impact analysis has focused on interstate gas prices as controlled by the FPC.

TABLE II-21

ESTIMATED NEW LONG-TERM CONTRACT
SALES BY LARGE PRODUCERS 1970-1973
OFFSHORE FEDERAL DOMAIN vs. ALL AREAS
(Million Mcf)*

Year	All Area[1] Sales	Sales Offshore[2]	Offshore Percent [2]	Sales Onshree	Onshore Percent
1970	302.6	73.3	24.2	229.3	75.8
1971	453.7	207.7	45.8	246.0	54.2
1972	474.3	279.4	58.9	194.9	41.1
1973	330.3	221.1	66.9	109.2	33.1

* Figures derived from applications filed with the Commission for new long-term sales certificates.
1 FPC pricing areas and California (Federal domain)
2 Federal domain areas offshore Louisiana, Texas and California.

SOURCE: "The Oil and Gas Compact Bulletin", December 1974

TABLE II-22*

	Total U. S. Gas Exploratory Footage (million feet)	Offshore Gas Exploratory Footage (million feet)	Offshore as Percentage of total
1970	3.7	.26	7.0
1971	3.3	.41	12.4
1972	4.6	.14	3.0
1973	6.2	.17	2.7
1974 (1st half)	3.8	.08	2.1

* All figures taken from the latest publication of "Gas Supply Indicators" by the FPC Office of Economics, issued October 25, 1974.

Gas development footage shows the same pattern. In 1971, offshore development footage was 8.8 percent of the national total. This dropped to 7.8 percent in 1973, and declined to 6.1 percent for the first six months of 1974.

TABLE II-23*

	Total U. S. Gas Development Footage (million feet)	Offshore Gas Development Footage (million feet)	Offshore as Percentage of total
1970	19.2	1.6	8.3
1971	19.3	1.7	8.8
1972	22.2	1.5	6.8
1973	29.4	2.3	7.8
1974 (1st half)	16.0	0.97	6.1

* All figures taken from the publication of "Gas Supply Indicators" by the FPC Office of Economics, issued October 25, 1974.

SOURCE: "The Oil and Gas Compact Bulletin," December 1974.

Regulation of Natural Gas Producers[1]

In 1954 the U.S. Supreme Court held in Phillips Petroleum Co. versus Wisconsin that the Federal Power Commission was responsible not only for the regulation of the interstate pipeline companies but also for the regulation of sales to those pipeline companies by natural gas producers in the field. There had been up to this point a major controversy concerning the language and intent of the Natural Gas Act of 1938 with respect to sales by producers. When this Supreme Court decision was followed by an unsuccessful attempt to exempt producers from regulation through Congressional legislation, the Federal Power Commission began to grapple with the problem of how to actually carry out its charge.

The first efforts involved attempts to determine for each producer his costs of production, capital, etc. in order to apply the rather traditional formula of rate of return regulation. In this framework, the producer would be allowed to charge a price for his gas which would cover his costs of production (including depreciation) and grant a return on his capital which would be sufficient for him to cover his "cost of capital."

---

[1]This summary is based on the history of FPC natural gas producer regulations as detailed in Breyer and MacAvoy, Energy Regulation by the Federal Power Commission, The Brookings Institution, Washington, D.C., 1974.

There were several very difficult problems in implementing this regulatory scheme. For one, gas and oil are found together about 25% of the time, but oil is not regulated. Thus, there are joint costs of exploration and production which can by no existent economic theory be unambiguously assigned to gas as opposed to oil. The same problem exists with allocating capital to gas and oil. Besides this, to determine an appropriate cost of capital, one might look at the rates of return in comparable companies in comparable industries. Unfortunately for the FPC, such comparable companies were not to be found. The final problem, however, was simply the enormity of the process. From 1954 to 1960 the FPC completed only ten out of nearly 3,000 cases before them. In 1960, therefore, a new approach was decided upon -- the area rate concept. The FPC divided the Southwest into five regions and determined to set prices on a 2 tier system -- one price for gas on old contracts and a higher price for gas on new contracts. The intent was to minimize windfall profits on already committed gas while not unduly restricting future investment in gas exploration and development. Because the decisions in the area rate proceedings were still years away, the FPC decided to control prices during the interim through a two-sided policy: (1) the producers would be compelled to refund to the pipeline companies (and ultimately the consumers) any revenues made in excess of those which would have been made at the price yet to be determined by the Commission; and (2) new contracts had to be approved by the FPC. The effectiveness of these deterrents to price increases is exemplified by the essentially constant price of gas through the 1960's while the area rate proceedings were going on.

The first area rate proceeding to be completed was the one for the Permian Basin of West Texas and Southeast New Mexico. Prices were set at 16.5¢/MCF, only slightly higher than the 1960 rate. The initial decision of the Commission in Southeast Louisiana was also issued in late 1968, but revisions, court cases, and so forth dragged the "final" decision out to 1971.[1] This decision was noteworthy in that the procedures of the FPC were again dropped and in their place the FPC substituted its acceptance of a "settlement" between the producers, distributors, and other customers at about 26¢/MCF (new gas).

MacAvoy and Breyer[2], as well as many other economists/critics of the FPC, have detailed the flaws in the FPC price setting schemes. For one thing, there was an inherent bias in the cost estimates determined during the proceedings because of the interim price ceilings. Producers would not attempt to produce gas which would cost more than they could charge for it. The more risky ventures were not attempted. Thus, the interim prices (at 1960 level) determined producers' costs which determined final ceiling prices at little more than the 1960 level. The additional unexpected result was that the relative price of gas to final consumers stayed so low during the '60's that a great deal of demand was generated which would have gone to oil or coal had gas prices been allowed to rise. At the same time, the low price discouraged investment in exploration and development so that well drilling and subsequent discoveries fell well below production until, in the early 1970's, production could not keep up with demand.

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[1] 46 FPC 86 Opinion 598.

[2] MacAvoy, P. and S. Breyer, ibid.

The clamor over curtailments and other elements of the energy crisis brought pressure on the FPC to review again its ceiling price decisions.

The FPC this time went one step further in simplifying its procedures: it adopted in June 1974 a uniform national rate for wellhead prices on new gas (produced after January 1, 1973).[1] The new prices set were 42¢/MCF (plus taxes, royalties, etc. as applicable). In addition, in a notice of proposed rulemaking[2], the FPC proposed that "small producers" would be allowed to charge a price 50% higher than the larger producers, in order to allow them to stay competitive with the larger producers.

Then in December 1974, the uniform national rate was increased to 50¢/MCF retroactive to June 21, 1974, subject to 1¢/MCF annual increases[3]. This increase was primarily the result of the FPC's decision to use the discounted cash flow (DCF) methodology for calculating producers' return on investment, a method they had previously declined to use.

Before discussing the cost determinations which resulted in the 42¢/MCF and then the 50¢/MCF price ceiling, one comment is in order. If it appears that there is a certain amount of arbitrariness and instability in these decisions, it is because there is. The FPC has been charged by the courts to set "just and reasonable rates", but it has also been allowed to use whatever

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[1] FPC Opinion 699, 21 June 1974.

[2] FPC Notice of Proposed Rulemaking, 9 September 1974.

[3] FPC Opinion 699H, 4 December 1974.

methods it deems reasonable to do so. No unambiguous "formula" has been determined for this purpose. The methods chosen, then, attempt to determine actual costs within a "zone of reasonableness"[1] and to base ceiling prices on this estimated range. But because both the costs to the producers and the methodology for combining these costs have repeatedly changed, the rate structure has undergone several major changes in the last ten years.

Nationwide Costs of Finding and Producing Non-Associated Gas

In Table II-24 are displayed eight different estimates used by the FPC in June 1974 for the costs of various factors involved in the production of natural gas. The only difference between the pairs (c) and (d) and (e) and (f) is the assumed investment life (9 and 10.5 years respectively). Columns (g) and (h) are based on different estimates of the expected productivity (in MCF/ft drilled) of future drilling. As will be seen below, this is by far the most important variable in these cost determinations.

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[1]FPC Opinion 699.

Docket No. R-389-B

TABLE II-24

Estimated Nationwide Cost of Finding and Producing Non-Associated Gas
(14.73 psia)
(Cents Per Mcf)

Line No.	Cost Component	Update Low (c)	Update High (d)	Revised Update Low (e)	Revised Update High (f)	10 Year Estimate (g)	4 Year Estimate (h)
	Productivity Assumption (mcf/ft)	559	485	559	485	552	336
1.	Successful Wells	4.93	5.68	4.93	5.68	4.99	8.20
2.	Recomp. & Deeper Drilling	.20	.20	.20	.20	.20	.20
3.	Lease Acquisitions	3.32	3.83	3.32	3.83	3.36	5.13
4.	Other Production Facilities	1.11	1.28	1.11	1.28	1.13	1.85
5.	Subtotal	9.56	10.99	9.56	10.99	9.68	15.38
6.	Dry Holes	3.27	3.77	3.27	3.77	3.32	5.45
7.	Other Exploration	2.27	2.62	2.27	2.62	2.30	3.68
8.	Exploration Overhead	.71	.82	.71	.82	.72	1.16
9.	Subtotal	6.25	7.21	6.25	7.21	6.34	10.29
10.	Operating Expense	3.10	3.10	3.10	3.10	3.10	3.10
11.	Return @ 15% & 9 years	12.77	14.70				
11a.	Return @ 15% & 10½ years			14.90	17.15	15.09	24.07
12.	Return on Working Capital	1.00	1.14	1.00	1.14	1.01	1.51
13.	Net Liquid Credit	(3.89)	(3.89)	(3.89)	(3.89)	(3.89)	(3.89)
14.	Regulatory Expense	.20	.20	.20	.20	.20	.20
15.	Subtotal	28.99	33.45	31.12	35.90	31.53	50.66
16.	Royalty @ 16%	5.52	6.37	5.93	6.84	6.01	9.65
17.	Total @ 14.73 psia	34.51	39.82	37.05	42.74	37.54	60.31

SOURCE: FPC Opinion 699

Successful Wells Cost

The successful wells cost was determined by taking the average cost of drilling (in this case, the 1972 Joint Association Survey[1]) and dividing it by the expected productivity of successful wells in MCF/ft drilled. A great deal of controversy was involved in determining the productivity, as it is the single most important factor in determining total costs. Figure II-2 presents a history of the productivity from 1947 to 1972. As can be seen, there is a tremendous variance in this curve, though since the mid-60's the trend has been steadily downward. In the face of a great deal of conflicting evidence presented by industry analysts, public utility associations, etc., the FPC decided that a "zone of reasonableness" was between 485 and 559 MCF/ft drilled for the productivity. From this and the JAS figures, a successful wells cost between 4.93 and 5.68¢/MCF was decided upon. (See columns (e) and (f) of Table II-24.) Few differing opinions were expressed to the FPC concerning other costs involved in setting up production in successful wells (items 2, 3, and 4). Line 5 is a total of these costs (1-4).

Dry Holes

An allowance was made for exploration and drilling costs associated with unsuccessful wells or "dry holes". Factors which account for differences in the costs of successful and unsuccessful wells, their relative numbers, etc. were included in the determination of lines 6, 7, 8, and their total (line 9) in Table II-24.

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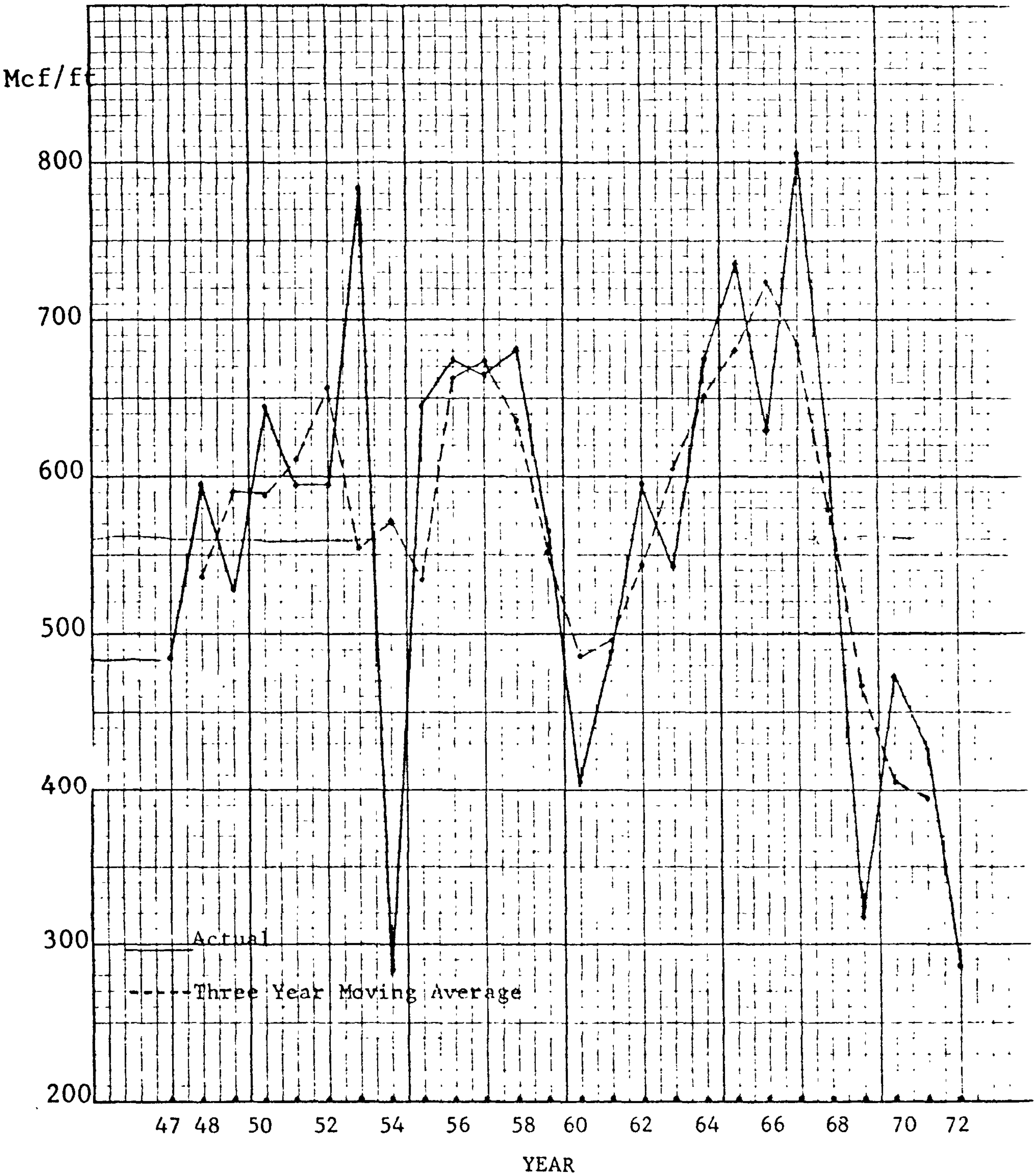
[1] Joint Association Survey of the U.S. Oil and Gas Producing Industry; API, IPAA, MCOGA; 1972.

FIGURE II-2

NON-ASSOCIATED GAS RESERVES ADDITIONS PER FOOT DRILLED
IN WELLS PRODUCTIVE OF GAS AND CONDENSATE
UNITED STATES EXCLUDING ALASKA, 1947 - 1972



SOURCE: Federal Power Commission, Opinion 699

Operating Expense

Operating expense, an item not argued about by the respondents, was determined to be 3.1¢/MCF.

Return on Investment

Historically, several points of controversy have surrounded this item. First, what is the base on which it is determined? Producers have argued that their investment in exploration which results in dry holes should be counted equally with their successful well costs in the determination of their rate base. The FPC in June 1974 disagreed, citing the "value to the public of the services they perform is measured by the quantity and character of the natural gas they produce, and not by the resources they have expended in its search ..."[1] In December 1974, however, the FPC decided to include a dry hole cost in their new discounted cash flow (DCF) approach.

The rate of return was set by the FPC as 15%, the upper end of the "zone of reasonableness" of 12% to 15% they determined to be applicable for natural gas producers. The investment life was set to be 9 years based on an 18 year depletion time. In addition, a lag period of 1.5 years was added to account for the time between lease acquisition and the commencement of actual production.

The total return in the June 1974 decision was then calculated by multiplying the production costs (line 5, Table II-24) by the rate of return (15%)

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[1] FPC versus Hope Natural Gas Co., 320 US 591, 649.

and the investment life (10.5 years) to get a range of 14.9 and 17.15¢/MCF (line 11a).

In addition to the factors discussed above, the unargued items in lines 12, 13, 14, and 16 were added to come up with a total (line 17) which ranged between 37.05¢ and 42.74¢/MCF. The FPC, in order to encourage exploration and development investment, decided to set the price ceiling at the upper edge of this range with a small (1¢/year) escalation to account for future cost increases.

The one remaining point of contention concerned whether Federal income taxes were an acceptable cost item. The FPC took the stance that a blanket nationwide figure would not be adequate for this item because "the complex nature of the Federal tax laws negate any simple calculation of a Federal tax liability and require consideration of the producer's tax returns in order to consider the timing relationships between investment expenditure, the expensing of intangible drilling costs, and jurisdictional sales."[1] The FPC decided, therefore, not to include this item at all in its cost computations.

In December 1974 the FPC revised its earlier methodology by using a discounted cash flow approach. This approach led to a range of between 48¢ and 52¢/MCF for the "economic cost" of natural gas, including a 15% DCF rate of return to the producer. Thus, the value of 50¢/MCF was decided upon with 1¢/MCF increments to be added yearly.

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[1] FPC Opinion 699

Some Conclusions

The FPC is under considerable continuing pressure from economists, industry spokesmen, and Congressional critics to revamp its price setting policies to effect further deregulation of natural gas producers in order to cope with the growing demand and slackening production of natural gas. It well recognizes the decline in the late 60's and early 70's of exploration and development activities brought about by an abnormally low relative price for gas and is attempting to rectify the situation while yet carrying out its Congressional and judicially affirmed mandate to keep price at a "just and reasonable rate." The trend in FPC regulation has definitely been in the direction, however, of a phased deregulation over a number of years.

In the cost determinations the FPC has made in the past, there has been a concerted effort to account fairly for the costs that are actually incurred in producing natural gas. On the basis of previous FPC opinions in this regard, it appears that additional costs due to equipment required by law would be included by the FPC in line 4 (other production facilities), and would, therefore, be passed on to the pipeline company (and to the ultimate consumer) in the form of higher prices. This opinion is supported by a conversation with Lundy Wright, Chief of Producer and Pipeline Rights Division of the FPC [1], who made it clear, however, that it was the Commissioners and not himself who made such decisions. Assistant General Counsel Robert W. Purdue of the FPC agreed also [2], pointing out that under FPC Order No. 481 (18 CFR 2.76),

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[1] Personal conversation, 8 November 1974.

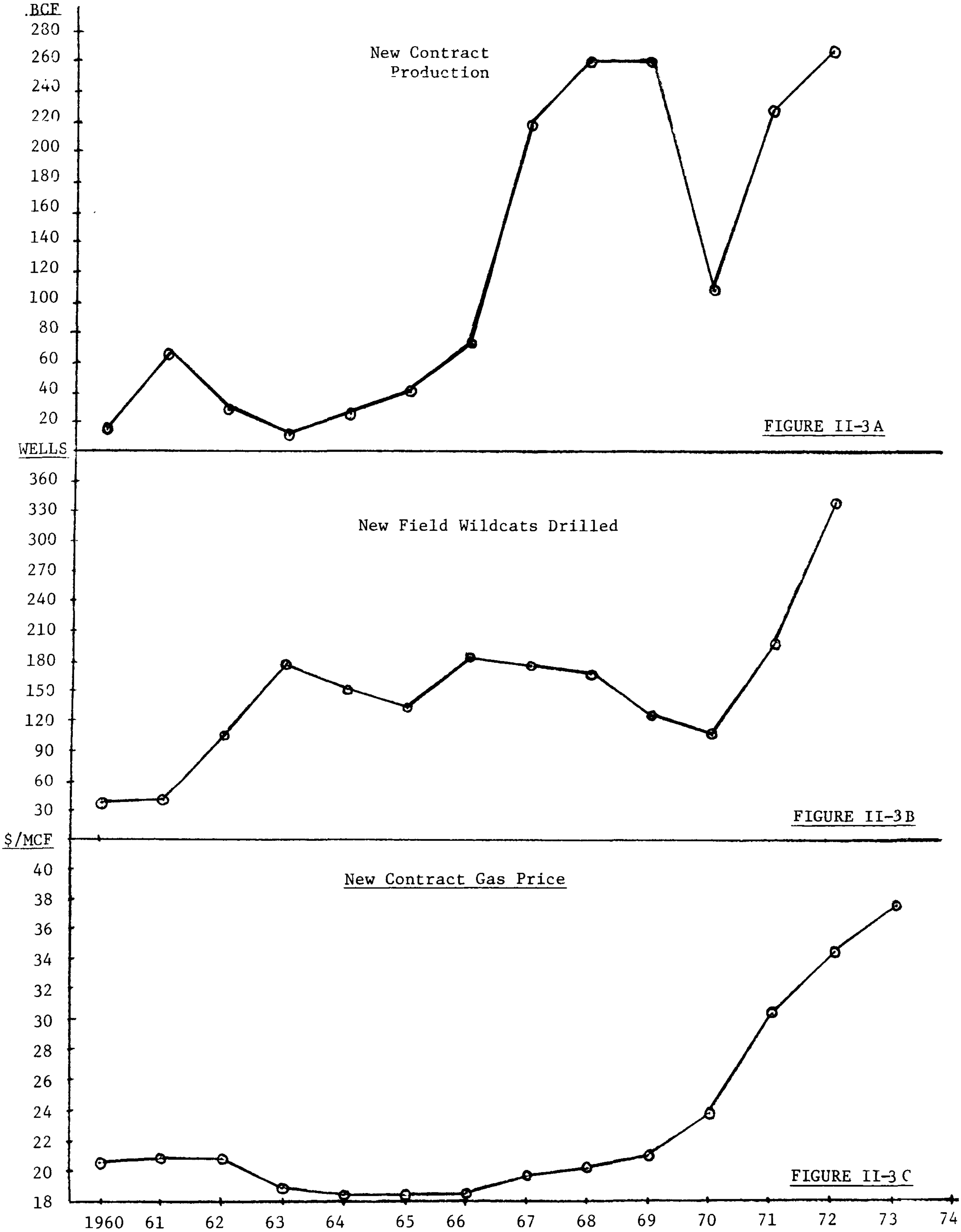
[2] Personal conversation, 15 November 1974.

producers may file for relief from special costs such as this. He gave as a current example the case of the Sun Oil Company in the Hugoton field in Oklahoma which has been granted price increases to account for the added costs of reinjection wells drilled in compliance with Oklahoma standards on salt water disposal. He suggested that in many cases the state regulations may be more stringent than what the EPA will propose. Thus, he expressed confidence that the FPC would grant special allowances on legitimate additional required equipment costs.

The one question which remains is whether the FPC would continue to grant relief to individual producers according to Order No. 481 or whether they would adjust the nationwide ceiling prices to account for these added costs. In addition to these special allowances, the FPC has recognized that the costs of small producers are often both higher and more difficult to bear than those of the larger producers. As stated earlier, the FPC's intention is to allow small producers to charge a 50% higher rate for new contract gas. It is true, therefore, that the small producers are more protected against increasing costs due to new required equipment than if they were limited by the 50¢ ceiling. Whether this will be sufficient without special relief via Order 481 will depend on the individual case, though from a superficial view, it appears that they would certainly be protected by both these factors.

Figures II-3A, B, & C show the histories of new contract production, new field wildcat drillings, and new contract price for offshore Louisiana gas. One can clearly see that the price of gas remained essentially at or below the 1960 level throughout the entire decade of the 60's. During that time, new field wildcats (and the resulting discoveries) peaked out and then fell to two-thirds of their highest (1966) point. New contract production rose steadily until it peaked in 1968 and fell sharply in 1970 as reserves continued to decline and producers were forced to curtail previously contracted sales to interstate pipeline companies. As new contract price rose sharply during the first years of the 70's, new contract production and new field wildcats rose dramatically as well.[1] These graphs indicate that the price level is an important factor in investment in exploration and production of natural gas in the 1970's.

[1]Unfortunately, these production increases on new contracts have not been sufficient to keep curtailments of production on older contracts from occurring. According to FPC News Release No. 20849, these curtailments amounted to over 218 billion cubic feet from September 73 to September 74 and are expected to rise to 266 billion cubic feet between September 74 and September 75.



SOURCE: Foster Associates, Washington, D.C.; and MIT Energy Lab, Cambridge, Mass.

II.4. FINANCIAL CHARACTERISTICS

4.1. The Role of Financial Characteristics in the Economic Impact Analysis

The oil and gas production industry has many unusual financial characteristics reflective of the risks of the business, its special tax status, and its special cash flow patterns. In examining the financial characteristics as part of this economic impact analysis, three issues are important:

- Are firms in the industry constrained in their access to the required capital for pollution control so they may be forced to close by the proposed effluent guidelines?
- What are the profitability levels and patterns in the industry and will they be changed by the pollution control requirements?
- What is the cost of capital for the industry?

These issues are addressed in the following section. In the earlier characterization of firms in the industry, the predominance of the major oil companies in offshore operations was noted. The examination of the financial characteristics of offshore operations thus primarily concerns the impact of the capital costs of pollution control on capital budgets of the major oil companies and the proper definition of the cost of capital for these investments.

4.2. Income Statements and Profitability

The profitability of the oil and gas industry is a subject of heated debate between the industry and its critics and within the Congress. High profitability is argued by the industry to be necessary to compensate for low profitability in earlier years and to generate funds for finding and developing new reserves and building new processing facilities. Price controls, proposed "windfall profits" taxes, and the recent end of depletion allowances are expressions of widespread belief that the industry's profits are or will be excessive.

The Chase Manhattan Bank publishes a compilation of the financial reports of 30 major oil and gas companies, including four foreign companies called the Chase Group. These firms account for 71% of total U.S. crude oil production and 83% of Gulf OCS production. Table II-25 displays the total income statements for the Chase Group from their worldwide operations for 1971, 1972, and 1973. The Group's net income on revenues was 8.7% in 1973, 6.5% in 1972, and 7.4% in 1971. The portion of net earnings attributed to operations in the U.S. were 35.4% in 1973, 53.4% in 1972, and 48% in 1971.

The interpretation of oil industry profitability has been particularly controversial because of several important tax privileges. Provisions such as the percentage depletion allowance, foreign tax credits, and the expensing of intangible drilling costs are argued to have led in the past to an understating of true industry profitability. The magnitude of these allowances are discussed later. But in understanding the industry and the impact of added costs of operations such as pollution control costs, one must appreciate the industry's very unusual situation, particularly regarding U.S. operations. At present, the per barrel revenues which a company receives for oil is largely

TABLE II-25

INCOME STATEMENT OF CHASE GROUP FOR 1971, 1972, AND 1973

	1973 ($ million)	1972 ($ million)	1971 ($ million)
Gross Operating Revenue	130,948	104,159	95,104
Non-Operating Revenue	2,961	2,119	2,756
Total Revenue	133,909	106,278	97,860
Operating Costs & Expenses	90,298	74,413	68,805
Taxes - Other than Income Taxes	6,241	5,138	4,413
Write-Offs (incl. depreciation & depletion)	8,345	7,514	7,079
Interest Expenses	2,008	1,774	1,597
Other Charges	37	22	23
Total Deductions	106,929	88,861	81,917
Net Income before Income Taxes	26,980	17,417	15,943
Estimated Income Taxes	14,889	10,301	8,409
Income Applicable to Minority Interests	413	256	265
Net Income (a)	11,678 (b)	6,860	7,269

(a) Includes earnings from operations outside U.S.: 1973-$7,544 million; 1972-$3,204 million; 1971-$3,779 million.

(b) Excludes $84 million of extraordinary gains primarily from the sale of assets.

SOURCE: "Financial Analysis of a Group of Petroleum Companies, 1972 and 1973," The Chase Manhattan Bank unrelated to either the cost of producing the oil or the demand for oil. "Old" U.S. oil is price controlled at $5.25 per barrel and "new", uncontrolled oil is floating above the OPEC established world price because of U.S. tariffs on imported oil. If old oil were decontrolled, as has been proposed, its price would rise to the world level or above as well. While there is a wide variation in the cost of producing oil, in fact most current U.S. production has been operating at cost levels low enough to make $5.25 prices profitable. Further price rises will make production economical in higher cost wells, but it will also mean substantial increases in profits for most wells now producing at $5.25 prices, about 60% of U.S. production. The level of profitability actually experienced by the industry will be determined to a significant degree by Federal tax policies. The issue with which the Congress, FEA, the Treasury Department and the industry have been contending is what profit level is needed to provide a fair return on the industry's investment and thereby provide a necessary incentive for expanding domestic production. After that profitability level is determined, if it can be, profits will probably be fixed by controlling prices and/or the additional profits will be taxed away. The central point is that profitability for the industry, particularly the larger companies, will be determined more by Federal tax and pricing policies than the economics of production. Until the specific policies and regulations are established, there will be a considerable uncertainty (perceived risk) on the part of the companies and investors as to the industry's future.

The currently existing tax laws have encouraged the oil companies to spend funds generated by current operations on exploration and development of new wells. Most of these expenditures can be charged against revenues rather than capitalized. The level of spending is such that U.S. tax liabilities will be very small or zero. In addition, the after tax profit on net worth has been kept generally in line with other industries, so the industry will continue to have access to equity markets. Figure II-4 shows the return on net worth of the petroleum industry and other manufacturing industries over the last 13 years.

Table II-26 lists a compilation of net income after tax and the rate of return on equity for 22 U.S. oil companies for the years 1963 through 1973. Table II-27 lists the rates of return by various measures for the Chase Group for 1971, 1972, and 1973.

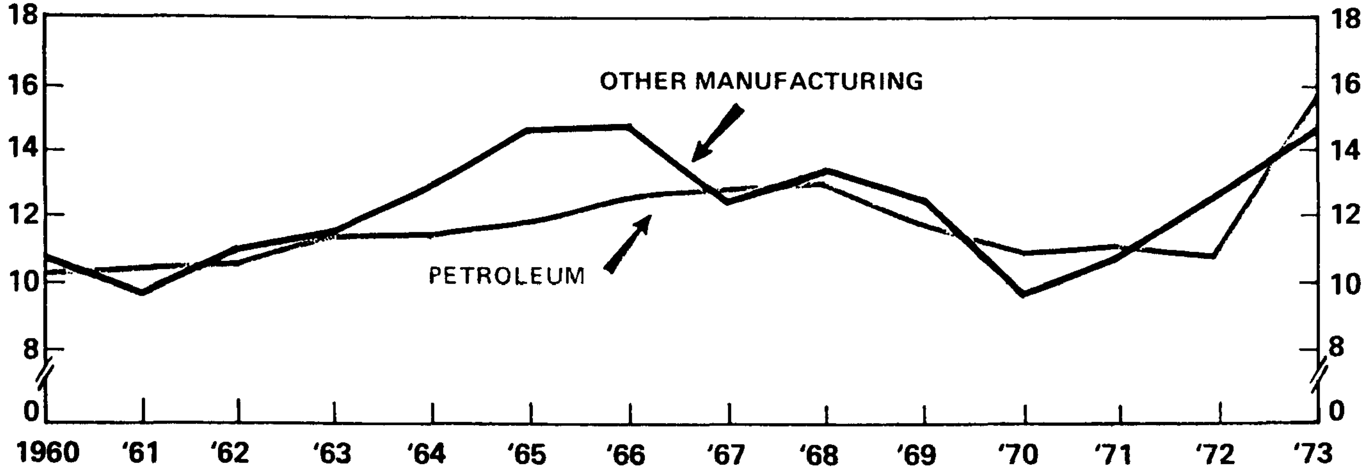
A survey was conducted of the net incomes and cash flow of the significant offshore producers. Table II-28 displays these values for 1973.

The concept of oil industry profitability being set by government tax policy is reflected in the windfall profits tax proposals by former President Nixon and President Ford. In testimony by former Secretary of the Treasury, George Shultz, on February 4, 1974, before the House Ways and Means Committee, the rationale advanced for a windfall profits tax was that the $9.50 per barrel price of U.S. new oil (at that time) was substantially in excess of the price necessary to satisfactorily increase U.S. oil production.

FIGURE II-4

AFTER TAX RETURN ON NET WORTH

PETROLEUM VS. OTHER MANUFACTURING COMPANIES – 1960 TO 1970
(Percentages)



SOURCE: "Energy Memo," January 1975, First National City Bank, NY

Net income after tax and the rate of return on equity of 22 U.S. oil companies (1963-73)

$ millions

Company	1973 Net income	1973 % return*	1972 Net income	1972 %	1971 Net income	1971 %	1970 Net income	1970 %	1969 Net income	1969 %	1968 Net income	1968 %	1967 Net income	1967 %	1966 Net income	1966 %	1965 Net income	1965 %	1964 Net income	1964 %	1963 Net income	1963 %
Amerada Hess†	151.8	23.5	46.2	8.3	133.3	24.0	114.0	25.7	86.5	23.7	89.8	19.8	76.8	22.2	73.1	22.6	63.4	22.2	59.4	23.0	52.4	22.7
Ashland	93.3	17.3	68.0	13.5	40.5	8.8	52.0	11.7	56.9	13.3	53.6	14.6	48.4	15.5	45.0	17.6	35.8	15.5	23.7	14.0	18.1	11.7
•Atlantic Richfield	270.2	8.9	192.5	6.5	210.5	7.3	209.5	7.5	230.1	8.5	105.8	7.8	130.0	10.2	113.5	9.4	90.1	8.1	47.1	7.3	44.9	7.0
•Cities Service	135.6	9.8	99.1	6.9	104.5	7.7	118.6	8.9	127.2	10.0	121.3	9.9	127.8	10.9	120.1	11.0	100.6	10.2	84.5	9.1	77.5	8.6
Clark	30.5	29.9	8.3	9.8	3.6	4.7	10.8	14.0	13.0	18.7	12.1	20.4	11.5	23.4	9.6	24.2	8.7	27.8	2.1	8.9	1.5	6.8
•Continental	242.7	14.0	170.2	10.4	140.1	9.1	160.3	10.7	146.1	9.8	150.0	10.6	136.1	10.1	115.6	10.3	96.2	10.2	100.1	11.1	87.4	10.5
•Exxon Corp.	2,440.0	18.5	1,531.8	12.5	1,516.6	13.1	1,309.5	12.0	1,242.6	12.3	1,276.7	13.0	1,155.0	12.3	1,090.1	12.1	1,021.4	11.9	1,050.6	12.6	1,019.5	12.8
Getty	135.0	8.8	76.1	5.2	120.1	8.5	103.2	7.8	105.8	8.3	98.3	8.3	118.2	10.5	92.3	9.0	57.7	6.9	43.0	5.6	43.0	6.1
•Gulf†	760.0	14.0	447.0	8.3	561.0	10.2	550.0	10.4	610.6	12.1	626.6	13.2	568.3	12.9	501.8	12.3	427.2	11.2	395.1	11.0	371.4	10.9
•Kerr-McGee†	58.8	10.8	50.6	10.1	40.7	10.8	35.9	10.3	33.6	10.3	36.4	12.0	32.1	11.5	33.0	12.9	25.1	14.6	20.7	14.7	18.8	15.8
Marathon	129.4	15.2	79.8	10.2	88.7	11.7	86.5	11.8	89.4	12.1	83.3	12.7	73.9	12.3	68.8	12.3	60.1	11.3	60.4	11.8	49.1	10.2
•Mobil	842.8	15.7	574.2	10.9	540.8	10.9	482.7	10.4	456.5	10.4	430.7	10.3	385.4	9.8	356.1	9.5	320.1	9.1	294.2	8.8	271.9	8.5
Murphy	53.6	24.4	14.3	7.6	11.1	6.2	9.3	6.5	6.2	4.5	7.3	5.4	8.2	6.2	8.1	7.6	6.4	6.1	4.3	4.9	4.8	5.7
Phillips	239.4	12.1	148.4	8.1	132.3	7.6	132.3	7.8	127.8	7.7	129.9	8.0	164.0	11.0	138.4	10.3	127.7	9.9	115.0	9.3	108.1	8.9
•Shell	332.7	10.9	260.5	8.9	244.5	8.7	237.2	8.6	291.2	10.9	312.1	12.3	284.9	13.8	255.2	13.4	234.0	13.4	198.2	12.3	179.9	12.0
Skelly	44.0	7.5	37.6	6.8	38.3	7.0	36.1	7.0	38.4	7.7	40.3	8.5	42.0	9.3	37.0	8.8	34.0	8.8	25.7	7.1	[illegible]	7.0
•Standard of Calif.	843.6	14.4	547.1	10.5	511.1	10.4	454.8	9.8	453.8	10.3	451.8	10.7	409.4	10.3	401.2	10.8	391.2	11.1	345.3	10.5	322.1	10.5
•Standard (Ind.)	511.2	12.4	374.7	10.0	340.6	9.6	314.0	9.3	321.0	10.0	309.5	10.1	280.9	9.6	255.9	9.1	219.3	8.1	194.9	7.5	183.1	7.3
Standard (Ohio)	74.1	6.6	59.7	5.6	58.8	5.7	64.4	6.3	51.9	5.3	70.1	13.0	67.1	14.5	56.9	13.3	49.7	12.7	43.8	12.0	33.3	11.4
•Sun	230.0	12.3	154.7	8.8	151.6	8.9	139.1	8.4	152.3	9.4	164.4	10.9	156.2	15.2	100.6	10.8	85.5	10.1	68.5	8.8	61.2	8.1
•Texaco	1,292.4	25.0	889.0	12.4	903.9	13.4	822.0	13.1	769.8	13.1	819.6	14.5	754.4	14.8	692.1	15.0	636.7	14.9	577.4	14.6	547.6	15.6
•Union of Calif.	180.2	10.6	121.9	7.6	114.7	7.4	114.5	7.6	138.9	9.5	149.8	10.9	145.0	11.2	134.2	11.2	112.8	10.4	92.9	14.7	55.2	9.3
Totals	9,087.3	15.1	5,951.7	9.7	6,007.3	10.2	5,556.7	10.4	5,519.9	10.9	5,539.4	11.8	5,175.6	12.0	4,701.9	11.7	4,203.7	11.2	3,846.9	10.8	3,579.7	11.0

*Equity as of Sept. 30, 1973. †Full years income estimated on the basis of income reported for the first 9 months of 1973.

Source: Compiled by Office of Tax Analysis, Department of Treasury, from Standard and Poor's Industrial Survey, Moody's Industrial Manual, quarterly financial statements filed with the Security Exchange Commission (10 Q Forms), cited in <u>Windfall or Excess Profits Tax</u>, Committee on Ways and Means, U.S. House of Representatives, 1974.

• Leading offshore producers accounting for 90.6% of total oil production in the Gulf of Mexico.

TABLE II-27

RATES OF RETURN FOR CHASE GROUP: 1971, 1972, 1973

		1973 ($ million)	1972 ($ million)	1971 ($ millio
1)	Average Borrowed & Invested Capital (a)	101,010	94,912	89,912
	Earnings (b)	14,099	8,889	9,086
	Return	14.0%	9.4%	10.1%
2)	Average Invested Capital (c)	75,546	71,730	67,849
	Earnings (d)	11,678	6,860	7,269
	Return	15.8%	9.7%	10.7%
3)	Average Total Assets	141,297	128,552	119,962
	Earnings (e)	12,091	7,116	7,534
	Return	8.6%	5.5%	6.3%
4)	Average Gross Fixed Assets	139,649	132,545	126,109
	Gross Operating Profit (f)	34,409	24,608	21,885
	Return	24.6%	18.6%	17.4%

(a) Includes long-term debt, preferred stock, common stock, surplus and equity of minority interests.

(b) Represents net income plus interest charges and income applicable to minority interests.

(c) Includes preferred stock, common stock and surplus.

(d) Represents net income.

(e) Represents net income plus income applicable to minority interests.

(f) Represents gross operating revenue less operating costs and expenses and taxes - other than income taxes.

SOURCE: "Financial Analysis of a Group of Petroleum Companies, 1972, 1973," Chase Manhattan Bank

TABLE II-28

1973 FINANCIAL FIGURES FOR OFFSHORE PRODUCERS[1]

(millions of dollars)

	Assets	Revenues	Net Income	Depletion Plus Depreciation	Cash Flow from Depr + Depl + Net Income
Shell Oil Co.	6,836	4,884	333	442	775
Continental	3,690	4,510	243	230	473
Exxon Co.	25,079	28,508	2,443	1,136	3,579
Chevron (subsidiary of SOCAL)[3]	8,650	7,762	844	406	1,250
Gulf Oil Corp.	10,074	10,007	800	610	1,410
Arco	5,964	3,983	270	256	526
Union Oil of Calif.	2,909	2,962	180	269	449
Texaco Inc.	14,761	11,835	1,292	551	1,843
Placid Oil Co. (1972)	162	70	15(approx.)	NA	NA
Kerr-McGee	867	728	63	54	117
ODECO[4]	284	89	19	16	35
Mobil Oil Corp.	10,690	12,756	849	493	1,342
Pennzoil	2,001	1,062	84	103	187
Signal (subsidiary of Burmah)	227.2	277.1	13.5	-4.7[2]	8.8
Tenneco[5]	5,230	3,910	230	223	453
Amoco (subsidiary of Standard of Indiana)[6]	7,018	6,468	511	448	959
Forest	291	33	-.037	16	16
Southern Natural Gas	891	453	54	40	94
Citgo	2,659	2,034.6	146.9	114.2	261.1
Sun Oil	3,690	2,286	230	228	458
Superior	660	173	34	30	64

1. Listed in descending order of offshore production (bbl/day)
2. Includes intangible development expense.
3. Chevron Oil (which conducts offshore production) is owned by Standard Oil of Calif. which are presented here.
4. Primarily offshore contract drilling company, owned 51% by Murphy Oil; its offshore production for its own account resulted in revenues of $15.2 million and a net loss before extraordinary income and income taxes of $5.6 million.
5. Total operations; Tenneco's oil operations accounted for 17% of operating revenues + 32% of income before taxes.
6. Figures are for Standard Oil of Indiana which owns Amoco.

Source: Annual reports; Dun & Bradstreet; phone conversations with oil companies.

Secretary Shultz's reasoning was that $7 per barrel of oil provides sufficient profits to oil companies both to return an adequate profit on current investments and to encourage and allow investments in new production sufficient to substantially reduce U.S. dependence on imported oil.

An analysis of President Ford's proposed windfall tax on crude prices by Platts Oilgram (January 20, 1975) concluded that the tax combined with deregulation of old oil prices would increase the average price of domestic oil from $6.97 to $7.86 per barrel. The rationale behind this price level was that "original government calculations reportedly showed a real oil price of between $7-8/bbl which provides all the incentives needed at this time for production and development activities, including enhanced recovery projects."[1]

The conclusion one should draw from this is that the U.S. Government is attempting to decide what is the "correct" level of profits for the oil industry and attempting to write its tax laws so as to bring about this level of profits. The objective seems to be to keep profits high, perhaps higher than in 1973 but not let them get "too high."

For the major companies and for the industry as a whole, profitability should continue to be strong for the next few years. It is possible that market conditions or government actions could change the picture, but changes in these areas will probably not affect profitability in the short run sufficiently for pollution control costs to be of significance to overall production. The greatest potential danger from changes in the current tax structure and the pollution control requirements is that investments in future production will be curtailed.

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[1] "Windfall" or Excess Profits Tax, U.S. House Committee on Ways and Means, 1974, p. 135.

4.3. Capital Requirements

The oil and gas industry will have to make investments in new exploration, development, and production well in excess of historic yearly levels in order to accelerate domestic production. These higher levels of capital expenditures raise the question of whether the industry will have access to the financing necessary to achieve the goals of increased domestic production. This issue was examined by the FEA and Arthur D. Little, Inc., in the Project Independence Report. As part of an analysis of the economic impact on the industry of the proposed effluent limitation guidelines, one must consider whether the added capital required for pollution control is of sufficient magnitude to approach capital availability limitations for the industry as a whole or for individual firms.

The FEA's analysis of the financial availability issue for the energy industries covered two main points, among others. Since World War II, 20 to 25 percent of total yearly business fixed investments have gone to the energy sectors. If the same percentage continued over the 11 year period 1975 to 1985, between $379 and $474 billion (in 1973 dollars) would be available for investment in the energy industries. FEA's estimate of the total investment required under an "Accelerated Supply" scenario was $454 billion, including investments in projects to come on line after 1985. The breakdown of investments by industry is shown in Table II-29. This estimate did not include outlays in the petroleum industry which are expensed for tax purposes such as intangible drilling and exploratory overhead costs nor did it include lease bonuses. They would amount to about $107.4 billion, according to FEA. For an energy

TABLE II-29

Comparison of Capital Requirements Estimates : Total Dollars
Cumulative 1975 - 1985
(Billions of 1973 Dollars)

	NPC (a)	NAE (b)	ADL (c)	FEA Accelerated Supply (Without Work in Progress) (d)	FEA Accelerated Supply
Oil and Gas (including refining)	133	149	122	80.3	98.4
Coal	8	18	6	10.6	11.9
Synthetic Fuels	10	19	6	.6	.6
Nuclear	7	93	84	105.3	138.5
Electric Power Plants (excluding nuclear)	137	53	43	50.5	60.3
Electric Transmission	42	125	90	92.1	116.2
Transportation	43	-	43	25.5(e)	25.5(e)
Other (f)	-	-	8	2.2	2.2
Total	380	457	396	367	454

(a) U.S. Energy Outlook, a summary report of the National Petroleum Council, Washington, D.C., December 1972 (Average of four supply cases)
(b) U.S. Energy Prospects, An Engineering Viewpoint, National Academy of Engineering, Washington, D.C., 1974
(c) Arthur D. Little estimates based upon an energy conservation scenario
(d) Assumes that imported oil price is $11/B. This column is considered roughly comparable to the NPC, NAE, and ADL estimates with the exception of oil and gas capital. The FEA estimates for oil, gas and refining do not include lease bonus payments, and outlays that are expensed for tax purposes (dry hole, intangible drilling and exploratory overhead costs); in order to make the FEA oil and gas figures comparable to the other estimates, $107.4 billion should be added to the FEA oil and gas estimates. Work in progress consists of investment spending made prior to 1985 for new plant and equipment which will not come on line until after 1985
(e) Does not include investments required for tanker fleets, but does include $5.5 billion targeted for Trans-Alaska oil pipeline
(f) Solar, Geothermal, Municipal Waste Treatment Plants, and Shale Oil

SOURCE: Project Independence Report, p. 282, FEA, November 1974 analysis are presented as a range of possible values rather than as point estimates.

It was not attempted to present future trends in costs and prices for the period considered. However, the results of the analysis do allow one to deduce how the estimated impact will change when costs and prices will change relative to the levels assumed for the analysis using [illegible] cost levels and a range of prices.

IV. IMPACT ASSESSMENT METHODOLOGY

IV.1. INTRODUCTION

This chapter describes the methodology whereby the economic impact of requiring added offshore water treatment equipment and reinjection facilities is assessed. As discussed in Chapter III, these facilities are expected to be required to meet the EPA treatment standards for 1977 and 1983 on offshore oil and gas producing installations.

Given the estimates of investment and operating costs for these treatment and reinjection facilities discussed in the previous chapter, and the estimates of the production economics prepared by ADL for the offshore areas under analysis, the potential impact of these proposed standards was evaluated in terms of:

- the loss of potential production due to premature abandonment of production units in 1977 and 1983.
- the loss of potential production due to a decrease in producing life of wells because of increased operating costs.
- the total capital required for investment in treatment and reinjection facilities.
- the average increase in costs per Bbl or MCF produced resulting from additional investment and operating costs.

In order to cope with the uncertainty associated with various factors in the analysis, "best estimates" of average values were made and then tested to determine the effects on results of possible values around this average by varying one parameter at a time. The results of the

TABLE III-5

Distribution of Different Treatment Technologies
Currently Being Used Offshore Louisiana
in Federal and State Waters [1]

Treatment Technology	Volume of Formation Water As % of Total	% Needing New Units	% of Treated Formation Water Needing New Units
Pits and Sumps [2]	32%	95%	30.4%
Tanks	27%	90%	24.3%
Plate	9%	100%	9.0%
Flotation*	24%	0%	.0%
Filters	8%	100%	8.0%
	100%		71.7%

(1) Source: by communication with the EPA.

(2) Onshore treatment of offshore produced formation water.

* Considered to be best practicable technology.

estimate of which types of technology are currently being used for treatment of formation water produced in Louisiana Federal and state waters (see Table III-5). According to their estimates, 24% of all the formation water produced in that offshore area is presently treated by flotation systems, considered to be the "best practicable". It can also be expected that not all of the other systems will have to be replaced by flotation systems. Some of these systems, given favorable conditions, will be able to meet the standards without any additional treatment equipment. Other systems will require modification at a lesser cost than the investment costs used in the impact analysis. It was not possible, however, to allow for all these factors in the analysis.

Therefore, the results of the analysis of the possible impact by the new treatment standards in 1977 should be considered to present a high cost estimate.

The EPA's estimates of the cost of drilling and equipping a 3,000 foot injection well in 1973 in the Gulf of Mexico were based on the average cost of $200,000 for drilling and equipping an oil well in that depth range.[1]

These costs increased from 1973 to 1974 by 35.6% according to a report by the Independent Petroleum Association of America's (IPAA) Cost Study Committee.[2] Using the IPAA index, the average cost of drilling and equipping a 3,000 foot well was escalated to be $270,000 by ADL. The maximum reinjection capacity of these wells was assumed to be 10,000 bbls/day based on the Brown & Root report. A 40,000 bbls/day reinjection plant then would require four wells.

Estimates of the cost of the platform deck area required for additional treatment and injection facilities in the EPA report were also based on Brown & Root's estimates. These estimates are applicable if an additional deck is required because of a lack of space on the existing platform and for situations where a new platform would be needed. Extra space requirements exceeding 1,000 square feet were assumed by Brown & Root to require a separate additional platform.

The economic impact analysis has assumed that all offshore production units would need to install the additional treatment systems discussed above. In reality, some production units will have treatment systems capable of meeting the 1977 treatment standards. The EPA has made an

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[1] Joint Association Survey of the U.S. Oil and Gas Producing Industry, Section I, Drilling Costs, 1973, American Petroleum Association, Feb. 1975.

[2] World Oil, Feb. 15, 1975.

TABLE III-4

POLLUTION ABATEMENT EQUIPMENT COSTS: OFFSHORE GULF OF MEXICO

(thousands of 1974 dollars per year)

(Energy costs based on natural gas @ $0.50/MCF)

Treatment Technology Type	Treatment[3] using Flotation Unit	Treatment[4] and Shallow Well Injection	Shallow Well Injection Only
Maximum Capacity: 200 B/D			
Inv. Costs: No extra space req'd.	64.0	439.0	358.0
Extra deck or platform (1)	108.0	496.0	404.0
Operating Costs	7.94	34.7	34.7
Energy Costs (2)	negl.	1.2	1.2
Max. Capacity: 1000 B/D			
Inv. Costs: No extra space req'd.	155.0	474.0	384.0
Extra deck or platform	219.0	536.0	435.0
Operating Costs	10.9	36.8	36.8
Energy Costs	0.03	5.89	5.86
Maximum Capacity: 5000 B/D			
Inv. Costs: No extra space req'd.	162.0	559.0	488.0
Extra deck or platform	253.0	642.0	599.0
Operating Costs	15.16	49.45	49.45
Energy Costs	0.32	29.45	29.29
Maximum Capacity: 10,000 B/D			
Inv. Costs: No extra space req'd.	255.0	698.0	593.0
Extra deck or platform	2016.0	2445.0	2340.0
Operating Costs	23.97	64.65	64.65
Energy Costs	0.63	58.9	58.6
Maximum Capacity: 40,000 B/D			
Inv. Costs: No extra space req'd.	555.0	1894.0	1670.0
Extra deck or platform	2372.0	3876.0	3340.0
Operating Costs	51.13	111.05	111.05
Energy Costs	1.3	117.8	117.2

(1) Extra deck space up to 1000 sq. ft.; extra platform space for area requirements larger than 1000 sq. ft.
(2) Energy costs based on natural gas @ 0.50/MCF. (3) BPCTCA in state & Federal waters. (4) BATEA in state waters.

SOURCE: Brown & Root Inc., additions E.P.A. updating and inflation adjustment by ADL.

The treatment systems considered to be the Best Practicable Control Technology Currently Available (BPCTCA) were the following:

- Separation by coalescence, using flow equalization (surge tanks), desanders and flotation, then discharge to surface water.
- Separation using flow equalization (surge tank), desanders and filters with disposal by shallow well injection.

The EPA Draft Development Document presented energy requirements in terms of annual costs only. To present these requirements in terms of annual natural gas requirements, ADL calculated the horsepower requirements for the treatment equipment using Brown & Root's estimates and expressed these horsepower requirements in terms of MCF natural gas equivalent. Horsepower requirements and resulting natural gas requirements for reinjection were calculated as well, using EPA's assumed average depth for injection wells of 3,000 feet.

The derivation of these horsepower requirements are discussed in Section 8, "Direct Energy Effectiveness of Treatment Equipment", of Chapter VI. The energy costs were calculated for diesel oil at $10 per barrel and for gas at $0.50 per MCF. Comparing these costs shows that energy costs will be about 3.5 times higher if diesel oil is used. Throughout the analysis, the natural gas-based energy costs were used.[1] Table III- 4 summarizes the abatement costs.

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[1] In terms of BTU equivalents: 1 bbl of diesel oil = 6 MCF natural gas, which @ $0.50/MCF would cost $3 or about 3.5 times less than 1 barrel diesel oil of $10, when using end-1974 prices.

III.3. COST OF POLLUTION ABATEMENT SYSTEMS

The investment and operating costs which are used in the economic impact analysis were prepared by the EPA based upon the previously referenced Brown & Root report. The EPA estimates, as presented in their Draft Development Document[1], added to the Brown & Root costs the additional costs of desanders and filters based on manufacturers' quotes with an allowance for installation costs for system capacities of:

- 200 bbls/day of processed water
- 1,000 bbls/day of processed water
- 5,000 bbls/day of processed water
- 10,000 bbls/day of processed water
- 40,000 bbls/day of processed water

The cost estimates were reviewed by ADL for consistency with the Brown & Root estimates. Further, to allow for inflation between 1973 and 1974, ADL multiplied the costs of all the treatment equipment by 1.24 using a Nelson inflation index indicating an inflation of 24% for Miscellaneous Equipment during that period. Estimates of operating costs had been made as a percentage of the capital costs based on percentages specified in the Brown & Root report. Consequently, operating costs were inflated by 24% as well.

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[1] EPA, October 1974: Draft Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Oil and Gas Extraction Point Source Category.

California State Waters

The California regulations applicable to offshore water disposal from offshore oil and gas production are water quality regulations, as opposed to uniform effluent quality regulations. The Regional Water Quality Control Boards have the responsibility to establish rules to protect underground and surface waters suitable for irrigation and domestic purposes and the "best interests of the neighboring property owners and the public" (California Laws for Conservation of Petroleum and Gas, 1973, Resources Agency of California, Sacramento, Calif., 1973, p. 15).

Since many of the offshore producing areas are near public beaches and recreation areas, the effluent standards which have been issued for the platforms required treatment to 20 ppm long-term average of oil and grease before discharge. Rather than treat to this level, most producers are reinjecting their formation water.

Alaska State Waters

Specific information has not been obtained on the Alaska state requirements for offshore formation water disposal.

Louisiana State Waters

Louisiana regulations of the offshore oil and gas platforms require effluent to be treated to a long-term average of 30 ppm of oil and grease.

Texas State Waters

The Texas regulations of offshore oil and gas platforms call for the issuance of permits for each platform based on the potential impact of the effluent on the local water quality. Many of the permits which have been issued have set the long-term average of oil and grease content in the effluent stream as 25 ppm.

III.2. CURRENT REGULATIONS

Offshore oil and gas operations are currently regulated by the contiguous state in state waters and by the USGS in Federal waters.

The applicable USGS regulations for the Federal waters in the Gulf of Mexico are the following:

> Wastewater disposal systems shall be designed and maintained to reduce the oil content of the disposed water to an average of not more than 50 ppm... On one day each month, four effluent samples shall be taken within a 24 hour period and determination shall be made on the temperature, suspended solids, settleable solids, pH, total oil content, and volumes of sample obtained... No effluent containing an excess of oil of 100 ppm of total oil content shall be discharged into the Gulf of Mexico.
>
> (OCS Orders 1 and 2, U.S. Dept. of the Interior, USGS, 1969, pp. 8-6)

The applicable USGS regulations for the Pacific region are slightly different:

> (a) Water discharged shall not create conditions which will adversely affect the public health or the use of the waters for the propagation of aquatic life, recreation, navigation, or other legitimate uses.
>
> (b) Wastewater disposal systems shall be designed and maintained to reduce the oil content of the disposed water to not more than 50 ppm... On one day each month, the effluent shall be sampled hourly for 8 hours and the following determinations shall be made on the composite sample: suspended solids, settleable solids, pH, total oil and grease content, and volume of sample obtained. Also, the temperature of each hourly sample shall be recorded.

This exemplary system was identified in the EPA's Draft Development Document, but the guideline specifies the effluent quality the system can achieve, not the system itself. If an offshore operator can achieve the effluent standard with a less expensive treatment system, he is free to do so.

The treatment system costs presented by EPA and updated by ADL are the costs of installing and operating the exemplary system. Based upon their analysis, the EPA has concluded that the exemplary treatment technology, separation by coalescence using flow equalization and dissolved gas flotation, should be both the 1977 BPCTCA treatment system and the 1983 BATEA treatment system. The effluent limitations are specified differently under the assumption that between 1977 and 1983 the operators will be able to increase the performance of their facilities. This assumption implies that the costs of complying with the 1977 and 1983 treatment requirements are identical. The operator in Federal waters who installs the equipment in compliance with the 1977 standard has no further capital cost as a result of the 1983 requirement. In state waters, the operators will have to go to reinjection in 1983.

TABLE III-3

DISTRIBUTION OF EFFLUENT SAMPLES FROM EXEMPLARY TREATMENT SYSTEMS

Guidelines	Long-Term Average	Maximum for Averages of Daily Values During 30 Days	Maximum of Values During One Day
1977 BPCTCA	27 ppm	48 ppm (95% of Daily Averages) 57 ppm (99% of Daily Averages)	72 ppm (95% of Daily Samples) 85 ppm (99% of Daily Samples)
1983 BATEA	27 ppm	30 ppm (95% of Daily Averages)	52 ppm (95% of Daily Samples)

SOURCE: U.S. Environmental Protection Agency platforms in state waters to end all discharge of produced formation water. The water can be piped ashore or reinjected into a subsea formation. In Federal waters, the BATEA requires that for any consecutive 30 days the averages of daily effluent samples not exceed 30 ppm 95% of the time. The guidelines also require daily maximums, as shown on Table III-2.

In addition to the BPCTCA and the BATEA guidelines, the EPA is proposing a New Source Performance Standard (NSPS) guideline applicable to all new wells in both state and Federal waters which is identical in its requirements to the BATEA guidelines except that its applicability begins in 1977.

New wells beginning production in state and Federal waters between 1977 and 1983 will have to comply with the NSPS guidelines. By 1983, all wells in state waters, new and existing, will have to go to reinjection of formation water. The new wells in Federal waters will continue to have to meet the BATEA and NSPS requirements.

The EPA used the survey from the Brown & Root report of effluent quality for different treatment systems now operating in the Gulf of Mexico and similar data from other sources to identify an "exemplary" abatement system. From the effluent samples the EPA structured a distribution of sample results from the exemplary treatment systems, as shown in Table III-3 . While the Agency believes treatment systems will produce effluent streams with a long-term average of 27 ppm of oil and grease, the guideline is written in terms of the maximum value that 95% of the averages of daily samples can have in any 30 days (48 ppm in 1977 and 30 ppm in 1983) and the maximum of 95% of the sample values during any one day (72 ppm in 1977 and 52 ppm in 1983).

TABLE III-2

PROPOSED EFFLUENT GUIDELINES

Guideline	Oil and Grease Limitations: Maximum for one day ppm[3]	Oil and Grease Limitations: Average of daily values for 30 consecutive days shall not exceed[4] ppm	Residual Chlorine ppm
BPCTCA			
state waters			
produced water	72	48	NA
deck drainage	72	48	NA
sanitary waste	NA	NA	1
federal waters			
produced water	72	48	NA
deck drainage	72	48	NA
sanitary waste	NA	NA	1
BATEA			
state waters			
produced water	—— no discharge	——	NA
deck drainage	52	30	NA
sanitary waste	NA	NA	1
federal waters			
produced water	52	30	NA
deck drainage	52	30	NA
sanitary waste	NA	NA	1
NSPS			
state waters			
produced water	—— no discharge	——	NA
deck drainage	52	30	NA
sanitary waste	NA	NA	1
federal waters			
produced water	52	30	NA
deck drainage	52	30	NA
sanitary waste	NA	NA	1

NOTE:

1. There shall be no discharge of free oil to the surface waters.
2. There shall be no discharge of floating solids as a result of sanitary waste discharge.
3. ppm (parts per million) is equivalent to a milligrams per liter (mg/l) concentration.
4. During the 30 days, 95% of the daily averages must not exceed the ppm standard.

SOURCE: U.S. Environmental Protection Agency

TABLE III-1

APPLICABILITY OF PROPOSED GUIDELINES

		1977		1983	
		Federal Waters	State Waters	Federal Waters	State Waters
Wells Producing Prior to 1977	- Guideline	BPCTCA[1]	BPCTCA	BATEA[2]	BATEA
	- Average of Daily Effluent Values for 30 Days Not to Exceed[4]	48 ppm	48 ppm	30 ppm	no discharge
Wells Beginning Production in 1977 and later	- Guideline	NSPS[3]	NSPS	NSPS	BATEA
	- Average of Daily Effluent Values for 30 Days Not to Exceed[4]	30 ppm	30 ppm	30 ppm	no discharge

1. BPCTCA is the Best Practicable Control Technology Currently Available guideline.
2. BATEA is the Best Available Technology Economically Achievable guideline.
3. NSPS is the New Source Performance Standard guideline.
4. During any consecutive 30 days, the daily averages of four effluent samples shall not exceed the specified value 95% of the time.

SOURCE: Environmental Protection Agency

Based upon a preliminary economic impact assessment among other factors, the initial guidelines were modified to the form reported here. Table III-1 lists the applicability of the guidelines to "new" and "existing" sources of effluent discharge. Over 30 wells may produce to one offshore platform. In most producing areas, the produced formation water from the wells is now separated from the oil and gas, treated and discharged to the ocean. Several producing platforms can pipe their production to one processing platform which discharges the formation water after treatment. Each of the discharges from a platform is a point source under the guidelines. In addition to the discharge of produced formation water, the rain water runoff and sanitary waste must be collected and treated on each platform. For these discharges, each platform is a point source.

Table III-2 lists the proposed guideline requirements. The guidelines separate the offshore producing areas into what are called the state and Federal waters. This is the jurisdictional distinction between those oil and gas fields whose development and operations are the responsibility of the contiguous states, as opposed to the U.S. Geological Survey. The EPA has adopted the state and USGS jurisdiction boundary to sub-categorize the offshore producing areas. The state and Federal waters boundary is approximately three miles from the shoreline.

In 1977, the BPCTCA guidelines will require the formation water produced from offshore wells in both state and Federal waters to be treated such that for any consecutive 30 days the averages of daily effluent samples (four per day) will not exceed 48 parts per million (ppm) of oil and grease 95% of the time. In 1983, the BATEA guideline requires

III. PROPOSED EFFLUENT LIMITATION GUIDELINES

III.1. PROPOSED EPA REGULATIONS

The U.S. Environmental Protection Agency is proposing a set of effluent limitation guidelines for the offshore oil and gas production industry. There are three sets of proposed effluent guidelines:

1. The Best Practicable Control Technology Currently Available (BPCTCA) (1977 implementation)
2. The Best Available Technology Economically Achievable (BATEA) (1983 implementation)
3. The New Source Performance Standard (NSPS) (1977 implementation)

In November 1974, the EPA issued the Draft Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Oil and Gas Extraction Point Source Category. This report presented an initial recommended set of guidelines based largely on a report[1] by Brown and Root, Inc., for the Offshore Operators Committee, an association of companies operating offshore oil and gas wells.

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[1] Determination of Beat Practicable Control Technology Currently Available To Remove Oil from Water Produced with Oil and Gas, March 1974.

the industry is moving beyond the "optimal" capital structure, the cost of capital will rise. Furthermore, given the fact that interest rates have been unusually high in 1973 and 1974, one might expect a decline in the cost of debt in the near future and a rise later.

The cost of capital has been used in this report to help evaluate whether firms will make the required investment to come into compliance with the proposed produced water treatment and reinjection requirements. The revenue stream resulting from making the investment and keeping the well in production has been discounted at the rate of the cost of capital. If the net present value of the investment in the treatment equipment is positive, the assumption has been made that the firm will make the investment rather than close in the well. If the industry cost of capital lies in the 10.4% to 12.0% range, theoretically, more firms will be able to make the investment. If the industry cost of capital lies in the 12.0% to 14.6% range, fewer firms can be expected to make the investment.

While 12% seems to be a realistic cost of capital value, the impact analysis has used 12%, 15%, and 20% to test the sensitivity of the results to different assumed or actual cost of capital values. The high end of the range has been chosen so that any possible errors in the analysis will be on the conservative side. A high cost of capital places the greatest burden on justification of investments which have a long time horizon.

are to buy a stock.

One method is to calculate the actual rates of return achieved by shareholders in the past, on the assumption that past rates of return are an accurate indication of shareholder expectations. The principal weakness of this approach lies in this very assumption. Given the increased uncertainties about oil prices, taxation, and regulation, the risk factors of the petroleum industry may seem to be changing, causing a corresponding change in expected rates of return. Thus, this method did not seem appropriate for this analysis.

A second method involves deriving the cost of equity from expectations about future dividends. This method is similar to the first one, but it involves a much longer time horizon. The principal difficulty in this approach is estimating future dividends. For a number of oil companies, the dividend payout ratio has decreased from 54% in 1969 to about 40% in 1973 and about 30% in 1974. Recent financial data show that for the first quarter of the years 1968-1975, profits as a percent of gross operating revenue have been steadily decreasing, with the exception of 1973 and 1974. In 1975, this percent was a record low. Thus, due to the difficulty of estimating future dividends, this method was not used.

A third method, which seemed most appropriate, involves calculation of a risk-adjusted rate of return. By owning a portfolio of stocks, an investor can partially eliminate the risk involved in owning one stock. That risk which cannot be diversified away is the covariance of the stock with the total market. This covariance is known as the firm's "beta" (β). For example, if a firm's stock has a beta of 1.0, when the total market moves up or down by 10%, this stock also moves up or down by 10%. If the beta were 0.5, the stock would move up or down by 5%. The beta of a stock is a substantially complete measurement

Thus, for the purposes of this analysis, the weighted average cost of capital will consist of a factor for the cost of debt and a factor for the cost of equity.

The mathematical expression generally used to calculate the weighted average cost of capital is as follows:

$$C = \frac{S}{V}(k_e) + \frac{B}{V}(k_d)(1-t)$$

where:

C = weighted average cost of capital

S = market value of the firm's stock

B = market value of the firm's debt

V = market value of the firm

k_e = cost of equity

k_d = cost of debt

t = marginal tax rate of the firm.

Estimate of the Cost of Debt

Approximating a firm's cost of debt is a fairly straightforward matter. Assuming that recent bond issues are representative of the firm's normal current and expected future debt costs, the cost of this recently acquired debt can satisfactorily be used as a surrogate for k_d in the cost of capital calculations. Recent petroleum bond issues (rated AAA to A) have had yields ranging from 9.0% to 9.5%. In this analysis, 9.5% is used as the cost of debt financing.

Because the range in bond yields is so small, a separate cost of debt has not been calculated for each firm in this sample of the petroleum industry.

Estimate of the Cost of Equity

Calculation of the cost of equity is the controversial element in a cost of capital analysis. There are several methods which one can use. The cost of equity is the rate of return which investors require on their money if they of investment risk; stocks which have higher betas have higher costs of equity. The cost of equity can be determined by using the following relations:

$$k_e = r_f + (r_m - r_f)\,\beta$$

where: k_e = cost of equity

r_f = risk-free rate; usually the U.S. Treasury Bill rate

r_m = total market return

β = beta of the stock.

The risk-adjusted method was used to calculate the cost of equity to be used in the economic impact analysis. The approach seemed most appropriate because it measures the risk of an investment while eliminating instability in individual stock prices. The risk-free rate has varied from 4.35% in 1971 to 7.01% in 1974. The total market return from 1928 to 1965 averaged 9.3%. The market return ranged from 10.9% in 1971 to 18.2% in 1974. Using the beta for each company and the appropriate values for the risk-free rate and the market return, the cost of equity was calculated for different investment periods from 1971 to 1974.

Estimate of the Cost of Capital for the Petroleum Industry

Given the range in the cost of equity for each firm and a cost of debt of 9.5%, a weighted average cost of capital was calculated. To arrive at an estimate of the cost of capital for the industry, several weighting methods were considered: weighting by total assets, total market value, total revenues, and offshore production (barrels/day). The arithmetic mean was also calculated. The estimated industry cost of the capital ranges from a low of 10.4% to a high of 14.4%, with an average of 12.4%. See Table II-39 for an example of the calculations.) Several oil companies contacted during this analysis indicated that they currently consider their cost of equity to be about 15%, implying a cost of capital of approximately 12%. Thus, an industry cost of capital of about 12% seems reasonable.

TABLE II- 39

EXAMPLE OF CALCULATION OF COST OF CAPITAL FOR 1971-1974[1]

Firm	Average Beta[2]	Cost of Equity (%)	Cost of Capital[3]
Atlantic Richfield	1.10	13.9	11.8
Cities Service	.90	12.5	10.0
Continental Oil	1.10	13.9	10.6
Exxon Corp.	.95	12.8	11.0
Gulf Oil Corp.	.90	12.5	10.1
Kerr-McGee Corp.	1.05	13.6	10.6
Mobil Oil Corp.	.95	12.8	11.0
Pennzoil Co.	1.35	15.7	8.3
Shell Oil Co.	.95	12.8	10.7
Standard Oil (Calif.)	1.05	13.6	12.1
Standard Oil (Ind.)	.85	12.1	9.9
Sun Oil Co.	.70	11.1	8.8
Texaco, Inc.	.95	12.8	10.0
Union Oil of Calif.	1.10	13.9	10.7

[1] During this period, the U.S. Treasury Bill rate averaged 6.05%, and the market return averaged 13.2%.

[2] Source, Value Line.

[3] Cost of debt is assumed to be 9.5%. Capital structure taken from Table II-38.

TABLE II-40

Oil Stock Prices

			12/31/74	
	High	Low	P/E Ratio	Closing
Atlantic Richfield	113 3/4	73	11	90
Cities Service	62 1/4	32 3/4	5	42 1/4
Continental Oil	58 1/2	29	5	44
Exxon Corp.	99 3/4	54 7/8	5	63 1/8
Forest Oil Corp.	11 1/8 (Bid)		11 1/2 (Asked)	
Gulf Oil Corp.	25 1/4	16	3	17 1/4
Kerr-McGee Corp.	92 1/2	47 1/8	16	71
Mobil Oil Corp.	56 1/2	30 5/8	3	36 1/4
ODECO (private?)				
Pennzoil	30 1/2	12 3/4	5	16 7/8
Phillips Petroleum	71 3/8	31 5/8	7	41 1/2
Placid Oil Co. (private?)				
Shell Oil Co.	72 7/8	30 1/4	6	46
Signal	22 3/4	12 3/4	2	13 1/4
Shelly Oil Co.	73	44 1/4	7	55 1/2
Southern Natural Gas--merged 5/73 into Southern Natural Resources, Inc.	55 1/2	27 1/8	7	41 7/8
Standard Oil (Calif.)	36 5/8	20 1/8	3	21 3/4
Standard Oil (Ind.)	45 7/8	39 7/8	6	42 1/2
Sun Oil Co.	61 3/4	33 3/4	4	35 3/8
Superior Oil Co.	304	134	15	172
Texaco, Inc.	32 7/8	20	3	20 7/8
Union Oil (Calif.)	56 3/4	27 1/4	4	38 1/2
Tenneco	24 3/4	16 3/4	6	23 1/4

Several words of caution about the cost of capital for an industry should be added at this point. Although 12% may be an appropriate general measure of the cost of capital of the petroleum industry, each company has a different capital structure and amount of risk associated with it. The cost of capital for the individual firms ranges from 8.3% to 16.0%. Rather than saying that the cost of capital of the industry is about 12.0%, it may be more appropriate to state that the cost of capital in the industry ranges from 8.3% to 16.0%.

Furthermore, interest rates and stock prices have fluctuated widely in the past 24 months. As shown in Table II-40, common shares of many of the off-shore producers had a price three to seven times earnings on December 31, 1974; however, this P/E ratio fluctuated greatly during the year.

In addition, the gap between internally generated funds and needed capital investments has widened considerably. Although gross revenues grew at an average rate of 19.2% between 1969 and 1974, available cash flow grew by only 14.7%. In 1974, while revenues increased nearly 75% from 1973, cash flow rose by only 31%. As a result, the petroleum industry must increasingly resort to outside financing. This trend is already evident. Between 1967 and 1972, the industry's ratio of long-term debt to total invested capital (long-term debt, preferred stock, and common stock) has risen from 0.18 to 0.28. It is expected to rise to 0.30 in the near future. Thus, one might also expect a rise in the cost of equity and the cost of capital for the industry. Traditional financial theory implies that the cost of capital is not independent of such changes in the capital structure. If the industry has not yet reached the debt limit, the increase in the cost of equity will be offset by the use of cheaper debt funds, resulting in a lower over-all cost of capital. However,

4.5. Cost of Capital

Introduction

One objective of a business organization is to maximize the market value of the firm's equity. When evaluating investments with this objective one can use the firm's cost of capital as a means of ranking investment alternatives. The cost of capital is the rate of return on investment projects which leaves unchanged the market price of the firm's stock. The cost of capital can be employed in a number of ways: 1) an investment project is accepted if its net-present value is positive when cash flows are discounted at the cost-of-capital rate; or 2) a project is accepted if its internal rate of return is greater than the cost of capital. Thus, the cost of capital represents a cut-off rate for the allocation of capital to investment projects.

The cost of capital is one of the most difficult and controversial topics in finance. There is wide disagreement, both in practice and in the financial literature, about how to calculate a firm's cost of capital.

Weighted Average Cost of Capital

There are a number of alternative sources of financing available to a firm; they include long-term debt, preferred stock, common stock, and retained earnings. If more than one type is present in the capital structure of the firm, the weighted average cost of capital reflects the interdependencies among the individual costs. For example, an increase in the proportion of debt financing will cause an increase in the risk borne by the common shareholder. The shareholder will then require a higher rate of return, implying a higher cost of equity.

As indicated in Table II-38, preferred stock does not represent a very high proportion of the capital structure of the leading offshore producers.

The oil industry now is in relatively strong financial condition. It anticipates making capital investments between now and 1983 far in excess of the investments required for compliance with the effluent guidelines. Thus, the investments in offshore water treatment and reinjection equipment cannot be regarded by themselves as being of importance to the financial strength or the required capital investment burden of the industry between 1975 and 1983.

Statements about the relative importance of a proposed regulation on one activity of an industry neglect the cumulative effects of other regulations, inflation rates, materials and labor costs, etc. When judging the impact of the effluent guidelines, one is at best making qualitative judgments about their importance relative to the total capital demands on the industry at the same time.

payments he is owed are covered by earnings. In 1972, which was the lowest recent profit year, the interest coverage ratio was 10.7. In 1973, the ratio was 14.5. If long-term lease arrangements and production payments are regarded as debt, the Chase Group's debt in relation to capital employed would have been 33% in 1973. While the precise figures are not reported by Chase, the interest coverage would fall to 9.3 in 1973 if the lease payments and production payments are regarded as yearly payment obligations similar to interest with an equal claim on revenues.

On the basis of their capital structure, the larger oil companies must be regarded as financially strong. Though hard to quantify, the companies seem to have the capacity for undertaking additional debt in the coming years. Whether this capacity will be sufficient along with other capital sources to meet the industry's needs or national energy goals is open to some question and beyond the intent of this brief discussion.

The role of the industry financial analysis in this economic impact study is to characterize the financial condition of the industry and report reputable estimates of the capital burden which the industry is likely to experience in the absence of the pollution abatement requirements. Given the financial condition and the other capital demands, this report should indicate whether the magnitude of capital expenditures required by the effluent guidelines will significantly distort the total industry capital demands or its financial condition.

the debt and equity percentages for 41 petroleum companies for 1972. On the average, equity accounts for 66.8% of total capitalization. One also sees in Table II-37 the predominance of retained earnings in net worth. About 75% of shareholders' equity is retained earnings. In 1964, the retained earnings were 62% of equity.

Although the ratio of long-term debt to equity has been rising to its present level of about 28%, it is below what one would reasonably expect to be an upper limit of debt capacity for a profitable industry. Each year Dun's Review publishes financial ratios for 71 categories of manufacturing firms. For 1973, the average of the ratios of total debt to net tangible worth for these firms was 103%. For the Chase Group of petroleum companies, the comparable ratio was about 78%. The concept of an "upper limit" is an abstraction referring to a range which is viewed as meeting some set of criteria by the banking and investment community and applicable to a particular industry. A firm which takes on significantly more debt than other firms in its industry exposes its debtors to higher risks than other firms in the industry. With such a high debt portion of its capital structure, a company may face higher interest rates, lower bond ratings, problems of raising equity or possibly the non-availability of funds.

In 1973, the Chase Group had long-term debt of $22.7 billion. In comparison, the Group's working capital was $19.6 billion and their net fixed assets were $79.6 billion. Total net assets were $79.1 billion. The ratio of debt to total capitalization is .47 as compared with about .6 as characteristic of manufacturing industries. One can also look at the interest coverage by before tax income. The calculation is before tax income plus interest payments divided by the interest payments. From the creditor's viewpoint, this ratio indicates how much the interest

TABLE II-38

PETROLEUM INDUSTRY CAPITALIZATION, 1972

		CAPITAL STRUCTURE		
		Debt	Equity	Other[1]
•	Pennzoil Co.	55.6%	35.7%	8.7%
	Apco Oil Corp.	44.0	54.9	1.1
	Amerada-Hess Corp.	44.1	55.2	.7
	Ashland Oil, Inc.	36.1	53.4	10.5
•	Atlantic Richfield Co.	21.4	77.3	1.3
	Belco Petroleum Corp.	40.3	59.7	-
	British Petroleum Co.	37.1	59.8	3.1
•	Cities Service	27.9	69.3	2.8
	Clark Oil and Refining	34.7	61.0	4.3
	Commonwealth Oil	44.2	46.8	9.0
•	Continental Oil	28.6	66.7	4.7
•	Exxon Corp.	17.0	79.6	3.4
	Gen. Am. Oil of Texas	.5	99.5	-
	Getty Oil Co.	6.3	80.5	13.2
•	Gulf Oil Corp.	25.5	71.2	3.3
	Gulf Oil Canada	18.7	70.8	10.5
	Helmerich and Payne	48.0	52.0	-
	Imperial Oil, Ltd.	14.6	74.1	11.3
•	Kerr-McGee Corp.	18.5	71.5	10.0
	Louisiana Land and Expl.	30.5	69.5	-
	Marathon Oil Co.	28.8	71.2	-
	Mesa Petroleum	58.5	41.1	.4
•	Mobil Oil Corp.	16.8	79.9	3.3
	Murphy Oil Corp.	35.0	42.1	22.9
	Occidental Petroleum	54.0	44.7	1.3
	Pacific Petroleums Ltd.	32.4	67.6	-
•	Phillips Petroleum Co.	29.6	68.0	2.4
	Quaker State Oil	25.4	68.4	6.2
	Royal Dutch Petroleum	20.4	68.6	11.0
•	Shell Oil Co.	26.0	74.0	-
	Shell Transport and Trad.	21.8	66.4	11.8
•	Skelly Oil Co.	11.1	88.9	-
•	Standard Oil (Calif.)	16.5	83.5	-
•	Standard Oil (Ind.)	20.7	73.9	5.4
	Standard Oil (Ohio)	26.9	68.8	4.3
•	Sun Oil Co.	22.8	69.8	7.4
•	Superior Oil Co.	22.3	77.7	-
	Tesoro Petroleum	24.8	71.7	3.5
•	Texaco, Inc.	13.9	73.2	12.9
•	Union Oil of Calif.	26.3	68.2	5.5
	United Refining Co.	36.9	63.1	-
	Average	28.4	66.8	6.5

1. Includes: Preferred Stock, Deferred Taxes, and Minority Interest.

• *Leading offshore producers (representing 92.2% of total offshore production)*

SOURCE: "Value Line", cited in Opinion 699, Appendix E, Federal Power Commission, 1974

TABLE II-37

BALANCE SHEET OF CHASE GROUP, 1973, 1972, 1971

	12/31/73 ($ million)		12/31/72 ($ million)		12/31/71 ($ million)	
Assets						
Current Assets	56,149	37.3%	42,686	32.3%	39,586	31.7%
Investments and Advances	10,386	6.9	10,266	7.8	9,900	7.9
Property, Plant and Equipment (a)	79,613	52.9	75,097	56.8	71,740	57.4
Other Assets	4,268	2.9	4,134	3.1	3,673	3.0
Total Assets	150,416	100.0	132,183	100.0	124,899	100.0
Liabilities and Net Worth						
Current Liabilities	36,502	24.2	28,540	21.6	25,656	20.5
Long-Term Debt	22,727	15.1	21,858	16.5	20,523	16.4
Deferred Credits	5,711	3.8	4,587	3.5	3,804	3.0
Other Reserves	2,821	1.9	2,411	1.8	2,078	1.7
Minority Interests	3,274	2.2	3,031	2.3	2,941	2.4
Net Worth:						
Preferred Stock	315	0.2	404	0.3	429	0.3
Common Stock	10,455	7.0	10,511	7.9	10,530	8.4
Capital Surplus	8,597	5.7	9,061	6.9	8,800	7.1
Earnings Reinvested in Business	60,014	39.9	51,780	39.2	50,138	40.2
Shareholders' Equity	79,381	52.8	71,756	54.3	69,897	56.0
Total Liabilities and Net Worth	150,416	100.0	132,183	100.0	124,899	100.0

(a) After deducting accumulated reserves of $64,060 million in 1973, $60,530 million in 1972, and $58,562 million in 1971.

SOURCE: "Financial Analysis of a Group of Petroleum Companies, 1973, 1972", The Chase Manhattan Bank far more important to the overall profitability and access to capital of the industry than the proposed pollution control standards.

- While FEA has said that the industry can reasonably be expected to finance itself, knowledgeable people have questioned the conclusion, and it should be used here with caution.

- Over the period 1977-1983, the oil and gas industry will make capital investments of approximately $6-$7 billion per year on the exploration, development, and production of offshore oil and gas. Total industry capital investment during the period will be about $14-$18 billion per year.

4.4. Capital Structure

The petroleum industry has historically depended primarily on internally generated funds rather than borrowed capital. Table II-37 is the balance sheet for the Chase Group for 1971, 1972, and 1973. Long-term debt plus deferred credits and minority interests makes up 22%-23% of total capitalization for the three years and is about 40% of the value of equity. The portion of total capitalization which is longer-term debt has been gradually rising since 1964, when it was about 13%. Although long-term lease arrangements and production payments do not appear on the balance sheet, they are sources of additional capital. If they were regarded as debt, the Group's debt in relation to capital employed would have been 33% in 1973 and 22% in 1964. Table II-38 lists

TABLE II-36

TYPICAL YEARLY CAPITAL EXPENDITURES
OF SEGMENTS OF THE OIL INDUSTRY IN THE U.S.

Offshore Oil and Gas Production	\$6-\$7 billion per year
Onshore Oil and Gas Production	\$3-\$4 billion per year
Other Capital Expenditures (refineries, pipelines, marketing, etc.)	\$6-\$7 billion per year
Total	\$14-\$18 billion per year

SOURCE: Arthur D. Little, Inc., estimates

TABLE II-35

EXPLORATION AND DEVELOPMENT EXPENDITURES
IN THE U.S.: 1972 AND 1973

Expenditure	1973 ($ million)	1972 ($ million)
Lease acquisition		
Onshore	500	200
Offshore	3,100	2,275
Producing wells	2,705	2,330
Dry holes	985	935
Geological and geophysical expense	675	575
Lease rentals	175	165
Total	8,140	6,480

SOURCE: "Capital Investments in the World Petroleum Industry, 1973", Chase Manhattan Bank

TABLE II- 34

ESTIMATED CAPITAL AND EXPLORATION EXPENDITURES

	1967	1968	1969	1970	1971	1972	1973
	Million Dollars						
WORLD							
Crude Oil and Natural Gas	5,595	6,875	7,075	6,650	6,520	9,590	12,415
Natural Gas Liquids Plants	405	585	465	580	695	515	510
Pipe Lines	860	1,080	910	850	1,200	1,230	1,230
Tankers	1,255	1,650	2,050	2,575	2,875	3,775	6,550
Refineries	2,585	2,950	3,210	4,000	4,755	4,955	4,865
Chemical Plants	1,565	1,480	1,310	1,525	1,535	1,350	1,175
Marketing	2,705	2,665	2,805	3,220	3,380	2,825	2,480
Other	605	615	550	725	840	710	770
Total Capital Expenditures	15,575	17,900	18,375	20,125	21,800	24,950	29,995
Geological & Geophysical Expense & Lease Rentals	1,190	1,330	1,380	1,340	1,395	1,540	1,700
COMBINED	16,765	19,230	19,755	21,465	23,195	26,490	31,695
UNITED STATES							
Crude Oil and Natural Gas	3,750	4,675	4,525	4,110	3,185	5,740	7,290
Natural Gas Liquids Plants	275	250	225	225	200	175	150
Pipe Lines	360	425	300	450	550	300	450
Tankers	40	50	100	100	125	125	100
Refineries	775	800	950	1,075	1,050	900	1,050
Chemical Plants	825	650	575	550	500	450	425
Marketing	1,250	1,150	1,250	1,450	1,350	1,100	850
Other	375	350	250	265	290	260	325
Total Capital Expenditures	7,650	8,350	8,175	8,225	7,250	9,050	10,640
Geological & Geophysical Expense & Lease Rentals	615	715	725	665	715	740	850
COMBINED	8,265	9,065	8,900	8,890	7,965	9,790	11,490

SOURCE: "Capital Investments of the World Petroleum Industry, 1973," Chase Manhattan Bank

As a comparison, Chase publishes a survey entitled "Capital Investments of the World Petroleum Industry" each year. The most recent year covered is 1973. Table II-34 lists the capital expenditures for the U.S. and for the world for 1962 through 1973. Table II-35 is a breakdown of exploration and development expenditures in the U.S. for 1972 and 1973.

Chase lists in Table II-34 the sum from Table II-35 of expenditures for lease acquisition, producing wells, and dry holes. The remaining items were not counted as being capitalized. This pattern may not always hold true, particularly for dry holes and geological and geophysical expenses.

The estimates of expenditures by the Journal and by Chase are significantly different for the exploration and production categories. However, they give general guidance as to the level of expenditures one should use as a point of comparison with the pollution control capital expenditures. Table II-36 lists the general comparison values which can be used in the impact analysis.

There are three points one should conclude from this discussion of oil industry financial resources:

- The profitability of the oil industry, its tax liability, and its ability to finance itself are critically dependent on government policy and actions. Powerful political groups are keenly interested in changing government policies to make the industry more or less profitable. These influences are

TABLE II-33

ESTIMATED CAPITAL AND EXPLORATION EXPENDITURES OF U.S. OIL INDUSTRY

(1972-1975)

	1975 (budgeted) ($ million)	1974 (estimated) ($ million)	1973 ($ million)	1972 ($ million)
Exploration and Production				
Drilling and Exploration	8,034.0	7,657.0	6,660.8	5,717.6
Production	2,104.1	2,005.5	1,734.8	942.4
OCS lease bonus	5,500.0	5,024.0	3,082.0	2,258.8
Total	15,138.1	14,686.5	11,477.6	8,918.8
Other Expenditures				
Refining	3,127.8	1,974.7	1,103.8	946.6
Petrochemicals	1,643.1	816.3	269.1	300.6
Marketing	1,106.0	780.7	914.5	1,148.9
Natural Gas Pipelines	988.0	541.0	600.0	578.0
Crude Products Pipelines	2,318.0	1,096.0	150.0	94.0
Other Transportation	240.4	148.7	152.9	175.0
Miscellaneous	1,684.0	1,073.3	646.9	570.0
Total	11,106.9	6,430.7	3,837.2	3,813.1
Total Expenditures	26,245.4	21,117.2	15,314.8	12,731.9

SOURCE: Oil and Gas Journal, Feb. 3, 1975

Looking ahead to the next ten years, one sees conflicting currents. Higher crude and natural gas prices have allowed large increases in profits per barrel. On the other hand, the high prices will dampen demand and also raise public concern about excess oil company profits. One must also consider that 1973 and 1974 saw foreign operations generating the largest earnings. This, combined with price controls and excess profits taxes in the U.S., may discourage investment in U.S. operations rather than even a continuation of historic patterns.

As has now been said several times, it is very difficult to project profitability or capital expenditures patterns for the industry over an extended period of time, given the economic and political uncertainties of the next few years. While it is probably inaccurate to simply project trends from the last ten years into the next ten, it is equally wrong to extrapolate the trends of the last year or two which saw the devaluation of the dollar and large inventory profits. The Oil and Gas Journal collects capital expenditure statistics each year from 150 firms which are then proportionately projected to the whole industry on the basis of the companies' portion of total industry crude production. Table II-33 lists the results for 1972, 1973, and 1974 plus a projection for 1975. The Journal does not make a clear distinction between expenditures which companies capitalize and those they do not. The drilling and exploration expenditures probably include significant funds which are normally expensed by the companies.

TABLE II-32

SOURCE AND USE OF CAPITAL FOR CHASE GROUP IN 1973

	$ million	(%)
Funds Available From:		
Cash flow	21,230	(73.4)
Long-term debt issued	4,381	(15.2)
Preferred and common stock issued	432	(1.5)
Sales of assets and other transactions	2,867	(9.9)
Total	28,910	(100.0)
Funds Used For:		
Capital expenditures	14,637	(50.6)
Investments and advances	382	(1.3)
Dividends to company shareholders	3,965	(13.7)
Dividends to minority interests	157	(0.6)
Long-term debt repaid	3,698	(12.8)
Preferred and common stock retired	570	(2.0)
Total	23,409	(81.0)
Change in Working Capital	5,501	(19.0)

SOURCE: "Financial Analysis of a Group of Petroleum Companies, 1973", The Chase Manhattan Bank

TABLE II-31

CASH FLOW OF CHASE GROUP FOR 1973

	$ millions	
Net income	11,678	(55%)
Write-offs (incl. depreciation and depletion)	8,345	(39%)
Other non-cash charges (net)	1,207	(6%)
Total Cash Flow	21,230	(100%)

SOURCE: "Financial Analysis of a Group of Petroleum Companies, 1973", The Chase Manhattan Bank

If the $34.1 billion lease bonus payments of Table II-30 are added into the total capital requirements in Table II-29, the FEA Accelerated Supply estimate rises to $488.1 billion. Geological and geophysical expenses can add another $5 to $8 billion in capital requirements over the period. The $493-496 billion is beyond the range of $379-474 billion which FEA estimated would be available from traditional financing patterns for the energy industries.

A definitive analysis of capital requirements or capital availability for the oil and gas industry is beyond the scope of this study. For the purposes of this analysis, one should note FEA's conclusion, but it should be used with caution.

The Chase analysis of 30 major oil companies cited earlier compiled the sources and uses of funds by the companies. Table II-31 lists the sources of cash earnings for 1973. Thirty-nine percent of the cash flow is from various capital recovery mechanisms such as depreciation and depletion. Table II-32 lists all of the sources of capital and their disposition for the year. The effective end of depletion allowances for the large oil and gas companies has reportedly had a major impact on cash generation for the companies. Industry-wide data, such as for the Chase Group, is not yet available for the first quarter of 1975; however, reports by individual firms have identified the end of the depletion allowance as having a major effect on cash generation.

TABLE II-30

Estimates of Petroleum Industry Capital Requirements
(Billions of 1973 Dollars)
1975 to 1985

	FEA Accelerated Supply Without Work-in-Progress	FEA Accelerated Supply Adjusted for Work-in-Progress
Oil & Gas (1)	80.3	98.4
Oil & Gas Capital Outlays That Are Expensed (2)	73.3	73.3
Transportation:		
Oil & Product Pipelines	11.9	11.9
Gas Transmission	5.5	5.5
Lease Bonus Payments	34.1	34.1
TOTAL	$205.1	$223.2

(1) Includes: Oil, Natural Gas, and Refinery Output Numbers.
(2) Includes: Dry hole, intangible drilling, and exploratory overhead costs.

SOURCE: Project Independence Report, p. 290, FEA, November 1974 conservation scenario, the total capital requirements were estimated to be $396 billion, including expensable outlays. The conclusion was drawn by the report that, as a whole, the energy industries would have access to adequate capital, assuming a simple continuation of their past share of investment funds.

For the oil and gas industry, including refining, FEA estimated that $98 billion would be required over the 11 year period for the Accelerated Supply case. Table II-30 shows these estimates plus the expensed items. FEA believes this level of investment can be entirely financed from internal funds with additional funds available for projects outside the oil and gas industry.

This conclusion is disputed by many inside and outside the oil industry. One of the major exceptions that is made to the FEA analysis is the treatment of lease bonuses. In Table II-29, FEA has not included $34.1 billion that FEA expected to be paid for lease bonuses from 1975 to 1985. Moreover, this value is probably too low since payments in 1974 were $5.0 billion and are projected by the Oil and Gas Journal to be $5.5 billion in 1975 (February 1975).

- Investment in treatment systems in 1977 and in reinjection system in 1983 (Strategy 1)
- Investment in treatment system in 1977 and abandonment in 1983 (Strategy 2)
- Investment in reinjection in 1977 (Strategy 3).

Having calculated the investment requirements and present values of net after tax cash flows for these three different strategies, the strategy with the highest net present value is selected. For that strategy the loss in potential production is calculated and stored together with the investment for 1977 and 1983.

When all leaseblocks have been evaluated in this manner, the following information is printed out:

- Total annual loss in potential production of oil and associated gas and condensate by either early abandonments in 1977 and 1983 or by the decrease in producing life of production units.
- Cumulative total of potential production lost.
- Annual potential production and cumulative total potential production.
- Maximum annual water production and cumulative total water production.
- Total investment in 1977 and 1983.
- Percentage of total investment in 1977 in reinjection facilities.
- Average annual operating costs per barrel or per MCF produced and average addition to operating costs per unit produced due to treatment and/or reinjection.

The period covered in the analysis extended up to the year 2000.

Adding the annual treatment cost to existing operating cost levels the economic life of the leaseblock is again calculated and the decrease in that economic life by the added operating costs is established.

To determine whether the investment will be paid for by the remaining production the annual after tax cashflow is calculated for each of the remaining years post 1977. If the present value of that after tax cash flow happens to be smaller than the investment required in 1977, then the loss in potential production due to early abandonment of the leaseblocks' production units is calculated. Otherwise the loss in potential production due to a decrease in the leaseblocks' producing life is calculated and is stored together with the information on the required investment. When all leaseblocks have been analyzed, output tables are printed out which show the total annual production foregone for all leaseblocks by either early abandonments in 1977 or by decreases in the producing life, plus information on the total investment required in 1977.

For state waters the analysis performed by the program is more complicated because of the reinjection requirement in 1983. Using the same criteria as in federal waters, three possible investment strategies are evaluated and compared.

First, however, it is determined whether the producing life of the leaseblock extends beyond 1983. If this turns out not to be the case, then the investment in treatment in 1977 is evaluated in exactly the same manner as described above for federal waters.

If the producing life of the leaseblock extends beyond 1983, then the after tax cashflows of the following three strategies are calculated (See Figure IV-8):

FIGURE IV-7
Computer Flow Diagram
State Waters

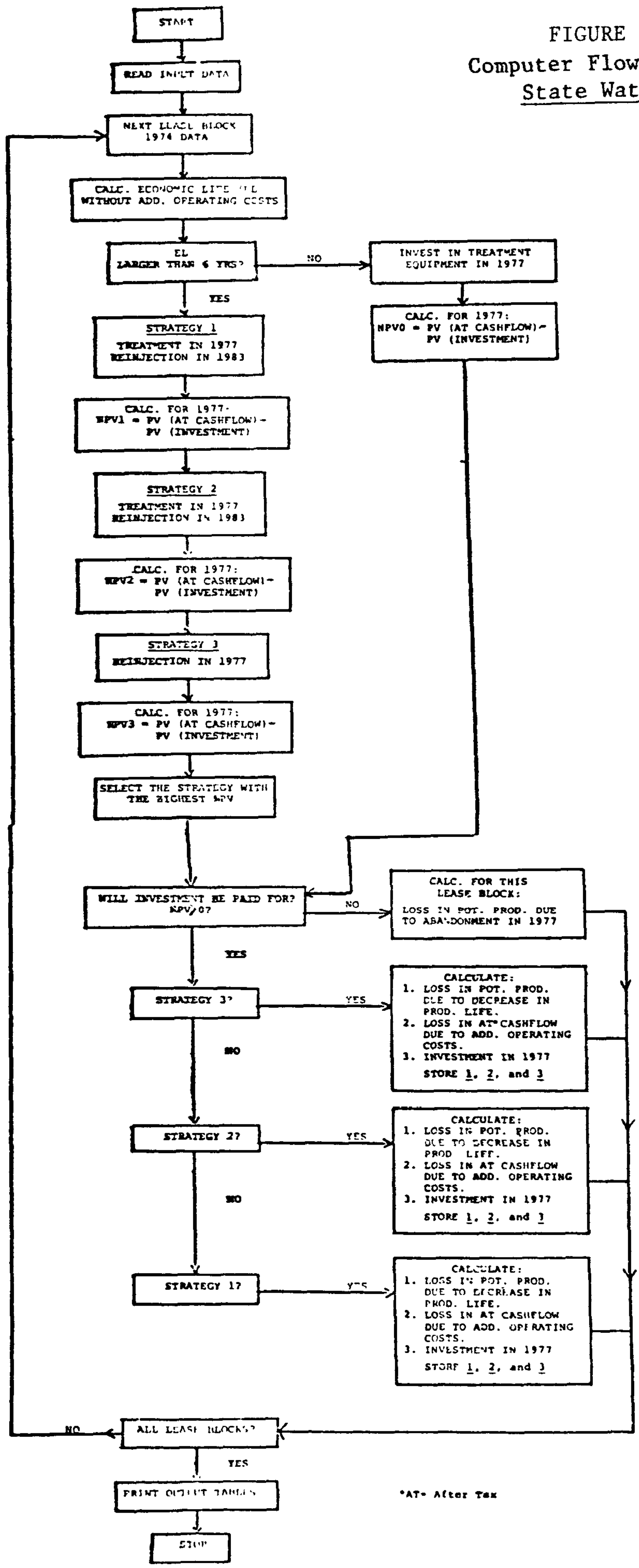
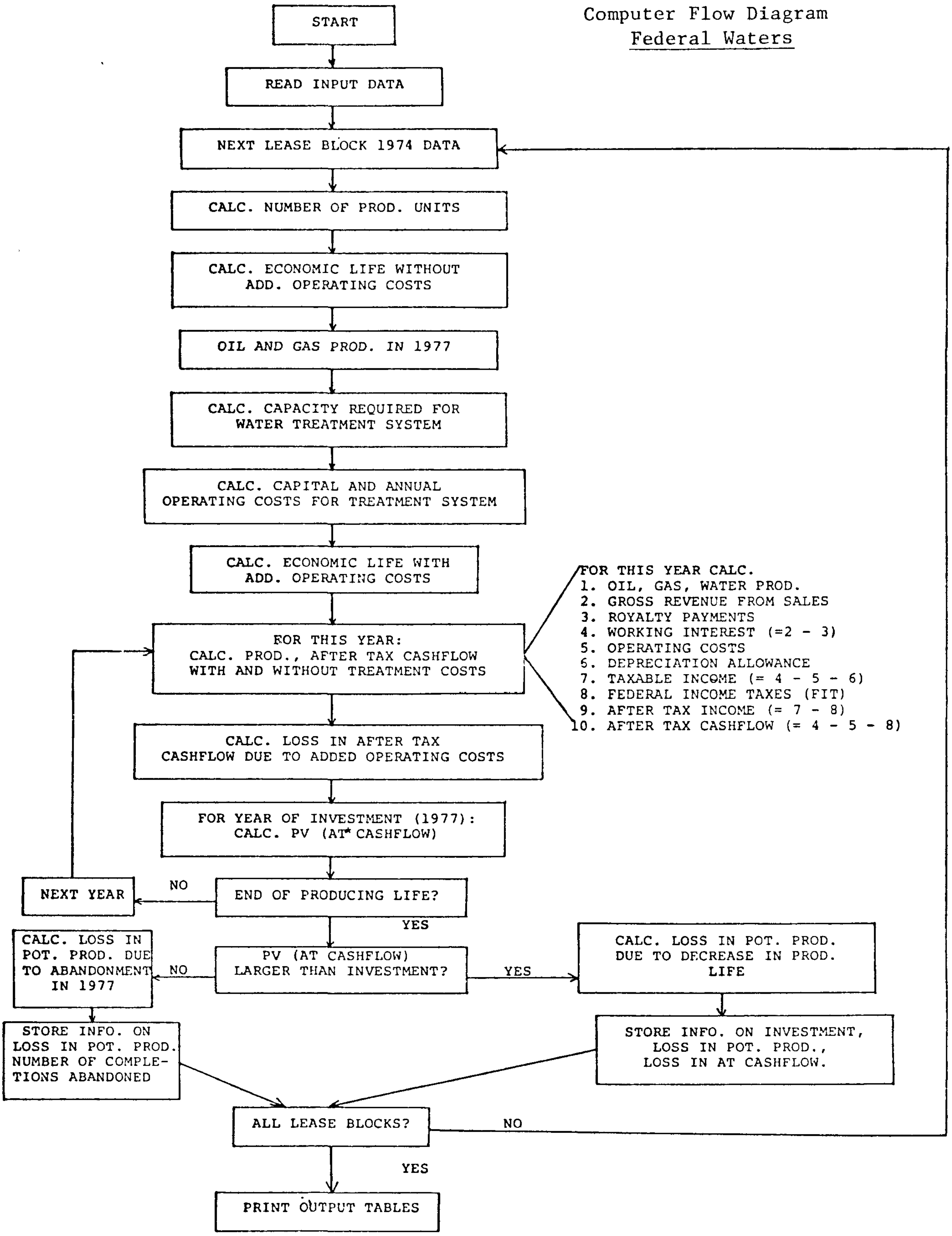


FIGURE IV-6
Computer Flow Diagram
Federal Waters



*AT= After Tax

IV.6. COMPUTER PROGRAM

A computer program was developed to facilitate the calculations for the numerous cases which needed to be evaluated.

The same program could be used for the impact analysis in state waters and federal waters, in spite of a considerable difference in the complexity of the analysis required for those areas.

The general flow diagram presenting the different steps in the calculations required for the federal waters and state waters are shown in Figure IV-6 and Figure IV-7 respectively. The program first reads the data for a leaseblock, which consist of information on:

- the number of producing completions
- the number of platforms
- the total daily production of (1) oil, associated gas and water or (2) gas, condensate and water.

Then the economic life is calculated for that leaseblock, using a parameter value for the annual decline rate and the future crude oil or gas price.

The operating cost function, described in the previous pages, is used to calculate the average annual per-barrel (or per-MCF) operating cost, which then is used to determine the number of years over which the production will decline until these per-barrel operating costs equate the going "price" per barrel of crude or per MCF of gas.

Annual production volumes of oil and gas in 1977 are projected and the average capacity for water treatment facilities on the production units in the leaseblock are calculated. Based on that capacity estimate, investment costs and annual operating costs are estimated for these treatment systems.

Since most pipelinesusually transport the production of more than one production unit.

The wellhead price used in the analysis therefore should be considered as representing the price which the operator would get at the point of sale decreased by the transportation costs between the production unit and that point of sale.

The results of the impact analysis have been tested for their sensitivity to changes in this "wellhead" price. Given the range -- from \$5.25 to \$11.00 -- over which this "wellhead" price was changed in these sensitivity tests, it can be assumed that any error by not allowing for a transportation charge in the base case price of \$7.50 lays well within the range of results obtained by these sensitivity tests.

- Taxable Income= Gross Revenues - Royalties - Operating Costs - Depreciation
- Annual depreciation charges were calculated using the unit of production method (1)

IV.5 NO ALLOWANCE FOR COSTS OF TRANSPORTING OIL AND GAS ONSHORE

The impact analysis was performed, assuming a wellhead price for oil as well as for gas. This assumption can be criticized as being artificial in the case of oil, where the producing company usually co-owns and co-operates the pipeline to the point of sale onshore, thus incurring additional costs.

It was not possible to find a cost formula which would reflect the considerable differences in transportation charges for the different production units. These differences are the result of differences in distances, different volumes transported and use of one pipeline for several production units. Also, it was felt that the pipeline costs would not play an important role in the decision of an operator to continue to produce a certain production unit or not.

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(1) The unit of production method requires estimates of the total cumulative production, QCUM, over the life of the production unit and calculates an annual depreciation factor, DEPF, by dividing total investment, TI, by this cumulative production:

$$DEPF = TI/QCUM$$

Annual depreciation charges, DCHARGE, are then calculated by multiplication of the annual production, Q_t, by this factor:

$$DCHARGE = DEPF \cdot Q_t$$

IV.4. AFTER TAX CASH FLOWS FOR EACH PRODUCTION UNIT

The annual after-tax cash flows, which were needed for the present value analysis of the investments required for the new water treatment and/or injection facilities, were calculated in the following manner:

In the case that taxable income was positive:

Annual after-tax cash flows = gross revenue - royalty payments - operating costs - taxes

In the case that taxable income was zero or negative:

Annual after tax cash flows = gross revenue - royalty payments - operating costs.

- Gross Revenue = Annual Production of Oil x Wellhead Price + Annual Production of Gas x FPC Gas Ceiling Price (50¢/MCF)
- Royalties = 16.7% of Gross Revenues
- Operating costs were calculated as described in the previous section
- Taxes = 48% of Taxable Income

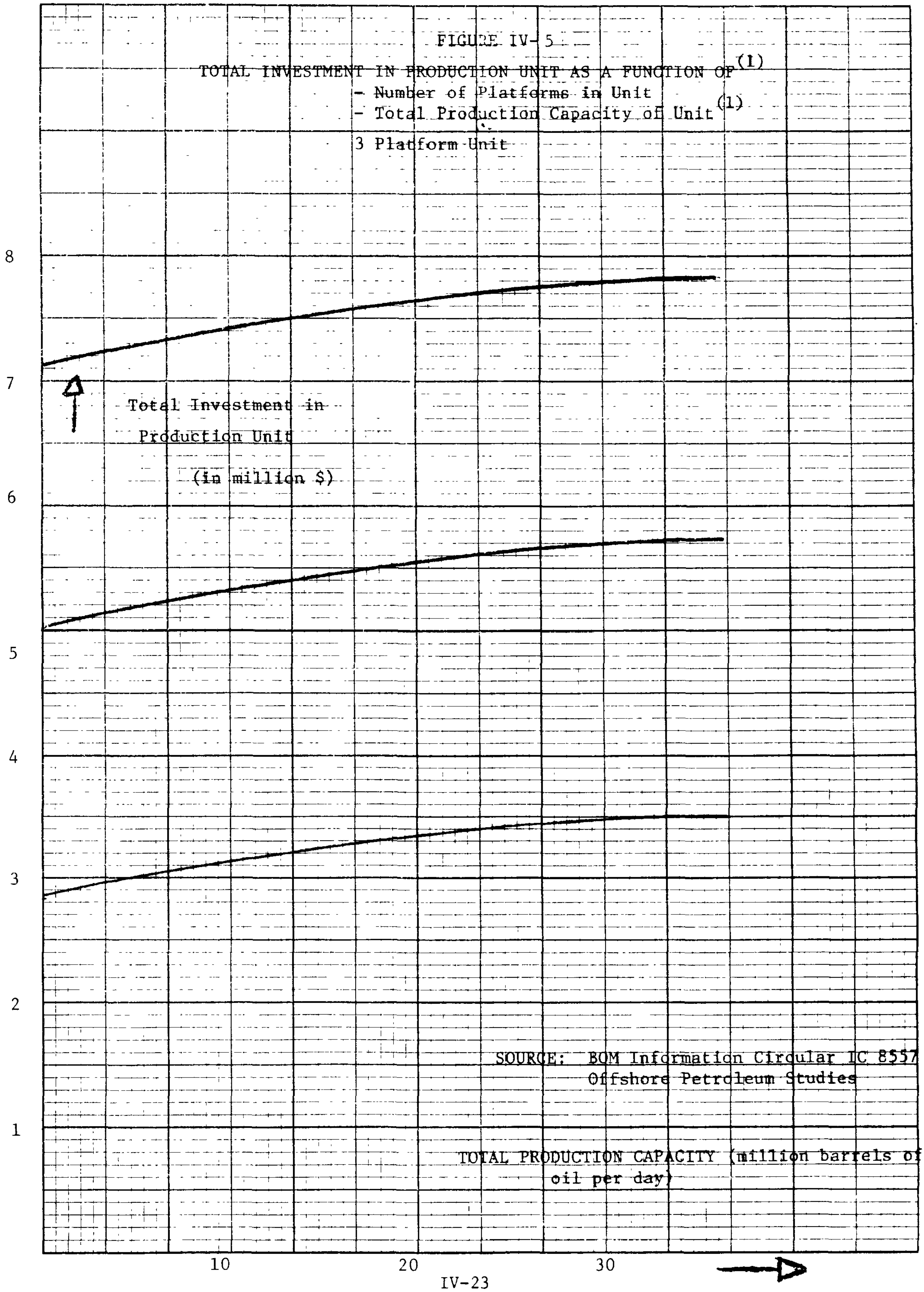
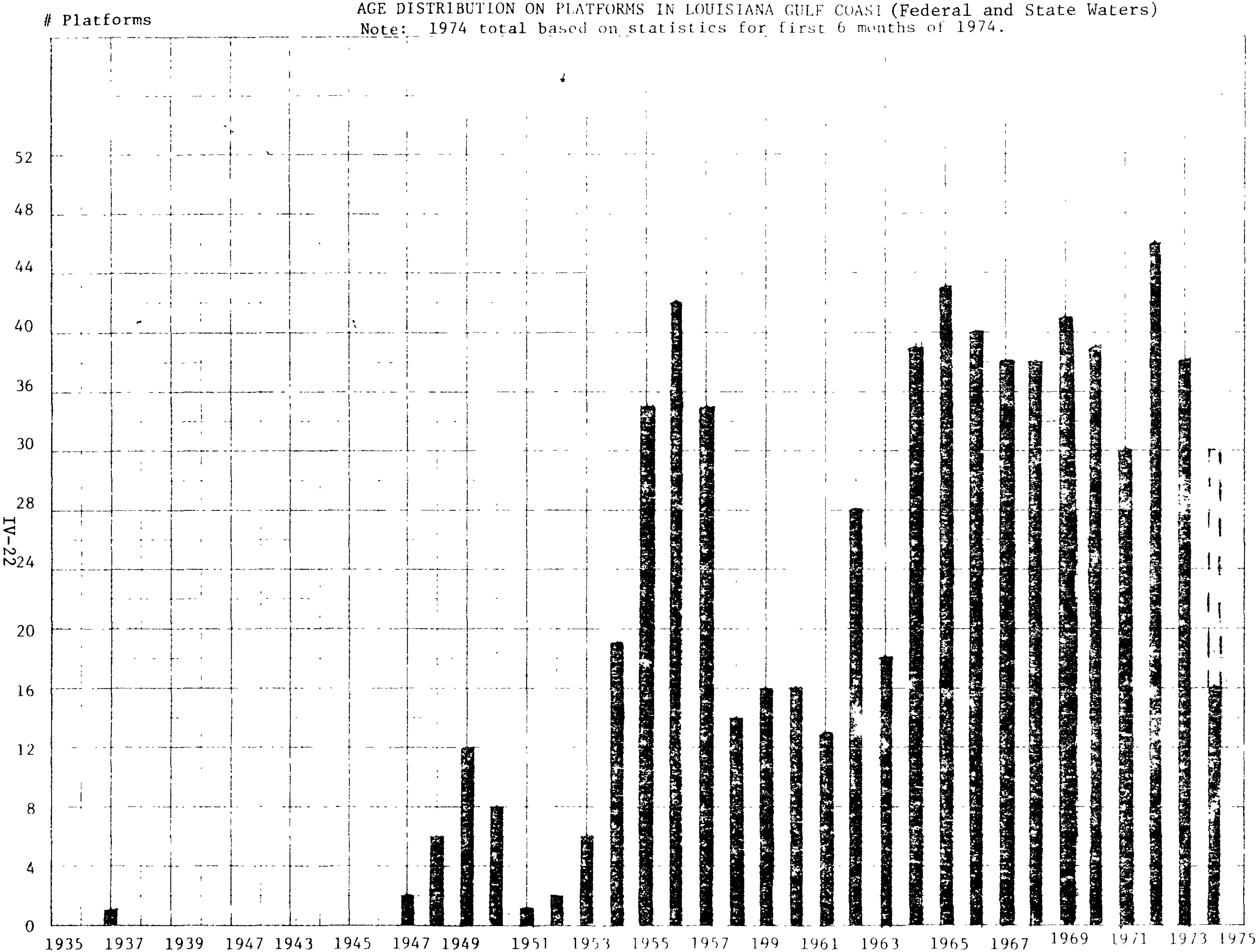


FIGURE IV-5
TOTAL INVESTMENT IN PRODUCTION UNIT AS A FUNCTION OF (1)
- Number of Platforms in Unit
- Total Production Capacity of Unit (1)
3 Platform Unit
Total Investment in Production Unit (in million $)
8
7
6
5
4
3
2
1
SOURCE: BOM Information Circular IC 8557 Offshore Petroleum Studies
TOTAL PRODUCTION CAPACITY (million barrels of oil per day)
10
20
30

AGE DISTRIBUTION ON PLATFORMS IN LOUISIANA GULF COAST (Federal and State Waters)

Note: 1974 total based on statistics for first 6 months of 1974.



Source: ADL

3.3. Investment Costs

Estimates of investment costs, which were required for the calculation of depreciation charges, were again derived from the BOM model. In this case the costs were not updated to allow for inflationary trends between 1969 and 1974 because most (about 75%) of existing platforms in the Louisiana OCS area (See Figure IV-4) are more than five years old and because we want to know what the past actual costs were for depreciation purposes.

Figure IV-5 shows what estimates were used for investment costs for production units which consisted respectively of 1 platform, 2 platforms or 3 platforms. Allowance was made in these estimates for an increase in costs with an increasing maximum capacity of the processing equipment.

In the calculation of depreciation charges corrections were made to allow for the fact that the production units considered in the analysis differed in size from the model production unit and that part of the investment had already been depreciated over the past life of these units.

FIGURE IV-3

Operating Costs (in $/B) Versus

Average Completion Productivity

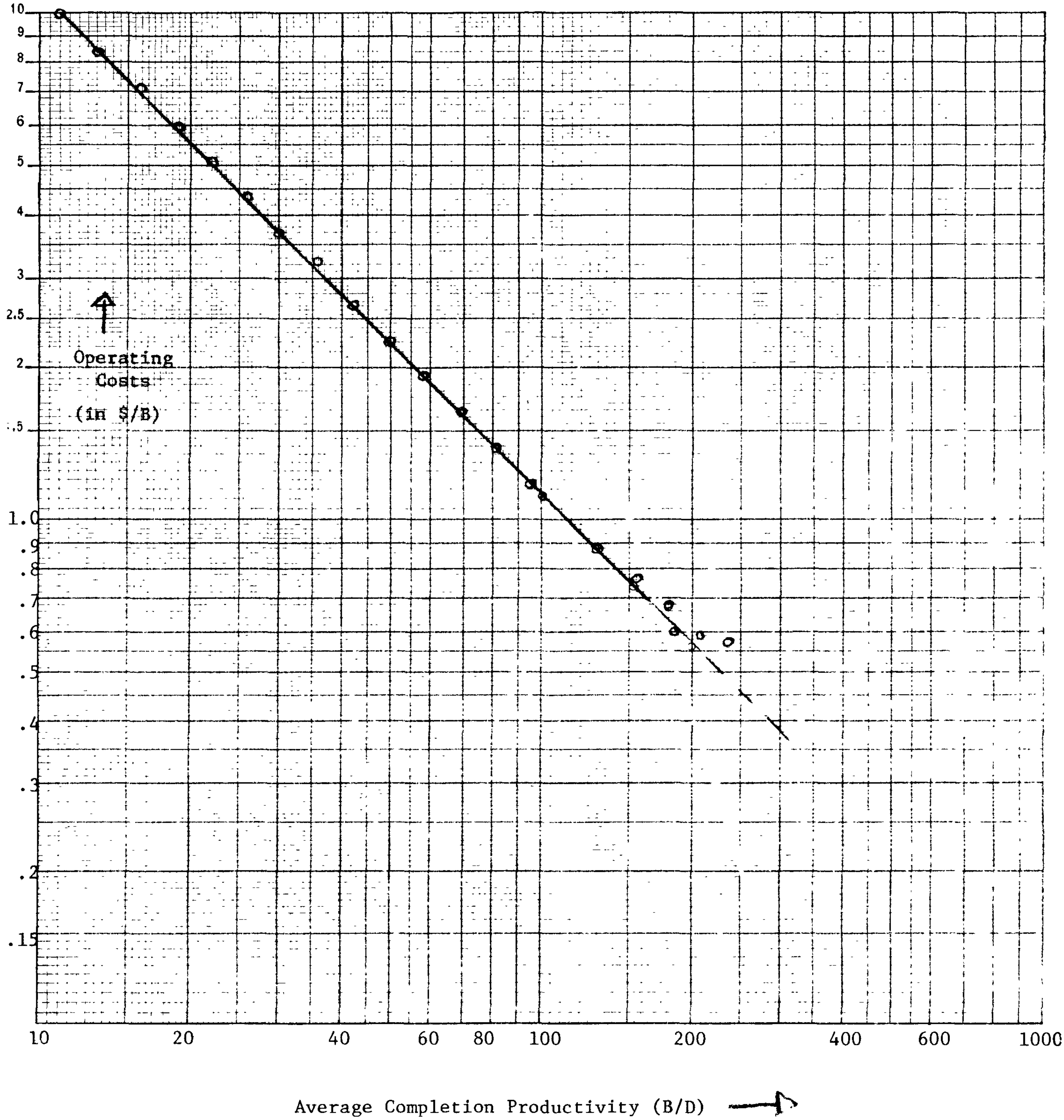


TABLE IV-4

Calculation of Operating Costs in $/B and B/D per Completion

Year	B/Yr thousand bls	$/Yr thousand US$	$/B	B/Comp.(1)
1	499.3	367.6	.74	152
2	1495.8	898.5	.60	186
3	2196.6	1225.2	.56	200
4	2595.2	1470.2	.57	237
5	2745.1	1633.6	.59	209
6	2631.6	1756.1	.67	180
7	2430.3	1837.8	.76	155
8	2117.2	1837.8	.87	129
9	1825.8		1.01	111
10	1563.2		1.17	95
11	1328.7		1.38	81
12	1129.4		1.63	69
13	960.0		1.91	58
14	816.0		2.25	50
15	693.6		2.65	42
16	589.5		3.12	36
17	501.1		3.67	30
18	426.0		4.31	26
19	362.1		5.07	22
20	307.7		5.97	19
21	261.6		7.02	16
22	222.3		8.27	13
23	189.0		9.72	11
24	160.6		11.44	10
25	136.5		13.46	8

(1) Bls/completion

TABLE IV-3

Calculation of Annual Production for the BOM Model Production Unit,[1] Assuming a 15% Annual Decline Rate

No. of Compl.	9	13	8	6	4	3	2	
Initial B/D	152	210	240	182	154	91	102	Total
Year	Annual Production Thousand bls/yr							
1	499.3							499.3
2	499.3	996.4						1495.8
3	499.3	996.4	700.8					2196.6
4	499.3	996.4	700.8	398.6				2595.2
5	424.4	996.4	700.8	398.6	224.8			2745.1
6	360.7	847.0	700.8	398.6	224.8	99.6		2631.6
7	306.6	720.0	595.7	398.6	224.8	99.6	75.0	2430.3
8	260.6	612.0	506.3	338.8	224.8	99.6	75.0	2117.2
9	221.5	520.1	430.4	288.0	191.1	99.6	75.0	1825.8
10	188.3	442.1	365.8	245.0	162.4	84.7	75.0	1563.2
11	160.0	375.8	310.9	208.1	138.1	72.0	63.7	1328.7
12	136.0	319.4	264.3	176.8	117.4	61.2	54.2	1129.4
13	115.6	271.5	224.7	150.3	99.8	52.0	46.1	960.0
14	98.3	230.8	190.9	127.8	84.8	44.2	39.2	816.0
15	83.6	196.2	162.3	108.6	72.1	37.6	33.3	693.6
16	71.0	166.7	138.0	92.3	61.3	31.9	28.3	589.5
17	60.4	141.7	117.3	78.5	52.1	27.1	24.0	501.1
18	51.3	120.5	99.7	66.7	44.3	23.1	20.4	426.0
19	43.6	102.4	84.7	56.7	37.6	19.6	17.4	362.1
20	37.1	87.0	72.0	48.2	32.0	16.7	14.8	307.7
21	31.5	74.0	61.2	40.9	27.2	14.2	12.6	261.6
22	26.8	62.9	52.0	34.8	23.1	12.0	10.7	222.3
23	22.8	53.5	44.2	29.6	19.6	10.2	9.1	189.0
24	19.3	45.4	37.5	25.2	16.7	8.7	7.7	160.6
25	16.4	38.6	32.0	21.4	14.2	7.4	6.6	136.5
26	14.0	32.8	27.2	18.2	12.1	6.3	5.6	116.2

(1) Number of completions and their initial productivity were obtained from the BOM Model production unit discussed in IC 8557/1972.

For these calculations it was assumed that the production profile of each completion had a plateau of level production during the first four years of the completion's life and declined at 15% per year during the remaining life. This differed considerably from the production assumption made in the BOM information ciruclar in 1972 wherein it was assumed that the annual decline rate was close to 6% a year. This difference in decline rate can be explained by the fact that since 1972 allowables have increased to the extent that completions in federal waters in 1975 are produced at their Maximum Efficient Rates.

The annual production resulting from these calculations is shown in Table IV-3. Given the number of producing completions, total annual production and total annual operating costs, the operating cost per barrel produced and average completion productivity was calculated as shown in Table IV-4. The relationship between cost per barrel produced and average completion productivity is shown in Figure IV-3. The functional relationship as shown in Figure IV-3 between operating costs per barrel produced and average completion productivity was used throughout the analysis.

Levels of operating costs per completion for gas producing units were assumed to be the same. Operating costs per completion within state waters were estimated to be 10% lower on the average then operating costs within federal waters, reflecting lower transportation costs for personnel and materials.

Total operating costs in a given year for a production unit with the same number of completions as the model unit but with twice the average daily productivity per completion will not be much different from the total operating costs of the model unit. The only item which might be somewhat higher is surface equipment maintenance (See Table IV-2).

If production unit has twice the number of completions, however, operating costs can be expected to be much higher. Insurance and workover expense, which (Table IV-2) together make up 56% of the operating costs, would be twice as high and more labor will be required to operate the larger number of wells.

Therefore in the analysis a linear relationship was used between the number of completions and total operating costs for a production unit implying that with twice the number of completion on a production unit operating costs would be twice as high regardless the average completion productivity. As a result operating costs per unit produced were assumed to be inversely related with completion productivity, implying that a production units' per barrel or MCF production costs would be twice as high, if average completion productivity would be half and that per barrel or MCF production costs would be half as high if completion productivity would be twice that of another production unit.

In order to establish the functional relationship between operating costs per unit produced and completion productivity over time, a production profile was calculated for the BOM model unit.

TABLE IV-2 - Continued

INDIRECT COSTS

11. ADMINISTRATION & GENERAL OVERHEAD

.40 x (Co. Plant Operators + Line 2 and 7)	
.40 x (33,846 + 21,154 + 24,198) .40 x 79,360 =	$ 31,744

FIXED COSTS

12 INSURANCE

283,500 (footage) x $1.41/ft + $221,665 (all risk)	$621,400
TOTAL OPERATING COSTS, ANNUAL (Excluding Depreciation)	$1,837,855

Source: ADL estimates based on information from industry sources.

TABLE IV-2 - Continued

Helicopter--To assure availability and reduce cost, helicopters are contracted on a monthly basis.

Schedule: 6 hrs/wk for crew changes x 52 = 312 hr/yr
4 hrs/day for transportation of special crews x 1.5 days/wk x 52 = 312 hr/yr

Special Crews: Contract personnel, wireline, machinery maintenance, equipment modifications, painting, etc. Also flights for hauling small equipment and parts for repair.

Monthly Avg. $= \frac{312 + 312}{12} = 52$ hr/mo

Base Rental	1/2 x 8,500 \$/mo x 12 =	\$51,000	
	52 hr/mo x \$60 x 12 =	37,440	
Sub-Total Helicopter		\$88,440	
TOTAL TRANSPORTATION			\$257,252

6. SURFACE EQUIPMENT MAINTENANCE

0.05 x \$2,419,800 (Production equipment cost)	\$120,990

7. OPERATING SUPPLIES

0.20 x \$120,990	\$ 24,198

8. WORKOVER EXPENSE $410,000

Over life of field:

15 Major Workovers @ 500,000 =	\$7,500,000
20 Minor Workovers @ 10,000	200,000
\$25,000/yr wireline work x 20 yr	500,000
	\$8,200,000

$\frac{\$8,200,000}{20} = \$410,000$/yr

9. RADIO & TELEPHONE $ 10,335

10. TOTAL DIRECT COSTS $1,184,711

Source: ADL estimates based on information from industry sources.

TABLE IV-2

SAMPLE OPERATING COSTS
3 Platforms, 28 Wells, 45 Completions

Assuming shifts of 7 days on and 7 days off

DIRECT COSTS

1. LABOR

Contract Labor

1 Cook, 6.50 $/hr. x 12 h/d x 365	$28,470	
1 Cook's Helper 6.00 x 12 x 365	26,280	
1 Gang Leaderman 8.00 x 12 x 365	35,040	
2 Roustabouts 6.50 x 12 x 365	56,940	
1 Pumper 8.00 x 12 x 365	35,040	
1 Electrician-Mechanic 12.50 x 12 x 365	54,750	
Sub-Total Contract (Overhead Included)	$236,520	

Company Labor

2 Plant Operators @ $16,000/yr	$32,000	
Vacation Relief 3 wk/man x 6 x $\frac{16,000}{52}$	1,846	
Sub-Total Plant Operators	$33,846	
TOTAL LABOR		$270,366

2. SUPERVISION

1 Foreman @ $20,000/yr	$20,000	
Vacation Relief 3 wk x $\frac{20,000}{52}$	1,154	
TOTAL SUPERVISION		$ 21,154

3. PAYROLL OVERHEAD

$33,846 + $21,154 x .25	$ 13,750

4. FOOD EXPENSE

15 $/d x 9 x 1.15 (15% for special labor crews) x 365	$ 56,666

5. TRANSPORTATION--Labor, Equipment & Supplies
Assumes company has <u>no</u> adjacent or close-by field operations

Boats

1/2 Shore to Field, combination personnel & supply 475 $/d x 365	$86,687
1/2 Standby and Field transportation boat 450 $/d x 365	82,125
Sub-Total Boats	$168,812

Source: ADL estimates based on information from industry sources.

The estimates of these cost elements, expressed in 1974 dollars, are shown in Table IV-2. They differ considerably from BOM estimated costs due to changes in operating procedures and inflation.

Operating Costs Per Unit Produced Per Completion

The estimates of annual operating costs had to be put on a common basis before they could be applied to the production units considered in the analysis.

For analytical purposes, the average daily productivity per producing completion at each stage of the producing life of the production unit was chosen because the data base specified productivity by completion and not by well.

Most of the wells have more than one completion and as a result, a total of 45 completions are producing oil and gas in the years of peak production. The processing equipment on the platforms is sized to handle oil and condensate production of 10,000 B/D and a peak gas production of 48 million cubic feet/day.

Processing on the main platform consists of: three-phase separation of natural gas, condensate and water; dehydration of the gas to sales specification; water treatment and disposal; storage and transfer of oil (See Figure IV-2). Note that the treatment technologies, which are considered in this analysis have to be added to this processing equipment.

3.2. Operating Costs

Annual operating costs calculated in the BOM model consisted of the following items:

Direct Costs

- labor costs,
- supervision,
- payroll overhead,
- food expense,
- labor transport costs,
- surface equipment maintenance,
- workover expense,
- radio and telephone costs.

Interest and Fixed Costs

- administration and general overhead,
- insurance.

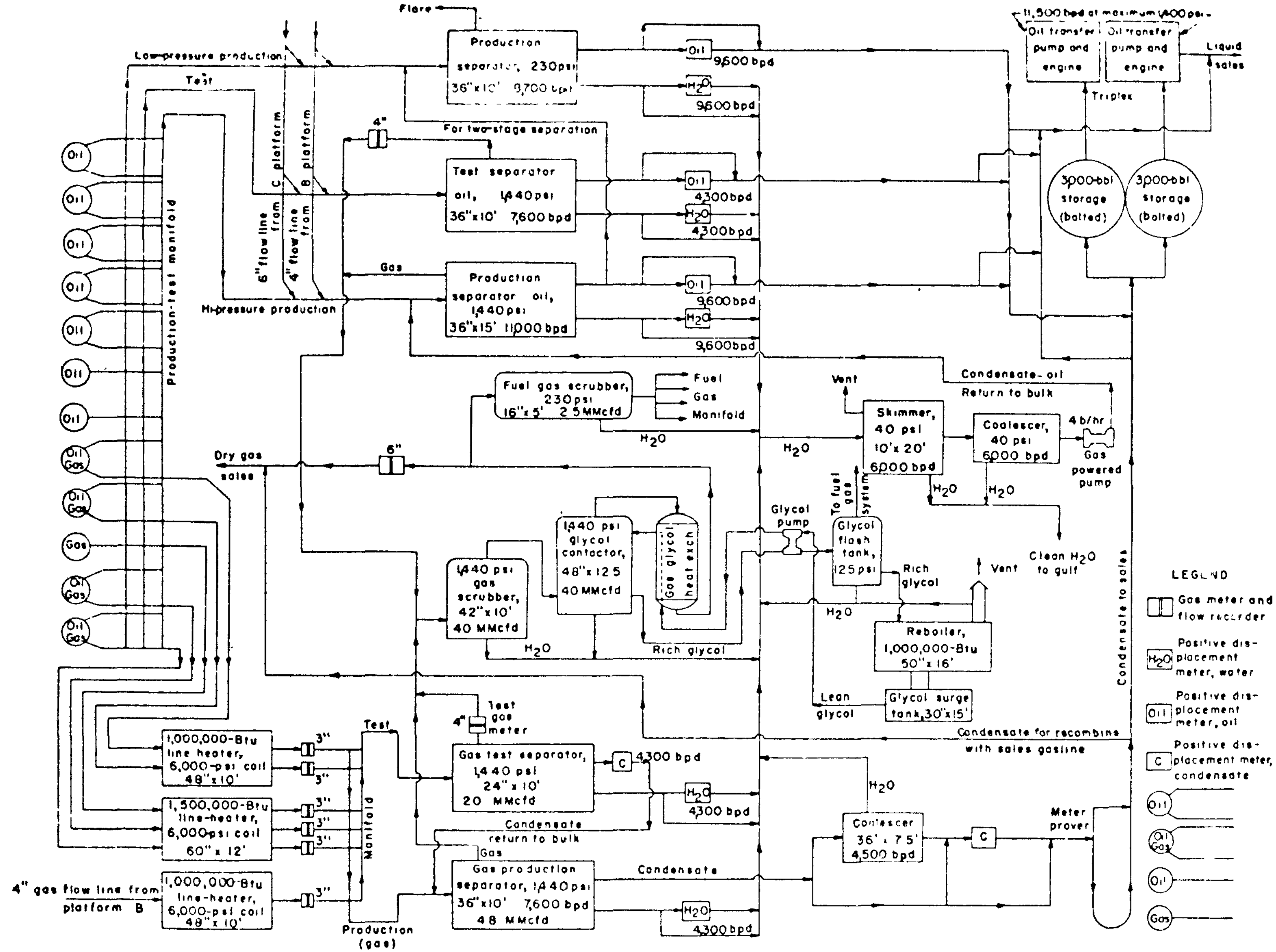
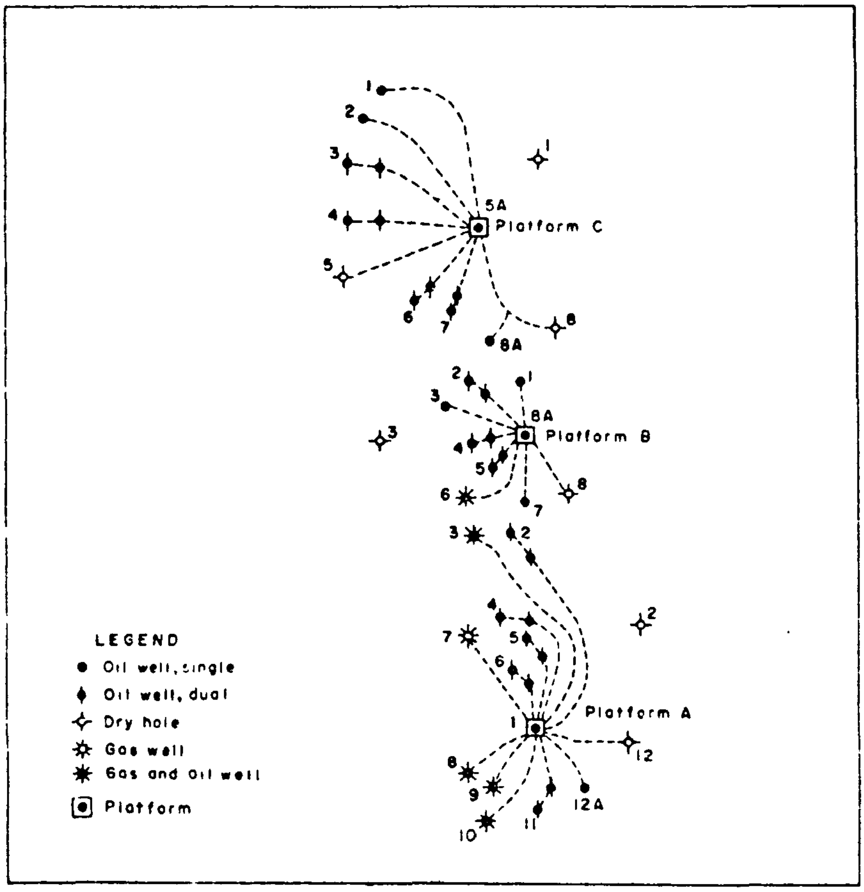


FIGURE IV-2 Scheme of Production Platform A, Model of a Gulf of Mexico Operation.

SOURCE: Bureau of Mines Circular IC 8557/1972



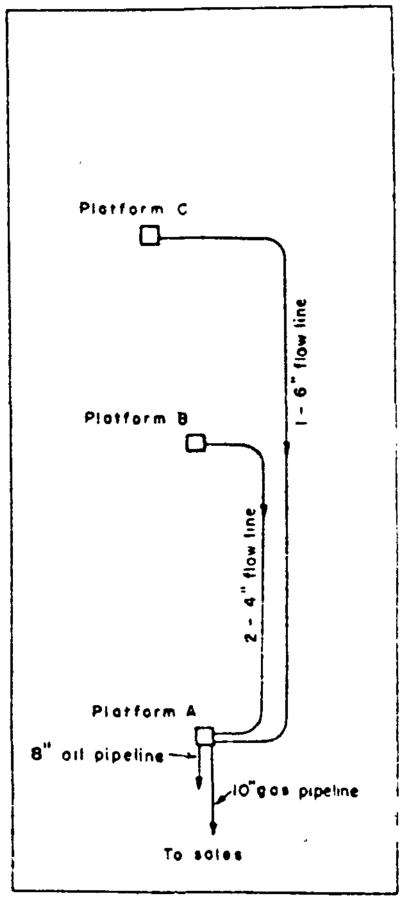


FIGURE IV-1 Lease Plat Showing Platforms, Wells, and Flow Lines in Model.

SOURCE: Bureau of Mines Circular IC 8557/1972

IV.3. PRODUCTION ECONOMICS

The operating costs and investment costs used in the analysis were derived from the estimates made for a model unit described in the Bureau of Mines (BOM) Information Circular IC-8557. This model, as mentioned in the BOM report, was intended to show ". . . the costs involved in exploring, acquiring, developing, producing and abandoning a typical production unit in the Gulf of Mexico." As such it presented a basis for estimating the investment and operating costs of such a typical unit, which then was tested with the industry and adjusted to allow for differences between the BOM model production unit and the actual production units which were considered in this analysis.

3.1. The Bureau of Mines Model Production Unit

The model production unit consisted of three platforms, one main platform with 12 wells, where most of the processing of oil, water and gas is done and two satellite platforms each with 8 wells, where the processing is limited to two-stage separation (See Figure IV-2).

The analysis, using the decision rules described above, represents a simplification of what may happen in reality. In the first place, many individual operators have economic criteria different from the criteria described above. In the second place, the decision to shut down a production unit in a field will also have to consider the effect that the shutdown may have on production from other units in the field, since shutdown of a unit can be expected to change the field's production characteristics.

2.2. Producers Pass On All Costs

It might well be that producers in federal waters will be able to pass on some of the additional costs for treatment and reinjection facilities by increasing their prices for oil and gas. Therefore a likely range of the increase in average cost per Bbl or MCF produced, was calculated assuming the following:

- Producers would like to recover their investment in facilities, including a return on that investment within 15 years.
- The cost increase should reflect the increase in average after tax cost levels over a period of fifteen years, allowing for increases in depreciation charges.

The calculations used projections of aggregated oil and gas production for the period of 15 years following 1977 and 1983 plus estimates of total investment required in treatment and reinjection facilities, thus disregarding differences between individual operators and individual production units.

He will choose that alternative which produces the highest net present value of after-tax cash flow less the net present values of investments required.

If the expected producing life of the production unit falls short of 1983, the operator will simply decide whether to invest in facilities, which are required to comply with the 1977 standards. He can be expected to shut down his production unit in 1977 if he concludes that the investment in the least expensive type of equipment, which will meet the EPA standards, will not be paid for by the present value of after-tax revenues from the unit's expected remaining production.

He will have to shut down in 1983 thereby foregoing some potential production if his analysis shows that the producing life will indeed extend beyond 1983, but that only the less expensive investment in treatment facilities, required for compliance with 1977 standards, will be paid for.

The analysis which is presented on the following pages is based on the assumption that all operators of production units in state waters will appply the above rationale in 1977 when deciding how to comply with the new standards. The analysis then evaluates the loss of potential oil production, which can be expected from:

- Immediate platform shut-downs in 1977 in state and federal waters,
- Platform shut-downs in 1983 in state waters and
- A decrease in the producing life of those platforms in state and federal waters which will not be shut down in 1977 or 1983, but whose ultimate productive lifetime will be foreshortened by increased operating costs.

To determine which alternative he should choose, the operator will first have to establish whether and to what extent the remaining producing life of the production unit will extend beyond 1983.

If the producing life does indeed extend beyond 1983, the operator will then have to compare the net present values of the following cash flows:

- First, the cash flow resulting from an investment in 1977 followed by another investment in 1983 and extending over the producing life, where the producing life has been estimated allowing for additional operating costs, first for the new treatment facilities and later in 1983 for the injection facilities;
- Second, the cash flow resulting from an investment in 1977 in reinjection facilities and extending over the estimated remaining producing life, which will be shorter because of the additional operating costs for the injection facilities.

TABLE IV-1

Possible Alternative Outcomes of an Investment Analysis in New Treatment Facilities in 1977 for a Production Unit in State Waters

	Possible Outcome Of Investment Analysis	Action In Year Of Required Investment 1977	1983
1	Remaining production will not pay for any additional investment.	Shut-in	No investment required
2	Remaining producing life falls short of 1983.	Invest in treatment	No investment required
3	Remaining production will pay out investment in treatment facilities only.	Invest in treatment	Shut-in
4	It is cheaper to invest first in treatment facilities and then in additional injection facilities.	Invest in treatment	Invest in reinjection
5	It is cheaper to invest in reinjection facilities immediately.	Invest in reinjection	No investment required

IV.2. GENERAL APPROACH

2.1. Producers Absorb All Costs

If he has to absorb all additional investment and operating costs in 1977 the operator of a production unit(1) in Federal waters which does not conform to the new standard will have to evaluate the following alternatives:

- He can shut the operations of his production unit, or
- He can invest in treatment facilities required for compliance with the 1977 standards.

The operator's decision to abandon his production unit or to invest in these treatment facilities will likely be based on an estimate as to whether or not production over the unit's remaining life will pay for the investment. The estimate of the remaining producing life of the unit will be based on a comparison of operating costs per unit produced with revenue per unit produced.

The operator of a production unit in state waters in 1977 will be faced with a larger number of possible decisions. He will have to evaluate the following alternatives: (Table IV-1)

- He can shut down the operations of his production unit, or
- He can invest in facilities required for compliance with 1977 standards and delay until 1983 his decision whether to invest in reinjection facilities, or
- He can invest in reinjection facilities immediately.

---

(1) A production unit consists of one or more platforms each accommodating gas and/or oil production from generally 5-20 wells, which is treated to separate the oil, water and gas before oil and/or gas are transported to shore by pipeline.

V. ANALYSIS OF THE DATA BASE

V.1. INTRODUCTION

In the following sections the available data are analyzed to justify certain generalizations which were made for the impact analysis applying the methodology described in the previous chapter.

V.2. GEOGRAPHICAL SEGMENTATION OF OFFSHORE OIL AND GAS PRODUCTION

Offshore oil and gas production is located in three geographical areas: California, Alaska's Cook Inlet and the Gulf of Mexico. (See Table V-1.)

The potential impact on California offshore oil and gas production has not been analyzed in this study since an estimated 95% of the brine produced offshore is thought to be reinjected as required by the 1983 standard. The potential impact for bringing the remaining 5% in compliance is considered to be small.

Cook Inlet crude/condensate production was 11.5% of total U.S. offshore crude and condensate production and 1.7% of total U.S. onshore and offshore production in 1974. Gas production in Cook Inlet was only 1.7% of total offshore and 0.3% of total U.S. production. None of the approximately 13.6 million barrels of water produced annually in Cook Inlet is reinjected at present. At present most of the water from 14 oil producing platforms is piped ashore for processing and discharge into the Inlet.

TABLE V-1

Average Daily U.S. Offshore
Oil and Lease Condensate Production
in 1974 (1)

	Federal		State		Total		% of U.S. Offshore		% or U.S. Total (2)	
	Oil MB/D	Gas MMCF/D	Oil MB/D	Gas MMCF/D	Oil MB/D	Gas MMCF/D	Oil	Gas	Oil	Gas
California	47	15	177	68	224	83	16.8	0.7	2.5	0.1
Alaska	0	0	153	200	153	200	11.5	1.7	1.7	0.3
Louisiana	938	9122	13	1485	951	10607	71.3	91.5	10.7	17.7
Texas	4	439	1	258	5	697	0.4	6.1	0.06	1.2
Total	989	9576	344	2011	1333	11587	100.	100.	14.96	19.3

(1) Source: "Outer Continental Shelf Statistics, 1953-1974", U.S. Department of the Interior, Geological Survey-Conservation Division, June 1975.

(2) Total average daily production in the U.S. in 1974 was 8849 MB/D oil and lease condensate and 60,000 MMCF/D gas.

The Gulf of Mexico is the area of greatest offshore oil and gas production. Offshore Louisiana and Texas produced 72% of the U.S. offshore total oil and condensate and 11% of total U.S. onshore and offshore oil and condensate production in 1974. Total gas production was 92% of U.S. offshore and 18% of total U.S. onshore and offshore production. Gulf waters are further divided into the operations conducted in state waters (out to the three mile limit) and those conducted in Federal waters. Texas state and Federal waters account for 0.7% of total Gulf crude oil and condensate production and 4.2% of gas production with about half of the oil and all of the gas coming from the Federal domain. Louisiana state and Federal waters account for more than 99% of total Gulf crude/condensate production and about 94% of total Gulf gas. Eighty-seven percent of the Louisiana oil and 85% of the gas is from Federal waters.

The division between Gulf state and Federal waters is germane to the impact analysis because E.P.A.'s proposed regulations discern between production from state and Federal waters.

V.3 SOURCE OF DATA AND GENERALIZATIONS USED IN THE ANALYSIS

3.1. Introduction

ADL does not have access to proprietary production and cost data for all production units in offshore areas. Thus it became necessary to make several generalizations before the available data could be used for the analysis.

The data sources available for the purpose of the analysis were the following:

- "Approved Maximum Efficient Rates for Reservoirs and Maximum Production Rates for Well Completions," October 1974; the United States Department of the Interior, Geological Sruvey, Conservation Division, Gulf of Mexico Area O.C.S.
- "Summary Production Report of Oil, Gas, Water by O.C.S. Leases and State Leases with U.S.G.S. Participation in Units from Monthly Report of Operations (9-152) for Producing Leases, June 1974;" United States Department of the Interior, Geological Survey, Conservation Division, Gulf of Mexico Area - O.C.S.
- "Offshore Petroleum Studies. Composition of the Offshore United States Petroleum Industry and Estimation of Costs of Producing Petroleum in the Gulf of Mexico;" Bureau of Mines Information Circular IC-8557, 1972.
- "Draft Development Document for Effluent Limitations, Guidelines and New Source Performance Standards for the Oil and Gas Extraction Point Source Category;" United States Environmental Protection Agency, October 1974.

- A list with multi-well platforms in the OCS area of the Gulf of Mexico obtained from the Offshore Oil Scouts Association, New Orleans, Louisiana.
- "Statistical Report for the Year 1973," State of Alaska Department of Natural Resources, Division of Oil and Gas, Anchorage, Alaska.
- "Production and Proration Order;" State of Louisiana, Department of Conservation, New Orleans, Louisiana, December 20, 1974.
- Personal Communication with EPA and oil industry sources.

Based on this information, estimates were made of:

- The size and number of production units present in offshore areas,
- The annual volumes of oil, gas and water produced from each of these production units and the decline rates of the annual production,

3.2 The Size and Number of Production Units Present in Offshore Areas

Table V-2 shows the numbers of platforms which were considered in the analysis as compared with the actual number of platforms present in 1974 in the federal and state waters of the Gulf of Mexico and in the state waters of Alaska. The sample of platforms used to estimate the possible impact in the federal waters of the Gulf of Mexico was so large (>90%) that it can safely be assumed that the results of the impact analysis based on that sample apply to the total population of platforms in the federal waters.

In leaseblocks with more than one platform, it was necessary to make an assumption of how these platforms were divided over various production units. Some production units consist of more than one platform and in such cases one platform will be the main processing platform where all the oil, water and gas produced by the other platforms will be separated and treated. It is

TABLE V-2

Number of Oil and Gas Platforms Considered and Total Number of Platforms Present in Offshore Areas[1]

		State and Federal Waters	
		Multi Well	Single Well
Louisiana	Actual	644	1858
	Considered	581	1216
Texas	Actual	23	115
	Considered	20	none
Gulf of Mexico	Actual	667	1973
	Considered	601	1216
California	Actual	22	none
	Considered	none	none
Alaska	Actual	14	none
	Considered	14	none

[1] Based on 1973 data for Alaska and 1974 data for California and the Gulf of Mexico.

assumed that for such multi-platform production units the additional water treatment facilities required in 1977 will be located on these main processing platforms as well.

The number of applications for discharge permits filed by offshore operators with the EPA provides an indication of the actual number of treatment facilities in the Gulf of Mexico federal waters. By October, 1974 there had been 327 applications for the Louisiana O.C.S. area, Based

on the distribution shown in Table V-3 and since there is no reason to assume that operators in different lease blocks will or even can combine platforms for water treatment or reinjection purposes, it was assumed that typical production units consist of one platform. The effect of assuming that a production unit consisted of three platforms was also evaluated.

TABLE V-3

Gulf of Mexico, Federal Waters[1];

Distribution of Multi-Well Oil and Gas Producing Platforms[2]

Over Leaseblocks

Number of Platforms per Leaseblock	Type of Platform: Oil — Number of Platforms in Each Category:	Type of Platform: Gas — Number of Platforms in Each Category:
1	111	112
2	44	18
3	25	3
4	14	1
5	7	none
6	6	none
7	2	none
8	2	none
9	1	none
Total Platforms	440	601

(1) Including Louisiana and Texas federal waters.

(2) Platforms considered in the analysis - Refer to Table III-3.

3.3 Estimates of the Annual Volumes of Oil, Gas and Water Produced and Estimates of the Annual Production Decline Rates

For the Gulf of Mexico area information was available on total volumes of oil, gas, condensate and water produced in each leaseblock[1] for the month of June 1974. Tables V-4 and V-5 were developed from this information to obtain an idea of the distribution of different water/oil and water/gas ratios for existing platforms in the Gulf of Mexico federal waters. The tables show how the number of platforms with daily oil or gas production in a given range are distributed over various ranges of water produced with that oil or gas. The ranges for gas and oil production respectively have been chosen to be the same on a thermal equivalence basis,[2] so as to allow comparison of the distribution of water oil ratios for oil producing platforms with the water gas ratios of gas producing platforms.

Figure V-1, which shows the cumulative distributions of oil, gas, and water production from oil and gas producing platforms, suggests the following conclusions:

- Total gas production per platform is consistently higher than total oil production per platform, if measured on a Btu equivalent basis. Of the total of 199 gas producing platforms in a sample, 99 or 49.8% had a production of more than 12,000 MCF/D (= 2000 B/d).

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(1) Source: USGS, Summary Report of Oil, Gas, Water by OCS Leases and State Leases for Producing Leases, June 1974.

(2) 1 Bbl crude oil ≈ 5850 cu. ft. natural gas in terms of Btu equivalents.

TABLE V-4

Louisiana Federal Waters
Number of Oil Producing Platforms Ranked by Total Average Daily Oil and Total Daily Water Production(1)

Average Daily Oil Production per Platform (B/D)	Average Daily Water Production per Platform (B/D) 0-20	20-50	50-100	100-200	200-500	500-1,000	1,000-2,000	2,000-5,000	5,000-10,000	10,000-15,000	Total	Cum. % of Total
0- 20	2		1	1							4	0.9
20- 50				1	1						2	1.4
50- 100	7	1		2	2						12	4.1
100- 200	9	3	2	1	1	2	2				20	8.6
200- 500	16	7	1	7	11	4	2	1			49	19.7
500- 1,000	9	5	4	15	18	6		1	1		59	33.1
1,000- 2,000	10	13	5	39	26	31	16	5	2		147	66.6
2,000- 5,000	10	6	1	13	9	23	16	23	5		106	90.7
5,000-10,000	3		4			2	12	9		4	34	98.4
10,000-15,000	1							1			2	98.9
15,000-20,000				5							5	
TOTAL	67	35	18	84	68	68	48	40	8	4	440	
% of Total	15.2	7.9	4.1	19.1	15.5	15.5	10.9	9.1	1.8	0.9		100%
Cumulative		23.1	27.2	46.3	61.8	77.3	88.2	97.3	99.1			

(1) Sources: U.S.G.S. Conservation Division, Gulf of Mexico Area, O.C.S.:

1. Approved Maximum Production Rates for Well Completions, October 1, 1974
2. Summary Production Report of Oil, Gas, Water by O.C.S. Leases, June 1974

Oil Scouts Association:

Platforms in O.C.S. Leases, June 1974

TABLE V-5

Louisiana Federal Waters
Number of Gas Producing Platforms Ranked by
Total Average Daily Gas and Daily Water Production (1)

Average Daily Gas Production per Platform (MCF/day)	Average Daily Water Production per Platform (B/D) 0-20	20-50	50-100	100-200	200-500	500-1000	1000-2000	2000-5000	Total	Cum. % of Total
0-120	3	1							4	2
120-300	4								4	4
300-600	1		1	2	1				5	6.5
600-1200	1	1							2	7.5
1200-3000	17	1	2		2				22	18.5
3000-6000	24	4	1	1	1				31	34.1
6000-12,000	20	3	3	1	3	1	1		32	50.2
12,000-30,000	24	4	4	3	10	3		1	49	74.9
30,000-60,000	9	5	3	3	4	1	1	1	27	38.5
60,000-90,000	5		1	2	1	2	2		13	95.
90,000-120,000	1								1	95.5
120,000-180,000	2	1			1	1			5	98.
180,000-240,000	1						1	1	3	99.5
> 240,000							1		1	
TOTAL	112	20	15	12	23	8	6	3	199	
% of Total	56.4	10.1	7.5	6.0	11.5	4.0	3.0	1.5		100%
Cumulative		66.5	74	80	91.5	95.5	98			

(1) Sources: U.S.G.S. Conservation Division, Gulf of Mexico Area, O.C.S.:

1. Approved Maximum Production Rates for Well Completions, October 1, 1974
2. Summary Production Report of Oil, Gas, Water by O.C.S. Leases, June 1974

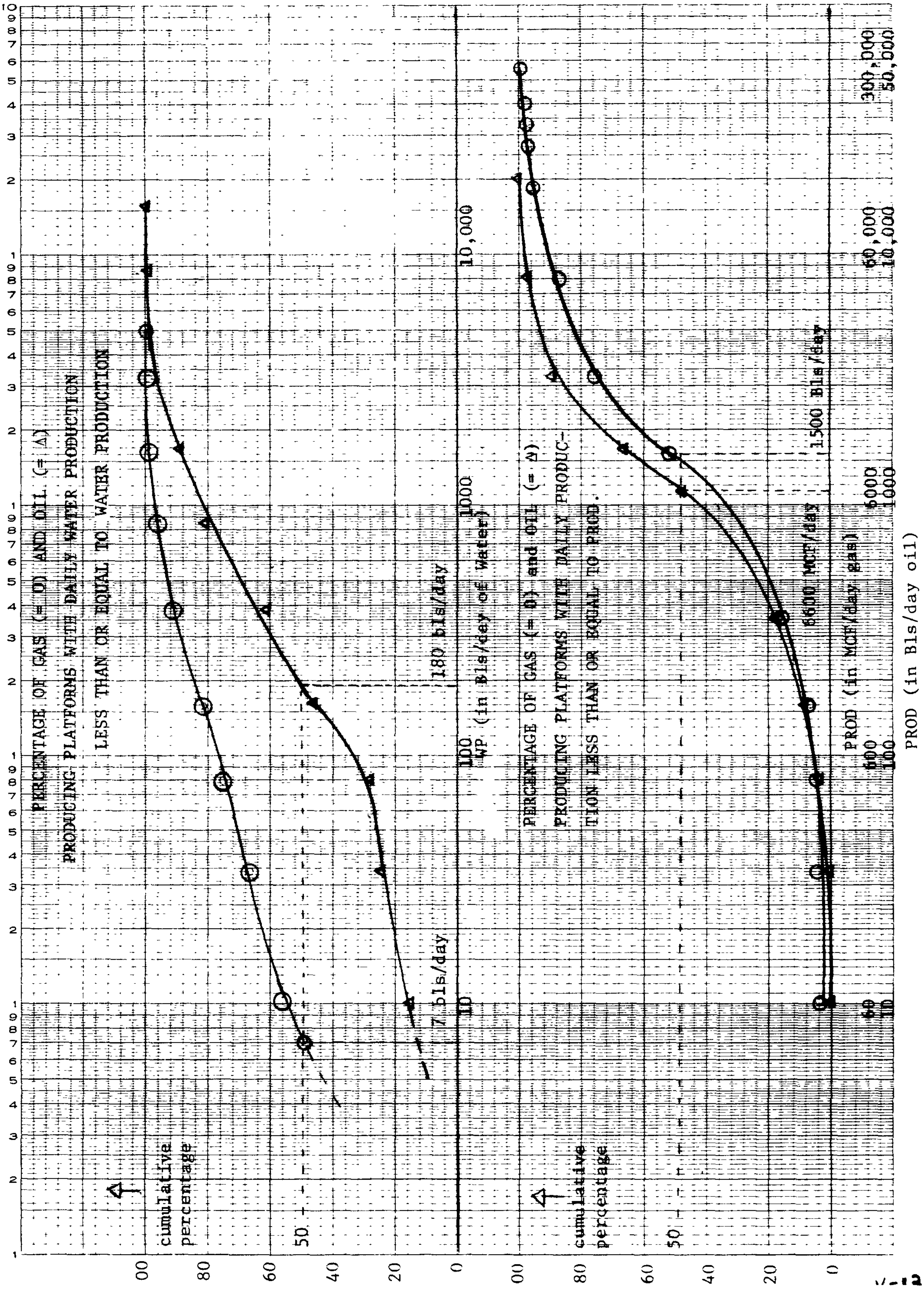
Oil Scouts Association:

Platforms in O.C.S. Leases, June 1974

- Of a total of 440 oil producing platforms, only 147 or 33.4% had a hydrocarbon production of more than 2000 B/D. About 4.5% of the gas producing platforms had a production larger than 120,000 MCF/D equivalent to 20,000 B/D which was the upper limit for the size of oil producing platforms in the sample.
- Total water production on gas producing platforms is significantly smaller than total water production on oil producing platforms. About 75% of the gas producing platforms in the sample had less than 100 B/D of water production, compared, on the same basis, with not more than 28% of the oil producing platforms. Not more than 4.5% of gas producing platforms have water production higher than 1000 B/D compared with approximately 22.5% of the oil producing platforms.
- Maximum water/oil or water/gas ratios are significantly higher for oil producing platforms than for gas producing platforms.

  Not more than 12 (6%) of a total of 199 gas producing platforms have water/gas ratios greater than or equal to one when measured on a barrel equivalent basis (6000 cu. ft. gas + 1 bbl equivalent oil) compared with 97 (22%) of the oil producing platforms.

FIGURE III-1


PERCENTAGE OF GAS (= O) AND OIL (= Δ)
PRODUCING PLATFORMS WITH DAILY WATER PRODUCTION
LESS THAN OR EQUAL TO WATER PRODUCTION
cumulative percentage
50
7 bls/day
180 bls/day
10
100
1000
10,000
WP (in Bls/day of water)
PERCENTAGE OF GAS (= O) and OIL (= Δ)
PRODUCING PLATFORMS WITH DAILY PRODUC-
TION LESS THAN OR EQUAL TO PROD.
cumulative percentage
50
6600 MCF/day
1,500 Bls/day
PROD (in MCF/day gas)
PROD (in Bls/day oil)
60
10
600
100
6000
1000
60,000
10,000
300,000
50,000
00
80
60
40
20
0

For the analyses it was necessary to estimate what size treatment and reinjection capacities would be required on different sized production units. This required an estimate of the amount of water which could be expected to be produced together with the oil and gas of a given field. For this purpose it was assumed that reservoirs included in the data base for the Gulf of Mexico area are without exception water drive reservoirs.(1) The formation pressure in a field with a water drive stays approximately level during the life of the field (except where permeability is low and producing rates high) while the formation pressure of other types of drive mechanisms (e.g. solution gas drive, gas cap drive), decrease with relative uniformity over the life of a field.

Given the fact that the reservoir pressure has to overcome the pressure differentials resulting from the weight of the fluid column in the production tubing plus the resistance to flow in the reservoir, production tubing and surface lines, the amount of formation water produced during any time interval on the field's life can be assumed never to exceed the amount of oil, corrected for the difference in gravity between oil and water. Therefore, for the analysis it was assumed that for a given production unit the capacity of treatment and reinjection facilities would be sufficient to accommodate volumes of water equal to the total volume of oil and water processed in 1974, corrected for the difference in gravity between oil and water.

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(1) Most fields in the Gulf of Mexico have a combination of gas cap and water drive. As a result end of life water production for production units can be expected to be lower than implied by the assumption of a uniform water drive.

In the case of gas fields, based on the statistics shown in Table III-6, it was assumed that the water/gas ratio of barrels of water per MCF of gas produced would never exceed 0.16 and that the maximum capacity for a given water treatment facility on a platform would not exceed 5000 bbls/day of water.

In the absence of information on actual decline curves experienced on production units in the Gulf of Mexico or Alaska offshore a uniform exponential decline rate was assumed, implying that the annual oil or gas production would decrease by the same percentage in each consecutive period. The results of the impact were tested to changes in the value of these decline rates, which were assumed to be 15% per year for oil producing facilities and 12% per year for gas producing facilities.

The approximate volume of annual production in 1974 for each completion for oil wells and gas wells was obtained from the allowable schedules for the Gulf of Mexico federal and state waters. For various reasons, such as well shut-ins for workover purposes or for observation, the allowed production can be less than the actual production during a given year.

Actual oil production and gas production for the Gulf of Mexico area during 1974 and 1973, respectively, was therefore compared with the implied production used in the analysis. Table V-6 shows that the use of allowables in the case of oil resulted in a production estimate about 25% higher than the actual production in 1974. In the case of gas the use of allowables resulted in an estimated production not more than 0.5% different from the actual production. A possible explanation for the much larger difference between actual and implied production for oil in 1974 may lie in the fact that implied production in federal waters was based on the use of Maximum Efficient Rates

TABLE V-6

Actual Production in 1973/1974 Compared with the Production in 1973/1974 Implied by the Use of Allowables in the Analysis

	1974 Production[1]				1973 Production[2]			
	Actual	Implied			Actual	Implied		
	Oil and Lease Condensate	Oil	Condensate	Total	Gas and Oil Well Gas	Gas Well Gas	Oil Well Gas	Total
	(in thousand B/D)				(in thousand MCF/D)			
Federal waters[3]	874	957	32	989	-	7336	1055	8391
State waters[4]	216	253	27	280	-	2732	265	2998
Gulf of Mexico[5]	1090			1269	11422			11389

(1) Source: "Annual Statistical Review, Petroleum Industry Statistics 1965-1974," American Petroleum Inst., May 1975.

(2) Source: "Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada as of December 31, 1974, American Petroleum Institute, May 1975.

(3) Including Louisiana and Texas federal waters.

(4) Louisiana only.

(5) Excluding Texas state waters.

while 1974 production was still based on Maximum Production Rates.[1]

3.4 Production Units in State Waters

For the Gulf of Mexico state waters, information was available only on the number of producing completions by company for each individual pool or field. A considerable number of these fields produce oil, water and gas into onshore facilities, where these fluids are separated and treated. It was assumed that the additional treatment equipment would be sized to process the water produced from these clusters of completions operated by one company. Most of these clusters were relatively small (Table V-7). The size range for treatment systems assumed to be required in state waters can therefore be expected not to be much different from the actual range of required sizes.

3.5 Production Units in Cook Inlet, Alaska

For Alaska, data was available on oil, gas and water production for each completion on the fourteen oil producing platforms in Cook Inlet. This data is discussed in Section VI.4 where the impact analysis for Alaska is discussed.

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[1] The Maximum Efficient Rate for a completion is defined to be that production rate which can be sustained during at least six months without causing lasting damage in the production characteristics of a reservoir.

The Maximum Production Rate is set for resource conservation purposes and as such usually lower than the Maximum Efficient Rate.

TABLE V-7

Size Distribution of Production Units in

Gulf of Mexico Federal Waters(1) and in

Louisiana State Waters

Number of Completions	Federal Waters Oil	Federal Waters Gas(2)	State Waters Oil	State Waters Gas(2)
0-2	96	40	17	12
2-4	104	42	6	7
4-6	103	28	21	7
6-8	66	13	2	4
8-10	44	14	2	1
10-12	12	7	0	2
12-14	12	5	3	0
14-16	15	2	0	1
16-18	6	4	0	1
18-20	7	2	2	2
20-25	11	6	3	2
25-30	0		0	2
30-35	1		0	2
35-40	0		1	1
40-50	0		3	
50-60	0		1	
60-70	0		0	
70-80	0		1	
80			1	

(1) Including Louisiana and Texas federal waters

(2) Nonassociated gas

Source: Production and Proration Order, Louisiana Dept. of Conservation, and U.S.G.S. Conservation Div.

VI. ECONOMIC IMPACT ANALYSIS

VI.1. SUMMARY

The following chapter presents the results of the impact analysis obtained using the methodology as explained in the previous chapter. The analysis was first done for what will be called "base cases" developed separately for the Louisiana state waters and the Gulf of Mexico federal waters using best estimates for important parameters such as prices for oil and gas, annual production decline rates, the cost of capital and using assumptions of the most likely configuration of production units in terms of number of platforms per unit and space availability for additional treatment and reinjection equipment.

This analysis measured the impact by investment and operating costs for additional water treatment equipment expected to be required on oil and gas production units in state and federal waters in 1977 to comply with new water pollution standards and the impact of costs for additional water reinjection facilities expected to be required in 1983 in state waters. The impact was measured in terms of:

- The loss in potential production if oil and gas producers have to absorb the investment and operating costs for the treatment and reinjection facilities.
- The total investment required for treatment and reinjection facilities in 1977 and 1983 respectively.

- The total number of completions which would be abandoned in 1977 and 1983 because some production units will not be able to pay for the additional investment with the remaining production. Price increases are assumed not to occur.
- The average increase in the costs per unit produced.

The analysis considered, oil and gas production in Louisiana state waters and the Gulf of Mexico federal waters using 1974 data for existing production units.

The results of these analyses are summarized in Tables VI-1 and VI-2. If operators of oil and gas producing units existing in 1974, will have to absorb all of the treatment costs and operating costs required for treatment and reinjection facilities, then it can be expected that for units producing in 1974:

- In the Gulf of Mexico, 14.0 to 27.8 million barrels of potential remaining production of oil and lease condensate will be lost or 0.6 to 1.2% of total potential production in 1977 and 81.4 to 249.4 million MCF nonassociated and associated gas representing 0.3 to 1.0% of total potential remaining production in 1977 from oil and gas producing units existing in 1974.

TABLE VI-1

Producers Absorb All Costs
Range of Likely Impact in the Gulf of Mexico
Federal and State Waters(1)

(1974 dollars)

Federal Waters (No Reinjection Required)			
Loss in Potential Prod., oil (2)		0.5 - 1.0%	8.5 - 17.5 MMB
gas (3)		0.3 - 0.85%	60 - 158 MM MCF
Total Invest. Required,	1977		45 - 125 MM $
	1983		N A
Total Completions Aban.	1977	less than 0.3%	2 - 8
State Waters			
Loss in Potential Prod., oil (2)		1.2 - 2.1%	5.5 - 10.3 MMB
gas (3)		0.4 - 1.5%	21.4 - 91.4 MM MCF
Total Invest. Required,	1977		18.8 - 19.7 MM $
	1983		49.7 - 56.4 MM $
Total Completions Aban.	1977	< 0.2%	1 - 2
	1983	3.5 - 6.2%	42 - 75
Total Federal and State			
Loss in Potential Prod., oil (2)		0.6 - 1.2%	14.0 - 27.8 MMB
gas (3)		0.3 - 1.0%	81.4 - 249.4 MM MCF
Total Investment Req.,	1977		63.8 - 144.7 MM $
	1983		49.7 - 56.4 MM $
Total Completions Aban.	1977	< 0.2%	3 - 10
	1983	0.9 - 1.5%	42 - 75

(1) State waters do not include Texas state waters, which represent less than 1% of total oil production in state waters and less than 0.25% of total oil production in federal waters.

(2) Including lease condensate

(3) Including associated gas

SOURCE: Arthur D. Little, Inc., estimates

- Total investment requirements, in 1974 dollars, will be between \$63.8 to \$144.7 million by 1977 and between \$49.7 to \$56.4 million by 1983.
- The number of completions abandoned in 1977 will be less than 0.2% of total producing completions in 1976 or 1977 and the total number of completions abandoned in state waters in 1983 will be between 0.9% to 1.5% of the completions producing in 1982.

Operators will not necessarily have to absorb all of these costs. Therefore it was calculated what the average increase in costs per barrel or MCF produced might be, which producers would like to pass on. The results of these calculations are shown in Table VI-2:

- For oil produced in federal waters, average cost increases in 1977 will likely be between 9.0 to 31.2¢ per barrel and between 11.6 and 16.3¢ per barrel for oil produced in state waters to allow producers to cover investment and operating costs for treatment facilities over a fifteen year period.

TABLE VI - 2

(1) Range of Average Cost Increases in the Gulf of Mexico Federal and State Waters

(1974 Dollars)

	Oil Wells		Gas Wells	
	1977	1983	1977	1983
	(in ¢/Bbl)		(in ¢/MCF)	
Federal Waters				
Cost Increase	9.0 - 31.2	N/A	.14 - 0.92	N/A
State Waters				
Cost Increase	11.6 - 16.3	77.3 - 107.9	0.41 - 0.57	2.41 - 3.31

(2) Economic Cost per Average Barrel of Oil Recovered

	Oil Wells		Gas Wells	
Federal Waters	1977	1983	1977	1983
Ec. Cost per Bbl Recovered ($/Bbl)	94 2382	N/A	42 4511	N/A
State Waters				
Ec. Cost per Bbl Recovered ($/Bbl)	36 - 1237	371 - 8321	133 - 2984	808 - 17741

SOURCE: Arthur D. Little, Inc., estimates

- For oil produced in state waters average cost increases in 1983 will be about 77.3 to 107.9¢ per barrel, allowing producers to recover investment and operating costs for reinjection facilities over a fifteen-year period.

- For gas produced in federal waters, average cost increases in 1977 will be about 0.14 to 0.92¢ per MCF and in state waters they will be about 0.41 to 0.57¢ per MCF, allowing recovery over a period of 15 years investment and operating costs for treatment facilities installed in 1977.

- For gas produced in state waters, average cost increases in 1983 will likely be 2.41 to 3.31¢ per MCF, allowing recovery of investment and operating costs for reinjection facilities installed in 1983.

As mentioned above, the data base used for the analysis consisted of wells reported to be producing in 1974 and as such represented only a part of the wells which will be affected by the new regulations in 1977 and in 1983.

To give a rough indication of potential impact of the guidelines on new wells in the Gulf of Mexico, USGS[1] estimates of reserves

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(1) "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States," Geological Survey circular 725.

were used and the results of the analysis were extrapolated on a unit of reserves basis.

The same was done with estimates of the category of undiscovered recoverable resources in the Gulf of Mexico and other offshore areas as estimated by the U.S.G.S. to obtain at least an indication of the potential impact on the oil and gas wells and platforms expected to be installed later than 1977. The results show that for new sources the loss in potential production might be as high as .35 billion bbls of oil and 1.75 billion MCF of gas if price increases are not allowed. Investment might be as high as 1.92 billion dollars (see Table VI-17). These high estimates of losses in potential production from recoverable resources are equivalent to about 75% of 1974 offshore oil production and to about 15% of 1974 offshore gas production. The losses will not occur during any single year but rather during a period of about 50 years starting somewhere between 1990 and 2000. The additional investment required will also be made over a period of at least 30 years following 1977, rather than having to be made in any one single year.

Since some oil which otherwise would be discharged will be recovered through the additional treatment required in 1977, this treatment can be considered as another way to produce oil. It is shown in Section VI-10 of this chapter that the treatment technology considered to be BPCTCA[1] on the average recovers more energy than it consumes. However, in terms of economic cost per barrel recovered, it can be considered as, at best, a rather marginal investment if the objective would only be to produce more barrels of oil at an earlier point in time.

- For oil wells the average economic cost[2] per barrel recovered in 1977 for treatment facilities will be somewhere between $36 to $2382 mainly depending on the amount of water treated during that period.

- For gas wells the economic cost per barrel recovered in 1977 will be somewhere between $42 and $4511.

Reinjection systems to be installed in state waters in 1983 are not part of the treatment systems proper. If it is assumed, however, that these systems will have to be paid for by the oil which is recovered through treatment then, as shown in Table VI-2, the economic cost per barrel recovered for oil wells will be between $371 and $8321 and for gas wells between $808 and $17741.

As mentioned earlier, cost data which would allow a rigorous analysis of the potential impact on offshore oil and gas production in Cook Inlet in Alaska were not available. A preliminary estimate of the potential impact has been made assuming that costs for oil and gas production and required treatment and re-injection in Cook Inlet will be from three to six times higher than the ones used in the impact analysis for the Gulf of Mexico. The results of this estimate are discussed in Section VI-12.

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(1) Best Practicable Control Technology Currently Available.

(2) The average cost per barrel recovered over a 15-year period allowing for a return on investment of 12% to 20% and after tax operating costs.

VI.2. FEDERAL WATERS: BASE CASE RESULTS FOR OIL WELLS AND GAS WELLS

The computer program, discussed in the previous chapter, was used to estimate the impact of the new treatment regulations on existing oil and gas producing facilities in the federal waters of the Gulf of Mexico. Base case parameter values and assumptions consisted of the following:

- Oil and gas wellhead prices of $7.50/Bbl and $0.50/MCF respectively.
- Annual decline rates of 15%/yr for oil and 12%/yr for gas.
- Production units consist of one platform.
- All platforms will require additional treatment equipment in 1977, consisting of surge tank and flotation unit.
- All platforms will have enough space to accommodate this additional equipment.

The results of the analysis for oil wells are shown in Table VI-3.

Only one oil producing platform with one producing completion would likely be abandoned in 1977 resulting in a loss of potential production not more than 36.4 MB or less than 0.3% of the total 14.0 MMB of oil production foregone. The annual volumes of potential production lost through immediate abandonment in 1977 are shown in the column under the heading "Production Loss By Platform Shut-ins in 1977." Most of the potential oil production loss, 13.98 MMB or 99.7% of the total of 14.0 MMB, will be by a decrease in the producing lives of completions.

The annual volumes of potential production lost by this decrease in the producing life of completions is shown in the column under the heading "By Decrease in Producing Life." The number of completions abandoned annually shown in the column under the heading "Abandonments."

In addition to the loss of potential oil production of 14.0 MMB, 40.3 MM MCF of associated gas has been estimated to be lost as well. These losses in

TABLE VI-3

Federal Waters - Oil
Producers Absorb All Costs

Year	Production Loss by Platform Shut-ins in 1977 (barrels)	Production Loss by decrease in Producing life (barrels)	Completion Abandonments
1977	10548.	0.	1.
1978	8966.	0.	0.
1979	7621.	0.	0.
1980	6478.	6478.	1.
1981	2753.	2753.	0.
1982	0.	63420.	10.
1983	0.	48586.	6.
1984	0.	14795.	4.
1985	0.	69811.	14.
1986	0.	188372.	39.
1987	0.	633870.	94.
1988	0.	553529.	72.
1989	0.	545784.	100.
1990	0.	828194.	207.
1991	0.	1090137.	263.
1992	0.	1719230.	358.
1993	0.	1571703.	243.
1994	0.	2618419.	509.
1995	0.	1478244.	231.
1996	0.	765539.	150.
1997	0.	601201.	130.
1998	0.	434335.	110.
1999	0.	197868.	47.
2000	0.	194716.	63.
2001	0.	188588.	30.
2002	0.	85308.	1.
2003	0.	26137.	3.
2004	0.	11108.	0.
2005	0.	28270.	4.
2006	0.	12015.	0.
TOTAL	36367.	13978478.	2690.

Total Equipment Investment in 1977: $63.9 million
Fraction of Investment Made in Reinj. in 1977: .0000
Total Equipment Investment in 1983: 0
Platforms Immediately Abandoned: 1
Total Oil Production Foregone: 14.0 million Bbls
Total Associated Gas Foregone: 40.3 million MCF
Completion Lost before 1977: 4.
Production Lost before 1977: .054 million barrels

SOURCE: Arthur D. Little, Inc., estimates

potential production of oil and associated gas will amount to about .88% of estimated recoverable oil reserves in 1977 and 1.12% of associated gas reserves. Total investment required for additional equipment in 1977 will be 63.9 MM $.

Table VI-4 shows the base case results for the gas wells in federal waters. Early abandonments in 1977 will result in a loss of potential gas production of 513.8 M MCF or less than .7% of a total of 75.4 MM MCF of non-associated gas.

About 74.9 MM MCF of non-associated gas, or 99.3% of the total loss in potential production, will be through a decrease in the producing lives of well completions. It is estimated that together with the loss of a total of 75.4 MM MCF of non-associated gas about 1.1 MMB of condensate will be foregone.

Total gas production foregone will be about 0.5% of estimated recoverable reserves in 1977 and total condensate production foregone will be about 0.67% of estimated reserves. Total investment requirements in 1977 will be 23.5 MM$.

Given the small number of early abandonments in 1977 it can be expected that the new regulations will have no effect on the employment situation related with oil and gas production in federal waters.

TABLE VI-4
Federal Waters - Gas
Producers Absorb All Costs

Year	Production Loss by Platform Shut-ins in 1977 (MCF)	Production Loss by Platform Shut-ins in 1983 (MCF)	Production Loss by decrease in Producing Life (MCF)	Completion Abandonments
1977	141328.	0.	0.	1.
1978	124362.	0.	0.	0.
1979	109444.	0.	0.	0.
1980	96311.	0.	0.	0.
1981	42377.	0.	932291.	20.
1982	0.	0.	0.	0.
1983	0.	0.	400363.	4.
1984	0.	0.	285899.	1.
1985	0.	0.	299876.	2.
1986	0.	0.	131945.	0.
1987	0.	0.	110208.	1.
1988	0.	0.	1063357.	15.
1989	0.	0.	481590.	2.
1990	0.	0.	1124577.	16.
1991	0.	0.	2101707.	35.
1992	0.	0.	496517.	3.
1993	0.	0.	2969457.	43.
1994	0.	0.	2585543.	19.
1995	0.	0.	3058941.	22.
1996	0.	0.	5917750.	70.
1997	0.	0.	3024847.	26.
1998	0.	0.	7426749.	90.
1999	0.	0.	10364249.	133.
2000	0.	0.	9699839.	110.
2001	0.	0.	6276906.	67.
2002	0.	0.	4242638.	44.
2003	0.	0.	2484772.	19.
2004	0.	0.	3500441.	38.
2005	0.	0.	4744713.	75.
2006	0.	0.	383344.	0.
TOTAL	513822.	0.	74694568.	856.

Total Equipment Investment in 1977: $23.5 million
Fraction of Investment Made in Reinj. in 1977: .0000
Total Equipment Investment in 1983: 0.
Platforms Immediately Abandoned: 1
Total Gas Production Foregone: 74.0 million MCF
Total Oil Production Foregone: 1.1 million barrels
Completions Lost Before 1977: 10.
Production Lost Before 1977: 1.89 million MCF

SOURCE: Arthur D. Little, Inc., estimates

Federal Waters; Sensitivity Tests by Changes in Base Case Parameters

The base case results were tested for their sensitivity to changes in the following parameters and assumptions:

- Changes in the "wellhead" price for oil, ranging from $5.25 to $11.00/Bbl, and for gas, ranging from $0.30 to $0.75 per MCF.
- Changes in the annual decline rate, ranging from 12% to 18% for oil and from 9% to 15% for gas.
- Changes in the cost of capital, ranging from 12% to 25% for oil - as well as for gas producers.
- Assuming that extra space would be added on to existing platforms either by an extra deck or by an additional platform if extra space requirements exceeded 1000 square feet.
- Assuming that production units consisted of clusters of 3 platforms rather than 1 platform units.

The results of these sensitivity tests produced the following conclusions (see Tables VI-5 and VI-6):

- The estimated impact in terms of percentage loss of total potential production is most sensitive to changes in the price parameter.
  For oil this estimate ranged from a high 1.06% to a low 0.56% of potential production lost, assuming "wellhead" prices of $5.25 and $11.00 per barrel respectively.
  For gas this estimate ranged from a high 0.98% to a low 0.29%, assuming wellhead prices of $0.30 and $0.75 per MCF respectively.
- The estimated impact in terms of total investment required is very sensitive to changes in the assumptions about whether extra space will have to be provided by an extra deck or extra platform and whether typical

TABLE VI-5

Sensitivity of Results to Changes in Key Variables

(1974 dollars)

Federal waters; no reinjection required; oil

Producers Absorb All Costs

Varied Parameter	Value	% Loss of Potential Production		Total Investment (in MM$)			Number of Completions Abandoned		Number of Producing Completions
		Oil	Gas	1977	1983	Total	1977	1983	End 1976
Price	$ 5.25	1.06	1.38	63.70	NA		3	NA	2690
	*$ 7.50	0.88	1.12	63.86			1		2690
	$ 9.00	0.73	0.94	63.86			5		2694
	$11.00	0.56	0.77	63.99			3		2694
Decline Rate	12%	0.66	0.95	64.88			1		2690
	18%	0.94	1.24	62.78			2		2690
Cost of Capital	15%	0.88	1.12	63.86			1		2690
	20%	0.88	1.12	63.86			1		2690
	25%	0.88	1.12	63.86			1		2690
Extra Space Required		0.89	1.13	120.41			3		2690
3 Platform Unit		0.80	1.03	40.87			1		2690

*Base Case: 1 Platform Unit
Equipment Technology C
Price $7.50
Decline Rate 15%/year
Cost of Capital 12%/year

SOURCE: Arthur D. Little, Inc., estimates

TABLE VI-6

Sensitivity of Results to Changes in Key Variables

(1974 dollars)

Federal waters; no reinjection required; gas

Producers Absorb All Costs

Varied Parameter	Value	% Loss of Potential Production		Total Investment (in MM$)			Number of Completions Abandoned		Number of Producing Completions
		Gas	Oil	1977	1983	Total	1977	1983	End 1976
Price	$ 0.30	0.98	1.10	23.31	NA		1		971
	*$ 0.50	0.50	0.67	23.50			1		971
	$ 0.75	0.29	0.32	23.61			3		971
	$ 1.00	NA							
Decline Rate	9%	0.17	0.41	23.74			0		971
	15%	0.65	0.75	23.30			1		971
Cost of Capital	15%	0.51	0.67	23.51			1		971
	20%	0.51	0.67	23.51			1		971
	25%	0.51	0.67	23.51			1		971
Extra Space Required		0.50	0.67	35.60			1		971
3 Platform Unit		0.50	0.67	5.5			0		971

*Base Case: 1 Platform Unit

Equipment Technology C

Price	$0.50
Decline Rate	12%/year
Cost of Capital	12%/year

SOURCE: Arthur D. Little, Inc., estimates

production units consist of clusters of more than one platform.

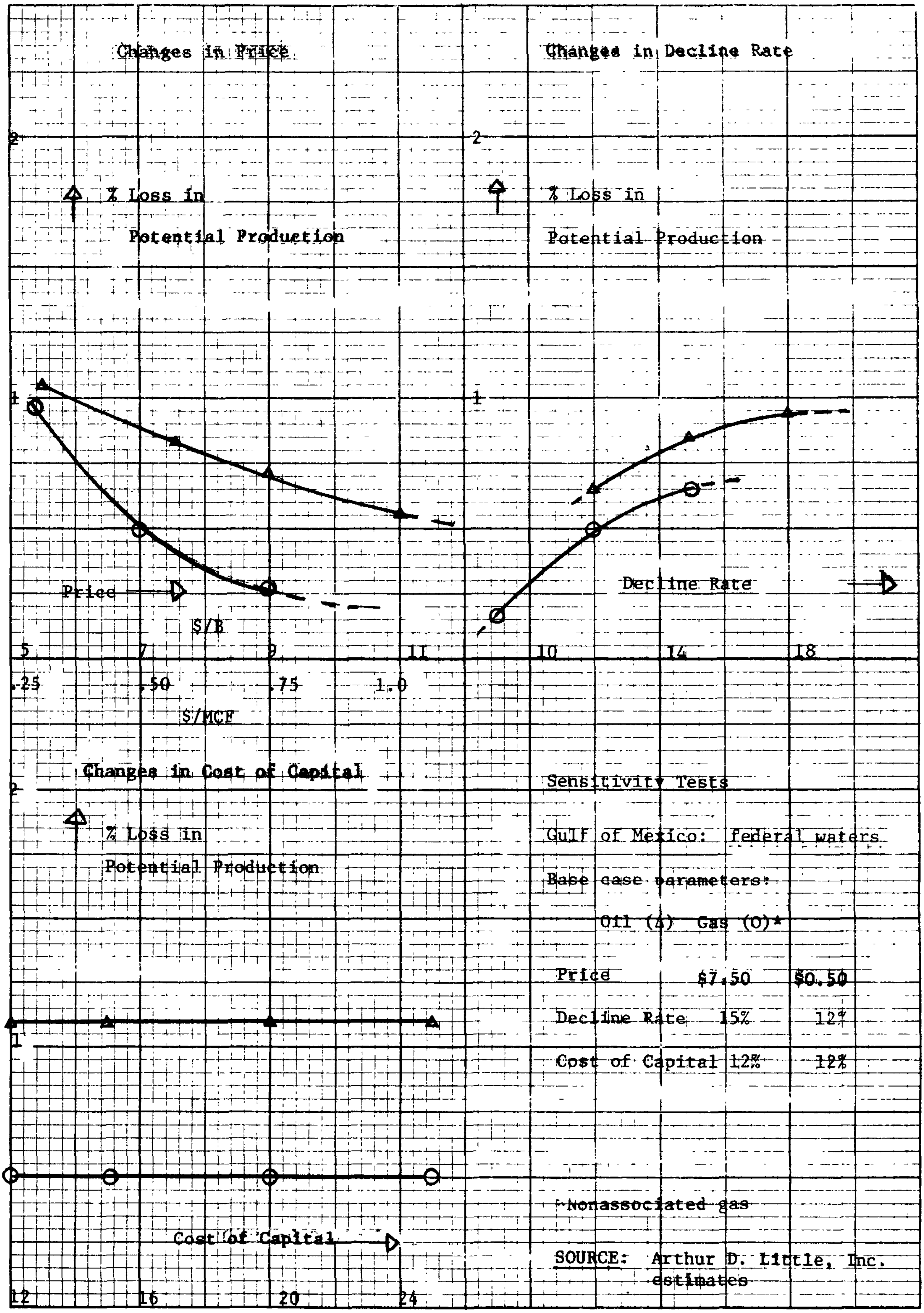
If production units were assumed to consist of one platform which will require an extra deck or an extra platform, when total space requirements for the treatment facilities exceed 1000 square feet, then investment costs for oil producing facilities will almost double to $120 million and investment costs for gas producing facilities will increase by about 50% to $35 million.

On the other hand, if we assume that typical production units consist of three platforms rather than one, then total investment requirements for oil producing units will be 50% of the base case value or $40 million and total investment requirements for gas producing units will be 25% of the base case value or $5.5 million.

- The number of early abandonments in 1977 remains very small despite changes in parameters; less than 0.2% of the total number of producing completions in 1977 for oil producing units and less than 0.3% for gas producing units.

- The results of the impact analysis are not very sensitive to changes in the cost of capital. No significant change in the results occurred even when the cost of capital was 25%.

FIGURE VI-1



Changes in Price
2
% Loss in
Potential Production
1
Price
$/B
5
7
9
11
.25
.50
.75
1.0
$/MCF
Changes in Decline Rate
2
% Loss in
Potential Production
1
Decline Rate
10
14
18
Changes in Cost of Capital
2
% Loss in
Potential Production
1
Cost of Capital
12
16
20
24
Sensitivity Tests
Gulf of Mexico: federal waters
Base case parameters:
Oil (Δ) Gas (O)*
Price $7.50 $0.50
Decline Rate 15% 12%
Cost of Capital 12% 12%
*Nonassociated gas
SOURCE: Arthur D. Little, Inc. estimates

The results of these sensitivity tests are also shown in Figure VI-1. It is shown in this figure that the percentage loss in potential production of nonassociated gas is consistently lower than the loss in potential oil production. Also, it does appear that the percentage loss of potential gas production will not become much less than 0.20% when the wellhead price is increased and not much more than 0.75% when the decline rate is increased. The fact that present-day intrastate prices are already higher than $1 per MCF indicates that it can reasonably be expected that not much gas will be sold in 1977 at $0.35 per MCF. The range in which the actual percentage loss in potential production probably will be is therefore 0.20% to 0.75%.

Using the same reasoning, but choosing $5.25 as the lower limit for the expected price in 1974, the probable range for the percentage loss in oil production was taken to be between 0.50% and 1.00%.

Summarizing for the federal waters, the results of the impact analysis amount to the following (See Table VI-7):

- Loss in potential gas production from both gas and oil wells will be between 8.5 and 17.5 million barrels. (no price increases)
- Loss in potential gas production from both gas and oil wells will be between 60-158 million MCF. (no price increases)
- Total investment required in 1977 in terms of 1974 dollars, will amount to between 45 and 125 million dollars.
- Between 2-8 completions will have to be abandoned in 1977.

TABLE VI-7

Range of Likely Impact in the Gulf of Mexico Federal Waters[1]

(1974 dollars)

Oil Wells				
Loss in Potential Prod.,	oil	0.5 - 1.0%	or	8 - 16 MMB
	ass. gas			22 - 44 MM MCF
Completions Abandoned in	1977	less than 0.2%		1 - 5
Investment Required in	1977			40 - 100 MM $
Gas Wells				
Loss in Potential Prod.,	gas	0.2 - 0.75%	or	38 - 114 MM MCF
	condensate			0.5 - 1.5 MMB
Completions Abandoned in	1977	less than 0.3%		1 - 3
Investment Required in	1977			5 - 25 MM $
Total Loss in Potential Prod.	oil			8.5 - 17.5 MMB
	gas			60 - 158 MM MCF
Total Investment Req. in	1977			45 - 125 MM $
Total Completions Aban. in	1977			2 - 8
	1983			

(1) Assuming producers absorb all costs.

SOURCE: Arthur D. Little, Inc., estimates

Average Cost Increases for Oil and Gas, Federal Waters

It might well be that producers in federal waters can pass on some of the additional costs for treatment facilities by increasing the price for oil and gas in 1977. Therefore, the range was calculated of these average cost increases separately for oil and gas produced in the Gulf of Mexico Federal waters.

First, assuming that producers would like to have a return on their investment within 15 years, cumulative production of oil and gas was calculated for the 15-year period starting in 1977. (See Table VI-8.)

Second, using the low and high estimate of the likely investment requirement for oil producing facilities and the corresponding annual operating cost estimates, the average per-barrel capital charge (Item 5), the per-barrel operating cost (Item 7), and per-barrel depreciation charge (Item 8) could be calculated.

Third, the net after tax increase in per-barrel operating costs was calculated using a tax rate of 0.5 (Item 9).

The estimated average cost increase was then found by adding the after tax capital charge and the increase in after-tax operating costs.

The capital charge was calculated assuming a 12% and 20% capital cost to indicate how sensitive the cost estimate was to this particular parameter.

The results show that a price increase for oil in 1977 would have to be between 3.7 and 9.6¢ per barrel and between 0.06 and 0.30¢ per MCF for gas if producers are to recover the treatment facilities operating and investment costs including a return on that investment.

TABLE VI -8

Range for Likely Average Cost Increases in 1977

for Producers in

Federal Waters, Gulf of Mexico

(1974 dollars)

		Oil Wells 1977	Gas Wells 1977
1.	Production in 1977[1]	252.6	1850.6
2.	Production in 1991[1]	23.8	305.8
3.	Cum. Production (15 years)[1]	1296.5	11328.5
4.	Investment (MM $)	40 - 100	5 - 25
5.	Cap. Charge per Bbl (MCF) (4 x 2.80)/ 3	8.8 -21.5 ¢/B	0.13 - 0.63 ¢/MCF
6.	Add Ann. Op. Costs (MM $)	3.4 - 8.6	
7.	Add Op. Costs per Bbl (MCF) (6 x 15)/ 3	3.9 - 9.9 ¢/B	0.06 - 0.28 ¢/MCF
8.	Add Dep. Charge per Bbl (MCF) (4/1) (¢/B)	3.1 - 7.7 ¢/B	0.04 - 0.22 ¢/MCF
9.	Add After Tax per Bbl (MCF) Op. Cost 0.5 x (7-8)	0.2 - 0.5 ¢/B	0.01 - 0.03 ¢/MCF
10.	Cost Increase (5 + 9) (assuming 12% Capital Cost)	9.0 -22.0 ¢/B	0.14 - 0.66 ¢/MCF
11.	Cost Increase (assuming 20% Capital Cost)	12.7 -31.2 ¢/B	0.19 - 0.92 ¢/MCF

[1] In MMB or MM MCF

SOURCE: Arthur D. Little, Inc., estimates

VI.3. STATE WATERS: BASE CASE RESULTS FOR OIL WELLS AND GAS WELLS

The impact of treatment requirements in 1977 and reinjection requirements in 1983 in state waters was estimated for offshore Louisiana using the computer program described in the previous chapter. The base case parameters used were the same as for the impact analysis for federal waters.

In the previous chapter it was explained that no data were available on platforms in Louisiana state waters. Therefore, it was assumed that production units consisted of clusters of completions reported to be operated by one company in the fields, which were considered. Also it was assumed that, if treatment of produced oil, gas and water took place on a platform, adequate space would be available to accommodate additional treatment equipment. If treatment would have to be done on land, then space availability would not be a limiting factor.

Table V-7 indicates that this assumption may have introduced some bias towards large treatment facilities, if production units within state waters are distributed similarly as in federal waters.

Data on water, associated gas and condensate production were not available on a lease-by-lease basis as for federal waters. Therefore, averages had to be used obtained by using gross production data for the area.

Based on these gross production data, an oil/water ratio of .70, a gas/oil ratio of .95 MCF associated gas per Bbl of oil, and a condensate/ gas ratio or .011 Bbl of condensate per MCF of nonassociated gas was used in the analysis.

Table VI-9 and VI-10 shows the results for oil and gas wells in the state waters respectively. For oil, these results show that:

- With no price increases, total loss in potential production will amount to 6.87 million barrels of oil and 6.53 million MCF of associated gas; less than 0.35% of this total will be due to early abandonments in 1977, about 7% due to early abandonments in 1983, and the rest or 92.65% will be due to a shortening of the producing life of completions.
- Total equipment investment will be $13.5 million in 1977 and $37.7 million in 1983 or a total of $51.2 million.
- Early abandonments in 1977 will be 2 completions or less than 0.3% of total producing completions in 1977 and 53 in 1983 or about 6.5% of the 1977 total.
- All operators will prefer to wait until 1983 before investing in reinjection facilities rather than to invest in reinjection facilities in 1977.

Table VI-10 shows the results of gas wells from which it can be concluded that:

- A total of 60.4 million MCF of gas and 0.68 million barrels of condensate will be lost, of which 3.1 million MCF or 5.1% will be lost due to early abandonments in 1983 and 57.3 million MCF or 94.9% due to a decrease in producing lives of completions if no price increases are possible.

TABLE VI-9

State Waters - Oil

Producers Absorb All Costs

Year	Production Loss by Platform Shut-ins in 1977 (barrels)	Production Loss by Platform Shut-ins in 1983 (barrels)	Production Loss by decrease in producing life (barrels)	Completion Abandonments
1977	12922.	0.	0.	2.
1978	8294.	0.	0.	0.
1979	2382.	0.	0.	0.
1980	0.	0.	0.	0.
1981	0.	0.	0.	0.
1982	0.	0.	0.	0.
1983	0.	134806.	151180.	53.
1984	0.	114536.	4476[illegible].	0.
1985	0.	72290.	115118.	40.
1986	0.	40069.	114[illegible]2.	0.
1987	0.	34058.	37537.	4.
1988	0.	28950.	334509.	53.
1989	0.	22244.	244102.	14.
1990	0.	12148.	149697.	15.
1991	0.	6288.	1021542.	160.
1992	0.	2672.	1012427.	101.
1993	0.	0.	711207.	118.
1994	0.	0.	359340.	60.
1995	0.	0.	592366.	76.
1996	0.	0.	352096.	14.
1997	0.	0.	109634.	0.
1998	0.	0.	119436.	10.
1999	0.	0.	357933.	46.
2000	0.	0.	325686.	22.
2001	0.	0.	148464.	0.
2002	0.	0.	126194.	0.
2003	0.	0.	53633.	0.
2004	0.	0.	0.	0.
2005	0.	0.	0.	0.
2006	0.	0.	0.	0.
TOTAL	23597.	468222.	6378367.	788.

Total Equipment Investment in 1977: $13.47 million
Fraction of Investment made in Reinj. in 1977: .0000
Total Equipment Investment in 1983: $37.74 million
Platforms immediately abandoned: 2
Total Oil Production Foregone: 6.87 million Bbls
Total Associated Gas Production Foregone: 6.53 million MCF
Completion Lost before 1977: 0.
Production Lost before 1977: 0.

SOURCE: Arthur D. Little, Inc., estimates

TABLE VI-10

State Waters - Gas

Producers Absorb All Costs

Year	Production Loss by Platform Shut-ins in 1977 (MCF)	Production Loss by Platform Shut-ins in 1983 (MCF)	Production Loss by decrease in producing life (MCF)	Completion Abandonments
1977	0.	0.	0.	0.
1978	0.	0.	0.	0.
1979	0.	0.	0.	0.
1980	0.	0.	0.	0.
1981	0.	0.	0.	0.
1982	0.	0.	0.	0.
1983	0.	525006.	426616.	6.
1984	0.	462059.	291674.	0.
1985	0.	470611.	182975.	0.
1986	0.	357813.	80509.	0.
1987	0.	314809.	0.	0.
1988	0.	277094.	387932.	4.
1989	0.	243843.	1435931.	10.
1990	0.	214562.	2339210.	13.
1991	0.	188832.	2358360.	18.
1992	0.	85036.	3703563.	20.
1993	0.	0.	6202593.	68.
1994	0.	0.	7271577.	66.
1995	0.	0.	7287103.	43.
1996	0.	0.	3097643.	0.
1997	0.	0.	1494093.	29.
1998	0.	0.	38586.	0.
1999	0.	0.	1275954.	11.
2000	0.	0.	1035193.	7.
2001	0.	0.	1349376.	0.
2002	0.	0.	1533771.	11.
2003	0.	0.	2223619.	16.
2004	0.	0.	1176057.	0.
2005	0.	0.	7972769.	100.
2006	0.	0.	2780508.	0.
TOTAL	0.	3073572.	57306606.	422.

Total Equipment Investment in 1977: $5.87 million
Fraction of Investment made in Reinj. in 1977: .0000
Total Equipment Investment in 1983: $16.4 million
Platforms Immediately Abandoned: 0
Total Gas Production Foregone: 60.4 million MCF
Total Oil Production Foregone: .682 million barrels
Completion Lost Before 1977: 3.
Production Lost Before 1977: 0.31 million MCF

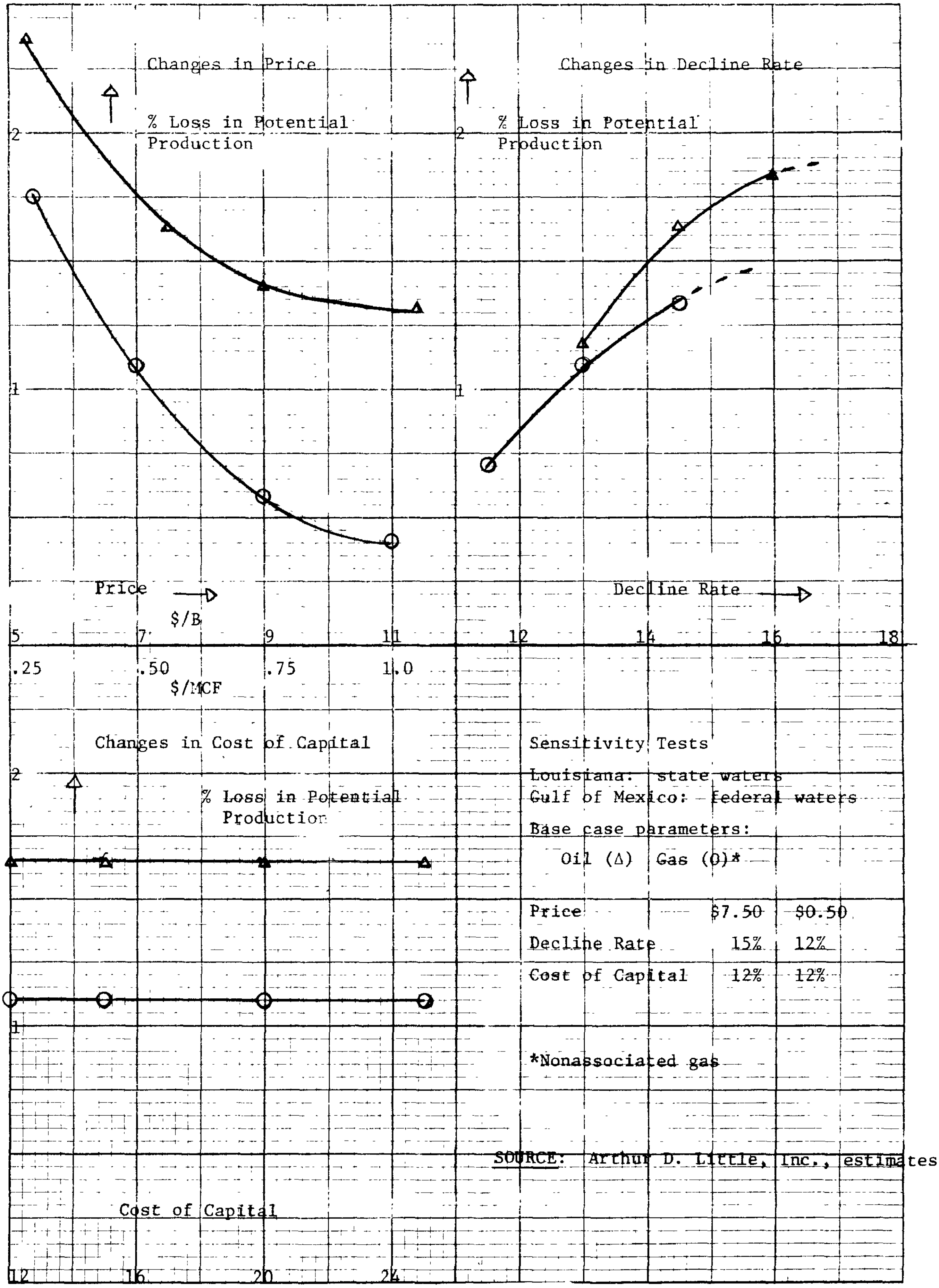
SOURCE: Arthur D. Little, Inc., estimate

- Investment in treatment equipment in 1977 will be \$5.87 million and investment in reinjection facilities in 1983 will be \$16.39 million amounting to a total investment of \$22.26 million.
- There will be no early abandonments in 1977 and not more than 6 in 1983 or 1.4% of completions producing in 1977.

It appears that a substantial number of oil completions will be producing close to the economic limit in 1983, resulting in early abandonment of 53 of a total of 786 still producing in 1982. Given the fact that these completions otherwise would have been phased out over a period of ten years, it can be expected that the reassignment of personnel directly involved in the production operations of these wells might pose a problem. This especially if the completions were part of one company's operations rather than being part of several companies' operations.

In the worst case this might even lead to lay-offs. Using one man for every two completions as a rough, direct employment indicator about 27 people could be affected by early abandonments of oil completions in 1983.

FIGURE VI-2



Changes in Price
% Loss in Potential Production
Price
$/B
$/MCF
5
7
9
11
.25
.50
.75
1.0
2
1
Changes in Decline Rate
% Loss in Potential Production
Decline Rate
12
14
16
18
Changes in Cost of Capital
% Loss in Potential Production
Cost of Capital
12
16
20
24
Sensitivity Tests
Louisiana: state waters
Gulf of Mexico: federal waters
Base case parameters:
Oil (Δ) Gas (O)*
Price $7.50 $0.50
Decline Rate 15% 12%
Cost of Capital 12% 12%
*Nonassociated gas
SOURCE: Arthur D. Little, Inc., estimates

State Waters; Sensitivity Tests by Changes in Base Case Parameters.

Sensitivity tests for state waters were made by changes in the following parameters:

- Changes in the "wellhead" price for oil, ranging from $5.25 to $11.00/bbl and for gas, ranging from $0.30 to $1.00 per MCF.
- Changes in the cost of capital, ranging from 12% to 25% for oil as well as for gas producers.
- Changes in the annual decline rate ranging from 12% to 18% per year for oil and 9% to 15% per year for gas.

The results of these tests are shown in Table VI-12 and Table VI-13 for oil and gas respectively and the changes in impact in terms of a percentage loss in potential production have been graphed as shown in Figure VI-2. Table VI-11 summarizes the results of the impact analysis for Louisiana state waters presenting the ranges within which the different impacts measured are likely to fall as indicated by the results of the sensitivity tests:

- The loss in potential production will be between 1.25 to 2.25% or 5.2 to 9.4 million barrels of oil and 5.0-9.0 million MCF associated gas from oil wells. For gas wells the loss will be 0.3% to 1.5% or 16.4 to 82.4 million MCF and 0.25-0.93 million barrels of condensate if no price increases are assumed for oil or gas.
- Completion abandonments in 1977 will amount to between 1 to 2 of a total 1213 producing oil and gas completions in 1977 and to between 42 and 75 of a total of 1211 producing oil and gas completions producing in 1983.
- Total investment requirements will be between $18.8 and $19.7 million in 1977 and between $49.7 and $56.4 million in 1983.

TABLE VI-11

Reinjection Required in 1983

Range of Likely Impact in Louisiana State Waters[1]

(1974 dollars)

Oil Wells			
Loss in Potential Prod.,	oil	1.25 - 2.25%	5.2 - 9.4 MMB
	ass. gas		5.0 - 9.0 MM MCF
Completions Abandoned in	1977	less than 0.3%	1 - 2
in	1983	5.0 - 8.4%	40 - 66
Investment Required in	1977		13.0 - 13.8 MM $
	1983		34.5 - 38.9 MM $
Gas Wells			
Loss in Potential Prod.,	gas	0.3 - 1.5%	16.4 - 82.4 MM MCF
	condensate		0.25 - 0.93 MMB
Completions Abandoned in	1977		0
in	1983	0.5 - 2.1%	2 - 9
Investment Required in	1977		5.82 - 5.92 MM $
	1983		15.2 - 17.5 MM $
Total Loss in Potential Prod.,	oil		5.45 - 10.33 MMB
	gas		21.4 - 91.4 MM MCF
Total Investment Req. in	1977		18.8 - 19.7 MM $
	1983		49.7 - 56.4 MM $
Total Completions Aban. in	1977		1 - 2
	1983		42 - 75

[1] Assuming producers absorb all costs.

SOURCE: Arthur D. Little, Inc., estimates

TABLE VI-11a

No Reinjection Required in 1983

Range of Likely Impact in Louisiana State Waters [1]

(1974 dollars)

Oil Wells			
Loss in Potential Prod.,	oil	0.6 - 1.1%	2.7 - 4.4 MMB
	ass. gas		2.6 - 4.2 MM MCF
Completions Abandoned in	1977	less than 0.3%	1 - 2
in	1983		NA
Investment Required in	1977		13.0 - 13.8 MM $
	1983		NA
Gas Wells			
Loss in Potential Prod.,	gas	0.16 - 0.8%	9.1 - 42.2 MM MCF
	condensate		0.1 - 0.5 MMB
Completions Abandoned in	1977		0
in	1983		NA
Investment Required in	1977		5.82 - 5.92 MM $
	1983		NA
Total Loss in Potential Prod.,	oil		2.8 - 4.9 MMB
	gas		11.7 - 46.4 MM MCF
Total Investment Req. in	1977		18.82 - 19.72 MM $
	1983		NA
Total Completions Aban. in	1977		1-2
	1983		NA

[1] Assuming producers absorb all costs.

SOURCE: Arthur D. Little, Inc., estimates

To show what difference it would make in terms of potential loss in production, investment requirements and early abandonments, an impact analysis for state waters was also done assuming that no reinjection would be required as of 1983. The results in Table VI-11a show that:

- The loss in potential oil and gas production will be about half of what will occur when reinjection is required in 1983.
- Investment requirements in 1977 will be the same, but total investment requirements will be about 25% of the total required in 1977 and in 1983 if reinjection in 1983 is required.
- Completion abandonments will be negligible.

TABLE VI-12

Sensitivity of Results to Changes in Key Variables

(1974 dollars)

State waters; reinjection required; oil

Producers Absorb All Costs

Varied Parameter	Value	% Loss of Potential Production Oil	Gas	Total Investment (in MM$) 1977	1983	Total	Number of Completions Abandoned 1977	1983	Number of Producing Completions End 1976
Price	$ 5.25	2.38	2.38	13.37	35.73	49.10	1	66	786
	*$ 7.50	1.64	1.64	13.47	37.74	51.21	2	53	788
	$ 9.00	1.40	1.40	13.47	37.74	51.21	2	53	788
	$11.00	1.33	1.33	13.47	38.88	52.35	2	40	788
Decline Rate	12%	1.19	1.19	13.85	40.24	54.09	2	40	788
	18%	1.83	1.83	13.09	34.43	47.52	2	66	788
Cost of Capital	15%	1.64	1.64	13.47	37.74	51.21	2	53	788
	20%	1.64	1.64	13.47	37.74	51.21	2	53	788
	25%	1.64	1.64	13.47	37.74	51.21	2	53	788
Extra Space Required		NA							
3 Platform Unit		NA							

*Base Case: 1 Platform Unit
Equipment Technology C
Price $7.50
Decline Rate 15%/year
Cost of Capital 12%/year

SOURCE: Arthur D. Little, Inc., estimates

TABLE VI-13

Sensitivity of Results to Changes in Key Variables

(1974 dollars)

State waters; reinjection required; gas

Producers Absorb All Costs

Varied Parameter	Value	% Loss of Potential Production Gas	Oil	Total Investment (in MM$) 1977	1983	Total	Number of Completions Abandoned 1977	1983	Number of Producing Completions End 1976
Price	$ 0.30	1.76	1.76	5.87	15.27	21.14	0	9	425
	*$ 0.50	1.10	1.10	5.87	16.39	22.26	0	6	425
	$ 0.75	0.58	0.58	5.87	17.11	22.98	0	4	425
	$ 1.00	0.41	0.41	5.87	17.47	23.05	0	2	425
Decline Rate	9%	0.71	0.70	5.92	17.18	23.10	0	4	425
	15%	1.34	1.34	5.82	15.20	21.02	0	11	425
Cost of Capital	15%	1.10	1.10	5.87	16.39	22.26	0	6	425
	20%	1.10	1.10	5.87	16.39	22.26	0	6	425
	25%	1.10	1.10	5.87	16.39	22.26	0	6	425
Extra Space Required		NA							
3 Platform Unit		NA							

*Base Case: 1 Platform Unit
Equipment Technology C
Price $0.50
Decline Rate 12%/year
Cost of Capital 12%/year

SOURCE: Arthur D. Little, Inc., estimates

Likely Average Cost Increases for Oil and Gas, State Waters

As explained in Section VI-4, producers might be able to pass on the additional costs they have to incur to comply with the new water treatment regulations.

Therefore, an estimate was made of the average cost increase for oil and gas which can be expected to result in state waters in 1977 and 1983 and which producers would like to pass on. For the calculations, it was assumed that producers would like to recover investment costs including a return on that investment and after tax operating costs over a period of 15 years following the investment.

The cost increase to be expected will then be the sum of the average per barrel capital charge and the average per barrel net increase in operating costs. These calculations are shown in Table VI-14. The results show that oil prices would have to be increased by 11.6¢ to 16.3¢ per barrel in 1977 and by about 77.3¢ to 107.9¢ per barrel in 1983 to allow producers to recover their additional costs. Gas prices would have to be increased by 0.41¢ to 0.57¢ per MCF in 1977 and by 2.41¢ and 3.31¢ per MCF in 1983.

TABLE VI-14

Likely Average Cost Increase in 1977 and 1983
for Producers in
State Waters
(1974 dollars)

		Oil Wells		Gas Wells	
		1977	1983	1977	1983
1.	Production in 1977/1983 (1)	66.7	25.0	689.2	320.0
2.	Production in 1991/1997 (1)	6.3	0.8	112.6	40.2
3.	Cum. Production (15 years) (1)	342.3	137.1	4228.4	2051.9
4.	Investment (MM $)	13.5	35.0	5.8	15.5
5.	Cap. Charge (4 x 2.8)/3	11.0 ¢/B	71.5 ¢/B	0.38 ¢/MCF	2.13 ¢/MCF
6.	Add. Op. Costs ($/yr)	1.2	3.4	0.55	1.82
7.	Add. Op. Costs (6 x 15)/3	5.2 ¢/B	37.2 ¢/B	0.20 ¢/MCF	1.33 ¢/MCF
8.	Add. Dep. Charge (4/3)	3.9 ¢/B	25.5 ¢/B	0.14 ¢/MCF	0.76 ¢/MCF
9.	Add After Tax Op. Cost 0.5 x (7-8)	0.6 ¢/B	5.8 ¢/B	0.03 ¢/MCF	0.28 ¢/MCF
10.	Cost Increase (Assuming 12% Annual Cap. Change)	11.6 ¢/B	77.3 ¢/B	0.41 ¢/MCF	2.41 ¢/MCF
11.	Cost Increase (Assuming 20% Annual Cap. Char	16.3 ¢/B	107.9 ¢/B	0.57 ¢/MCF	3.31 ¢/MCF

(1) In MMB or MM MCF

SOURCE: Arthur D. Little, Inc., estimates

VI.4. ALASKA, RESULTS OF A PRELIMINARY IMPACT ANALYSIS

The production and treatment economics developed for the Gulf of Mexico could not be applied to present offshore production in Alaska.

Industry sources indicated that operating cost levels are three-to-six-times higher than the operating cost level used for the Gulf of Mexico analysis. Investment levels can also be expected to be much higher given the harsher climate under which construction has to take place and longer distances from major supply centers.

The most important production statistics for the four oil fields and one gas field producing in the Cook Inlet are summarized in Table VI-15. Water production in each of the four oil producing fields is not sufficient to fulfill the needs for the pressure maintenance programs by water injection in those fields.

The seawater which is used for this purpose is chemically incompatible with the produced formation water, which precludes the use of a mixture of these types of water for reinjection purposes.(1) Therefore, only seawater is used for reinjection purposes, even though the high solids content of this water necessitates costly filtering before the water can be injected. Separation of produced fluids and water treatment on the platform is limited to free water knockout. All other treatment is done onshore by four large water treatment plants, one for each field. One of these plants is judged by the EPA to be capable of meeting 1977 treatment standards without any additional investment. All three others would require additional equipment or equipment modifications, the economics of which were not available. If the volumes of produced formation water increase to meet the total reinjection requirements by 1983, the use of produced formation water for pressure

(1) Information obtained through discussions with EPA representatives

TABLE VI-15

1973 Statistics on Oil and Gas Fields
Offshore Alaska, Cook Inlet(1)

Field Name	Number of Platforms	Number of Completions	Average Production in 1973: Oil (B/D)	Gas (MCF/D)	Water (B/D)	Water Reinjected Field Total (in B/D)
Granite Point	3	9	6,139	5,368	14	26,122
		7	3,307	3,812	54	
		9	3,613	3,199	202	
McArthur River	3	19	38,650	9,614	4,028	154,463
		23	42,982	16,200	5,689	
		12	24,771	7,429	7,806	
Middle Ground Shoal	4	7	3,350	1,512	202	55,950
		10	7,291	3,807	854	
		11	11,409	5,292	4,488	
		6	5,681	2,182	2,521	
Trading Bay	3	8	2,164	601	1,993	35,358
		31	15,168	7,637	3,917	
		5	4,105	1,157	5,118	
North Cook Inlet (Gas)	1	8	0	117,011	8	0

Source: "Statistical Report 1973," State of Alaska Department of Resources, Division of Oil and Gas.

intenance might be the economically most attractive way to comply with the
einjection requirement. In that case, no investment in reinjection facilities
ight be necessary in 1983. However, if this is not the case, then investment
n reinjection facilities for produced formation waters would be necessary in
983 either on the platform itself or onshore next to the existing treatment plants.

Cost estimates of these solutions were not available. Therefore, to indicate
n which range the impact from new regulations can reasonably by expected to fall,
wo cases were evaluated, both using estimates of operating and investment costs
or treatment and reinjection facilities of three and six times the costs used
r the Gulf of Mexico. The two cases differed in that the first case assumed the
eatment and reinjection facilities would be placed on the platforms and the
cond case assumed they would be placed onshore near the present treatment facilities

The results of this <u>preliminary</u> analysis of the first case are shown on
ble VI-16 and can be summarized as the following:

- If no investment in reinjection facilities would be required in 1983, and assuming that producers would have to absorb all costs, then:
    - Loss in potential production would range between 0.8 and 1.9% or 2.2 to 5.1 million barrels of oil and between 0.9 and 2.1% or 2.4 to 5.0 million MCF of associated gas.
    - No early abandonments would occur in 1977.
    - Total required investment would range from $12.6 to $25.1 million.
- If it is assumed that producers would be able to pass on all costs through a price increase, calculated in the same way as discussed in Sections VI-2.3 and VI-3.3
    - The required price increase in 1977 in terms of 1974 dollars would be between 14¢ per barrel and 28¢ per barrel, assuming a 12% cost of capital and between 21¢ per barrel and 42¢ per barrel, assuming a 20% cost of capital.

TABLE VI-16

Alaska, Cook Inlet

Preliminary Estimate of Likely Impact (3)

(1974 dollars)

1. Assuming Producers Absorb All Costs

	No Reinjection Req.		Reinjection Req.(4)	
	3x(1)	6x(1)	3x(1)	6x(1)
Potential Prod. Oil (MMB)	280	263	280	263
Ass. Gas (MM MCF)	261	242	261	242
Loss in Pot. Prod. (MMB)	2.2	5.1	6.8	14.7
(MM MCF)	2.4	5.0	7.0	16.7
% Loss in Pot. Prod: Oil	0.8	1.9	2.4	5.6
Ass. Gas	0.9	2.1	2.7	6.9
Early Abandonments, 1977	0	0	0	0
1983	NA	NA	8 (= 5%)	54 (= 34%)
Investment Required, 1977	12.6	25.1	12.6	25.1
(in MM$) 1983	NA	NA	35.0	54.7

2. Increases in Average Cost per Unit Produced

Average Cost Increase Oil(2)	in ¢/B		in ¢/B	
Cost of Capital 12%, 1977	14	28	14	28
1983	NA	NA	46.0	71.0
Cost of Capital 20%, 1977	21	42	21	42
1983	NA	NA	167	313

(1) 3 x: Assuming all operating and investment costs are 3 x as high as in the Gulf of Mexico.
6 x: Assuming all operating and investment costs are 6 x as high as in the Gulf of Mexico.

(2) Based on a calculation of the per-barrel after tax operating costs plus investment costs including a return on that investment over a period of 15 years.

(3) Assuming treatment facilities will be put on each of fourteen oil production platforms.

(4) Assuming that reinjection facilities on platforms will be necessary in addition to existing injection plants used for pressure maintenance.

SOURCE: Arthur D. Little, Inc., estimates

- If investment reinjection in facilities would be required in 1983 and assuming that producers would absorb all costs, then:
  - Loss in potential production would range between 2.4 and 5.6% or 6.8 and 14.7 million barrels of oil and between 2.7 and 6.9% or 7.0 and 16.7 million MCF of associated gas.
  - Early abandonments in 1983 would be between 8 and 54 or between 5% and 34% of total producing completions in 1977.
  - Total investment required would be between \$12.6 and \$25.1 million in 1977 and between \$35.0 and \$54.7 million in 1983.
- If it is assumed that producers would be able to pass on all costs as price increases and that they would calculate these price increases as described in Sections VI-2.3 and VI-3.3, then:
  - The required price increase would be 6.3¢ to 11.4¢ per barrel in 1977 and 46¢ to 71¢ per barrel in 1983;

    with a cost of capital of 20% the required price increase would be between 6.6¢ and 12.2¢ per barrel in 1977 and between 49¢ and 77¢ per barrel in 1983.

The second case assumed that producers would decide to add the required treatment and reinjection facilities to each of the four existing onshore treatment plants.(2) The results of this preliminary analysis in Table VI-17 show that:

- If no reinjection would be required in 1983 and assuming that producers would absorb all costs, then:
  - Loss in potential production would be between 0.7 and 1.9% or 2 to 5 million barrels of oil and between 0.8 and 2.0% or 2.2 to 4.9 million MCF of associated gas.

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(2) To the extent that additional treatment equipment might not be required for one plant as mentioned in the discussion, the estimation impact by additional treatment requirements will be too high.

TABLE VI-17

Alaska, Cook Inlet

Preliminary Estimates of Likely Impact (3)

(1974 dollars)

1. Assuming Producers Absorb All Costs

	No Reinjection Req.		Reinjection Req.(4)	
	3x(1)	6x(1)	3x(1)	6x(1)
Potential Prod. Oil (MMB)	280	263	280	263
Ass. Gas (MM MCF)	261	242	261	242
Loss in Pot. Prod. (MMB)	2.0	5.0	3.6	11.1
(MM MCF)	2.2	4.9	4.1	12.2
% Loss in Pot. Prod: Oil	0.7	1.9	1.3	4.2
Ass. Gas	0.8	2.0	1.6	5.0
Early Abandonments, 1977	0	0	0	0
1983	NA	NA	0	44.0
Investment Required, 1977 (in MM$)	7.7	15.5	7.7	15.4
1983	NA	NA	25.7	43.1

2. Increases in Average Cost per Unit Produced

Average Cost Increase(2)	in ¢/B		in ¢/B	
Cost of Capital 12%, 1977	9	17	9	17
1983	NA	NA	81	157
Cost of Capital 20%, 1977	13	26	13	26
1983	NA	NA	127	247

---

(1) 3 x: Assuming all operating and investment costs are 3 x as high as in the Gulf of Mexico.
6 x: Assuming all operating and investment costs are 6 x as high as in the Gulf of Mexico.

(2) Assuming producers pass on the per-barrel after tax operating costs plus investment costs including a return on that investment over a period of 15 years.

(3) Assuming treatment and reinjection facilities onshore - one for each of four oil producing fields.

(4) Assuming reinjection facilities will be necessary in addition to existing injection plants for pressure maintenance purposes.

SOURCE: Arthur D. Little, Inc.

- No early abandonments would occur in 1977.
- Total required investment would range from \$7.7 to \$15.4 million.

- If it is assumed that producers would pass on all costs through a price increase, then:
  - The required price increase in 1977 in terms of 1974 dollars would be between 3.8¢ per barrel and 7.6¢ per barrel for a 12% cost of capital and 4¢ to 7.6¢ per barrel if calculated with a 20% cost of capital.
- If reinjection would be required in 1983 and assuming that producers would absorb all costs, then:
  - Loss in potential production would range between 1.3 and 4.2% or 3.6 and 11.1 million barrels of oil and between 1.6 and 5.0% or 4.1 to 12.2 million MCF of associated gas.
  - Early abandonments in 1983 would be between 0 and 44 or between 0% and 28% of total producing completions in 1977.
  - Total investment required would be between \$7.7 and \$15.4 million in 1977 and between \$25.7 and \$43.1 million in 1983;
- If it is assumed that producers would pass on all costs as price increases and that they would calculate these price increases as described in Section VI-2.3 and VI-3.3, then:
  - The required price increase would be between 9¢ and 26¢ per barrel in 1977 and between 81¢ and 247¢ per barrel in 1983.

VI.5. CALIFORNIA

There are 14 producing platforms off of California, nine in state waters and five in Federal waters. In addition, there are seven man-made islands on which wells are producing offshore in state waters. (See Table VI-18).

All of the produced formation water from offshore facilities on state and Federal leases is sent ashore for processing and disposal. The formation water produced from facilities in Federal waters four to five miles offshore is piped ashore, treated and returned to the platforms for reinjection. Of the nine platforms in state waters, four have their production piped to one onshore processing facility and the other five to five separate processing plants.

Most formation water is reinjected for pressure maintenace. A small portion is treated onshore and pumped into the ocean; while accurate data is not available, the percentage of offshore produced formation water discarded into the ocean has been estimated at 3.9% of total produced brine in 1974.[1] The 1974 brine production was 293.3 million barrels. If the same percentage tage is applied [illegible] [illegible]73, the volume of formation water discarded is 10.9 million barrels. In addition to the brine from offshore production, about 16 million barrels of formation water from onshore wells is discarded into the ocean.[1] This is about 2.3% of total onshore water produced with oil and gas in the coastal basins.

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[1] Estimate made by Mr. John Hardoin, California Division of Oil and Gas, Long Beach.

TABLE VI-18

California; Platforms and Offshore Oil,

Gas and Water Production

in 1973[1]

	State Waters	Federal Waters
Number of Platforms	9 + 7[2]	5
Oil production MMB	70.5	18.8
Associated Gas MM MCF	20.9	9.1
Non Associated Gas MM MCF	9.7	0.0
Water Associated MMB with Oil	266.0	12.2
Water Associated MMB with Gas	0.5	0.0

(1) Source: "Oil, Gas and Geothermal Production Statistics, 1973." Resources Agency of California, Vol. 59, No. 2.

(2) 9 Platforms and 7 man-made islands.

California has enacted a brine disposal requirement that is more restrictive than the proposed Federal effluent guidelines for 1977. California regulations require water to be discharged in the ocean to be treated to 20 parts per million (ppm) long-term average of oil and grease. The Federal requirements are a 27 ppm long-term average. Unlike the produced formation water from the Gulf of Mexico, the California formation water has far lower salinity and is typically less saline than the sea water.

The proposed EPA 1977 effluent guidelines do not appear to impose an additional burden on California offshore production. The California state requirement resulted in Phillips shutting in and removing one platform and Texaco stopping production on two others in 1973 when the requirements went into effect.

VI.6. INFERRED IMPACT, EXISTING SOURCES IN THE GULF OF MEXICO

The estimates of the total impact in federal and state waters was based on units already producing in 1974. It can be expected that by 1977 quite a few additional wells will have been drilled. Therefore, the total number of, what the EPA considers to be "existing sources,"[1] will be larger than the number of production units considered in the earlier analysis.

To obtain an idea of how much this actual number of existing sources will differ from the number of sources considered, the total reserves implied[2] by the analysis was compared with the sum of demonstrated and inferred reserves as defined and estimated by the U.S.G.S.[3]

The underlying assumption was that demonstrated and inferred reserves will be produced by wells existing in 1974 and wells to be drilled until 1977 in federal waters and existing wells plus wells drilled until 1983 in state waters.

Assuming that the relative number of wells in federal and state waters would remain the same and assuming that the measured impacts would be extrapolated on a unit of reserves basis an estimate was made of the total impact for these existing sources.

The results of this calculation using the assumptions for the base case are shown in Table VI- 19 and Table VI-20.

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(1) "Source" in this context should be understood to mean point source of discharged water.

(2) Implied reserves consisted of the total potential production of all completions considered.

(3) "Geological estimates of undiscovered recoverable oil and gas resources in the United States," Geological Survey circular 725, 1975.

TABLE VI-19

Total Inferred Impact for Existing Sources in the Gulf of Mexico as Derived from the Measured Impact

Producers Absorb All Costs
(1974 dollars)

		Recoverable Reserves		Potential Prod. Lost		Required Investment
		Oil MMB	Gas MM MCF	Oil MMB	Gas MM MCF	MM $
	Gulf of Mexico, Oil Wells					
	Federal, measured impact			14.0	40.3	63.9
	Implied reserves	1590	3600			
	State, measured impact			6.9	6.5	51.2
	Implied reserves	419	398			
1	Total measured impact			20.9	46.8	115.1
2	Total implied res.(1)	2233				
3	U.S.G.S. reserves (2)&(4)	4612				
4	Inferred total impact (1x(3:2)) =			43.2	96.6	237.7
	Gulf of Mexico, Gas Wells					
	Federal, measured impact			1.1	75.4	23.5
	Implied reserves	162	14743			
	State, measured impact			0.7	60.4	22.3
	Implied reserves	62	5471			
5	Total measured impact			1.8	135.4	45.8
6	Total implied res.(3)		24212			
7	U.S.G.S. reserves(2)&(4)		102834			
8	Inferred total impact (5x(7 :6)) =			7.6	575.1	194.5
	Total Gulf of Mexico (4+8) =			50.8	671.7	432.3

(1) Including condensate produced with nonassociated gas.

(2) Source: "Geological estimates of undiscovered recoverable oil and gas resources in the United States," Geological Survey circular 725, 1975.

(3) Including associated and dissolved gas to be produced with oil.

(4) Including Demonstrated and Inferred Reserves.

SOURCE: Arthur D. Little, Inc., estimates

TABLE VI-20

Total Inferred Impact for New Sources in the Gulf of Mexico

Producers Absorb All Costs
(1974 dollars)

		Recoverable Reserves		Potential Prod. Lost		Required Invest-ment
		Oil MMB	Gas MM MCF	Oil MMB	Gas MM MCF	MM $
	Gulf of Mexico, Oil Wells					
1	Federal, measured impact			14.0	40.3	63.9
2	Implied reserves(1)	1752				
	Undiscovered(2)					
3	Recoverable resources	3000-8000				
4	Inferred impact (1 x (3:2)) =			24.0-64.	69.-184	109.-292.
	Gulf of Mexico, Gas Wells					
5	Federal, measured			1.1	75.4	23.5
6	Implied reserves(3)		18,343			
	Undiscovered					
7	Recoverable resources		18,000-91,000			
8	Inferred impact (5 x (7:6)) =			1.1-5.5	75.4-374.	23.5-116.6
	Total inferred impact (4 + 8) =			25.1-69.5	144.4-558.	132.5-408.6

(1) Including condensate produced with nonassociated gas.

(2) Source: "Geological estimates of undiscovered recoverable oil and gas resources in the United States," Geological Survey circular 725, 1975.

(3) Including associated and dissolved gas to be produced with oil.

SOURCE: Arthur D. Little, Inc., estimates

According to these results, loss in potential oil production, including lease condensate, will be 50.8 million bbls and loss in potential gas production, including associated gas, will be 671.7 million MCF; total investment requirements in 1977 and 1983 will amount to $432.2 million.

Given the gross assumptions which were made in deriving these numbers, they should be regarded to be no more than a very rough estimate, which might be off by as much as a hundred percent.

VI.7. INFERRED IMPACT, NEW SOURCES IN THE GULF OF MEXICO

The earlier sections of this chapter have presented estimates of foregone production from wells existing in 1974 and the required investments in treatment and reinjection facilities for these wells resulting from the application of the effluent limitations guidelines. As explained in Chapter III, the EPA is also proposing a New Source Performance Standard (NSPS) guideline applicable to all new wells in both state and Federal waters which is identical in its requirements to the 1983 guidelines for wells which were already producing prior to 1977 except that it becomes applicable in 1977. This implies that new wells in state waters as of 1977 will be required to reinject all produced formation water and new wells in federal waters must comply with the BATEA/NSPS requirements in 1977.

A rough worst case estimate can be made of the foregone production resulting from the application of the NSPS requirements to wells beginning production in 1977 and thereafter. The majority of these new wells are expected to be in federal waters, not state waters. To simplify the estimating process, which is crude at best, the assumption has been made that all new wells after 1977 will be in federal waters, which implies that there will be no reinjection requirement for these wells.

The U.S. Geological Survey has published estimates of the total recoverable resources from the U.S. given existing production technology.[1]

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(1) "Geological estimates of undiscovered recoverable oil and gas resources in the United States" Geological Survey Circular 725, 1975.

Table VI-21 lists the resource estimates for the offshore areas. The estimates can be regarded as an approximate estimate of the total lifetime production from all new offshore oil and gas wells in the futuie. As production technology and the relative cost of other energy sources change in the future the volumes of oil and gas which may ultimately be produced from U.S. offshore wells can also change. However, the U.S. G.S. resource estimates at least provide one basis from which the long term production losses resulting from the proposed regulations can be estimated.

The earlier analysis of potential production losses from the application of BPCTCA and BATEA requirements to wells in federal waters which were producing in 1974 showed that 0.5% to 1.0% of their remaining lifetime oil production and 0.2% to 0.75% of their remaining lifetime production of gas would be lost if prices could not be increased to recover the pollution control costs. Table VI-20 lists the projected production losses if these percentages are applied to the U.S.G.S. resource values.

Using this estimating proceedure as demonstrated in Table VI-19 for new sources in the Gulf of Mexico, the projected loss in potential production is 25 to 70 million barrels of oil and 144 to 558 million MCF of gas. These losses would be stratched out over the entire period of offshore U.S. production beyond 1977. Most of the potential losses would not occur until after the year 2000.

The estimate of total investment was made in a similar way as demonstrated in Table VI-20. First, investment required for future oil

TABLE VI-21

Total Inferred Impact for New Sources
Offshore U.S.A.(1)

(1974 dollars)
Producers Absorb All Costs

	Rec. Resources(2)		Potential Prod. Lost(3)		Required(4)
	Oil Billion Bls	Gas Billion MCF	Oil Billion Bls	Gas Billion MCF	Investment Billion $
Gulf of Mexico	5.4-8.0	18.0-91.0	.03-.07	.14-.56	.13-.41
Alaska	3.0-31.0	8.0-80.0	.03-.25	.10-1.04	.12-1.35
Atlantic Coast	2.0-4.0	5.-14.0	.02-.03	.06-.15	.08-.16
Pacific Coast	2.0-5.0	2.0-6.0	.01-.07	.05-.14	.08-.19
Total			.08-.35	.30-1.75	.33-1.92
			.11-.38	.65-1.89	.53-2.12

(1) Based on base case results for the impact analysis for old sources and as such presenting a lower limit for the estimated impact for new sources.

(2) Source:
"Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States," Geological Survey circular 725, 1975.
The low and high estimates have been made at the 95% and 5% confidence levels respectively.
Source: Arthur D. Little, Inc. calculations based on U.S.G.S. estimates of recoverable resource.

(3) Expected to occur over a period of about 50 years starting between 1990 and 2000.

(4) Expected to be required over a period of at least 25 years following 1977.

SOURCE: Arthur D. Little, Inc., estimates

and gas producing wells in each area considered was estimated multiplying the estimated investment requirement per unit of estimated remaining reserves in 1977 for wells producing in 1974 by the total estimates of total recoverable oil and gas resources respectively. The total investment requirement shown in Table VI-21 was obtained by summing these estimates obtained for oil and gas resources.

In addition to the uncertainty about the resource values themselves, there are several potential errors from simply multiplying the percentage loss from 1974 wells times the resource estimates. The percentages are the portion of the remaining life after 1977 of the wells existing in 1974.

All of these wells have been producing prior to 1974. This implies that the estimated percentage loss of remaining production in 1977 is considerably higher than it would have been if this percentage would have been calculated using the total lifetime production of these wells.

As a result, the estimated loss in potential production for new wells, which has derived by multiplying this percentage obtained for 1974 wells with the estimated total lifetime production for new wells (i.e. estimated total recoverable resources), should be too high.

For the same reasons the investment estimates for new sources derived by using investment requirements per unit of potential production of wells producing in 1974 might be too high.

On the other hand, this upward bias in estimated loss in potential production may be mitigated by the fact that much of the new production will be from wells in areas with higher production costs such as Alaska and the Atlantic. It can be expected that the cost of compliance per well or unit of production in these areas will be higher than was assumed in the Gulf of Mexico analysis which will result in higher losses of potential production.

The relative weight of these opposing biases is not known. However, they do suggest the approximate nature of the estimates.

VI.8. DIRECT ENERGY EFFECTIVENESS OF TREATMENT EQUIPMENT

The following analysis has assumed that EPA's estimate that a long-term average of 27 ppm of effluent hydrocarbon concentration is achievable with the application of the BPCTCA regulation. See Chapter III for a discussion of the analysis behind the assumptions.

The average hydrocarbon influent concentration of all units considered by Brown & Root[1] was 196 ppm. Based on this information, an average of 169 ppm (mg oil per liter of water treated) to be recovered by treatment of produced formation waters will be used in this analysis of the direct energy effectiveness of treatment equipment.

This 169 ppm of recoverable crude oil corresponds with 2.02 bbl of oil recovered per 10,000 bbls of water treated.

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[1]Brown & Root report, page IV-8.

Figure VI-3 taken from the Brown & Root report shows the horsepowers required as a function of treatment capacity for treatment by flotation and treatment by coalescence, respectively. Based on these graphs, the horsepower requirements for flotation equipment used in the following analysis will be 1 HP/344 barrels water treated. Treatment by gravity separation using pits or tanks has a negligible energy requirement.

To inject 1 bbl/day of water at 1 psi pump pressure, 1.7×10^{-5} HP pump power is required.

Assuming that 80% of the total installed pump capacity will be used, one will need $2.125\ 10^{-5}$ HP installed pump capacity for each barrel of water reinjected at a discharge pressure of 1 psi.

Assuming a 3000 foot deep reinjection well and knowing that the overburden pressure decreased by the hydrostatic is about 0.5 psi/foot, we know that the maximum discharge pressure cannot exceed 1500 psi. Using 1300 psi as the maximum injection pressure at the pump ($1300 \times 2.125\ 10^{-5}$) or .0276 HP will have to be installed for each daily barrel of water to be reinjected.

A daily volume of 1000 barrels per day will thus require 27.6 HP of installed pump power.

One HP delivered during one day is equivalent to .061 MCF of natural gas or to .0101 barrels of diesel oil.[1]

Assuming a conversion efficiency of 20%, 5 x .061 = .305 MCF/day natural gas or 5 x .0101 = .0505 bbls/day diesel oil will be required for each HP-day.

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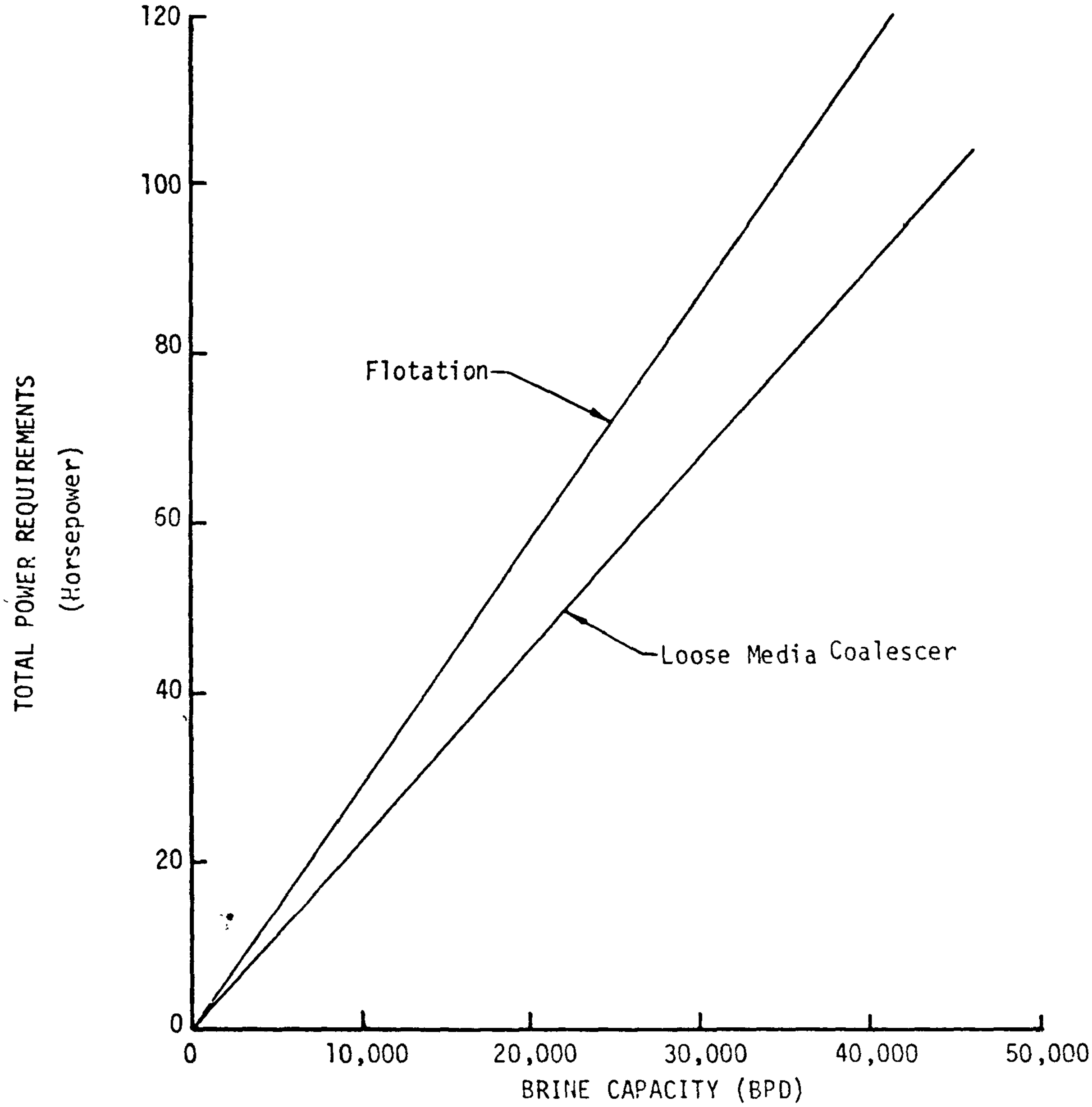
(1) Approximately:	1 bbl diesel oil	≃	6000 Btu
	1 bbl crude oil	≃	5850 Btu
	1 MCF natural gas	≃	1000 Btu

FIGURE VI-3

POWER REQUIREMENTS
FOR BRINE TREATMENT SYSTEMS



NOTES:
1. Flotation power requirements are based on an induced gas flotation device and includes power for operating motors.
2. Loose media coalescer power requirements are based on power for influent, flush, and flush water disposal pumps.

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Direct energy effectiveness, as used here, is the ratio of number of barrels of crude oil recovered by treatment over number of barrels of diesel oil equivalent required by the treatment (and reinjection) equipment.

Using these values it is estimated that by treatment with flotation units, on the average, 1 barrel of diesel oil equivalent will have to be consumed for treatment of 6850 barrels of water to recover 1.4 barrels of crude oil.

When treated formation waters are reinjected, then only .13 barrels of crude oil will be recovered for each barrel of diesel oil required for treatment plus reinjection of 719 barrels of water.

In terms of natural gas the requirement would be for 1 MCF natural gas to recover 0.23 barrel of crude oil from 1141 barrels of treated formation water. However, 1 MCF natural gas will only treat and reinject 120 barrels of formation water from which .022 barrels of crude oil will be recovered.

This analysis estimates the total energy recovery from the BPCTCA treatment system. The analysis is not intended to represent the incremental energy recovery from the application of the BPCTCA guidelines. The platforms in federal waters presently are under a 50 ppm long-term average requirement of the USGS. Thus, the incremental oil recovery resulting from compliance with the BPCTCA requirement is 23 ppm per barrel of formation water treated.

VI.9. ECONOMIC COST PER BARREL RECOVERED

Given the fact, shown in the previous section, that on the average the treatment equipment expected to be installed in 1977 will recover more energy than it consumes, it was of interest to consider the economic cost[1] of the average additional barrel recovered by the BPCTCA facilities. (See Table VI-22 and Table VI- 23.) For the calculation of this economic cost it was assumed that producers would expect to recover their investment plus a return on that investment over a period of 15 years in addition to net after tax operating costs incurred for the treatment equipment during that same period.

An estimate of maximum and minimum number of barrels of oil recovered during the 15 years considered was made.

The minimum estimate was based on the average water/oil and water/gas ratio in 1974 of all platforms considered, assuming that this ratio would not increase during the next 18 years.

The maximum estimate was obtained assuming that platforms would produce the maximum amount of water considered to be possible based on the engineering considerations and analysis of actual water/oil and water/gas ratios as discussed in the previous chapter.

Minimum and maximum amount of oil recovered was calculated using the average recovery factor of 2 barrels of oil per 10,000 barrels of water treated as derived in the previous section.

Using investment and operating cost estimates developed in previous sections, the capital charge and total increase in after tax operating costs

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(1) Economic cost is supposed to mean the average cost per barrel recovered allowing for the additional operating and investment costs which have to be incurred for recovery equipment.

for the 15-year period could be calculated. The sum of these two cost items divided by the total number of barrels recovered during the 15 years resulted in the estimate of minimum and maximum economic cost per barrel of oil recovered (See Table VI-22 and Table VI-23). The results show that:

- For federal waters the economic cost per barrel recovered by treatment of produced formation water will range from $94 to $2382 for oil producing units and from $42 to $4511 for gas producing units.
- For state waters the economic cost per barrel recovered will range from $36 to $1237 for oil producing units and from $133 to $2984 for gas producing units.

Reinjection is not really part of the treatment installation but it could be argued that the barrels of oil recovered by treatment should also pay for the additional costs incurred for reinjection in state waters starting in 1983. Therefore, the economic cost per barrel recovered was also calculated for reinjection facilities, which may be required in 1983. The range of $371 to $8321 for oil producing facilities and $808 to $17741 for gas producing facilities (see Table VI-19) derived as the economic cost per barrel of oil recovered for treatment and reinjection installations, shows that the reinjection requirement increases the economic cost by about a factor of nine.

TABLE VI - 22

Economic Cost per Barrel of Oil Recovered
Federal Waters
(1974 Dollars)

		Oil Wells		Gas Wells	
		1977	1983	1977	1983
1.	Cumulative Production (15 yrs.)(MMB/MM MCF)	1296.5	N/A	11328.5	N/A
2.	Minimum[a] Water Production (MMB)	648.3		85.0	
3.	Minimum Oil Recovered (MB)	129.7		17.0	
4.	Maximum[b] Water Production (MMB)	6555.9		1891.9	
5.	Maximum Oil Recovered (MB)	1311.0		378.4	
6.	Investment (MM$)	40 - 100		5 - 25	
7.	Capital Charge (6x 2.8)(MM$)	112.0 - 280		14.0 - 70	
8.	Added Op. Costs (15 yrs.)(MM$)	51 - 129		6.8 - 31.7	
9.	Added Dep. Charge (15 yrs.)(MM$)	40 - 100		5 - 25	
10.	Net Increase in Op. Cost (8-9)(MM$)	11 - 29		1.8 - 6.7	
11.	Minimum Ec. Cost per Bbl Recovered ((7+10)/5)($/B)	94		42	
12.	Maximum Ec. Cost per Bbl Recovered ((7+10)/3)($/B)	2382		4511	
13.	Ec. Cost Range ($/B Recovered)	94 - 2382		42 - 4511	

(a) Assuming 0.5 Bbl water per Bbl of oil and .0075 Bbl water per MCF gas in 1977.

(b) Assuming (oil prod. + water prod./.7) = constant and .167 Bbl water per MCF gas in 1977.

SOURCE: Arthur D. Little, Inc., estimates

TABLE VI -23

Economic Cost per Barrel of Oil Recovered
State Waters
(1974 Dollars)

		Oil Wells		Gas Wells	
		1977	1983	1977	1983
1.	Cumulative Production (15 yrs.) (MMB or MM MCF)	342.3	137.1	4228.4	2051.9
2.	Minimum[(a)] Water Production (MMB)	171.2	68.6	31.7	15.4
3.	Minimum Oil Recovered (MB)	34.2	13.7	6.3	3.1
4.	Maximum[(b)] Water Production (MMB)	5882.0	1537.0	706.0	342.0
5.	Maximum Oil Recovered (MB)	1176	307	141	68
6.	Investment (MM$)	13.5	35	5.8	15.5
7.	Capital Charge (6x 2.80) (MM$)	37.8	98	16.3	43.5
8.	Added Op. Costs (15 yrs.)(MM$)	18	51	8.3	27
9.	Added Dep. Charge (15 yrs.)(MM$)	13.5	35	5.8	15.5
10.	Net Increase in Op. Costs 0.5 x (8-9) (MM$)	4.5	16	2.5	11.5
11.	Ec. Cost per Bbl Recovered ($/B)	36 - 1237	371 - 8321	133 - 2984	808 - 17741

(a) Assuming 0.5 Bbl water per Bbl of oil and .0075 Bbl water per MCF gas in 1977.

(b) Assuming (oil prod. + water prod./.7) = constant and .167 Bbl water per Bbl MCF gas in 1977.

SOURCE: Arthur D. Little, Inc., estimates