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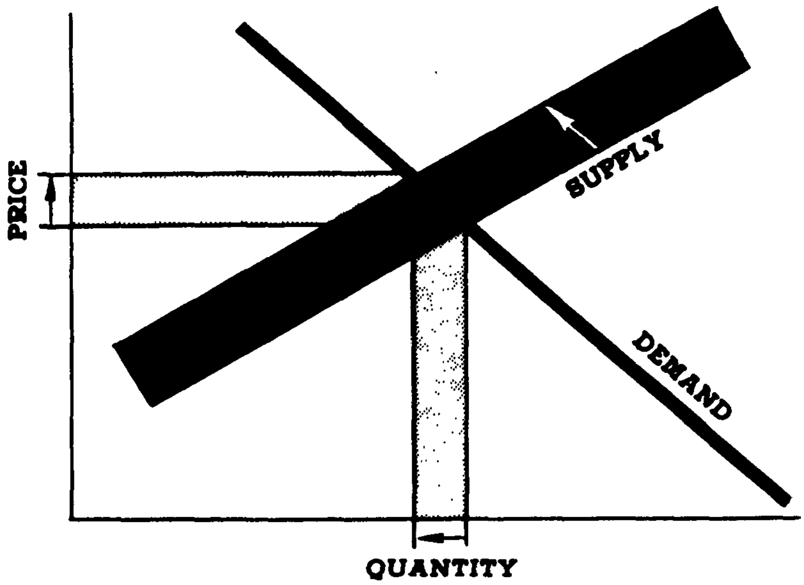
ECONOMIC ANALYSIS OF PROPOSED AND INTERIM FINAL EFFLUENT GUIDELINES FOR

THE ONSHORE OIL PRODUCING INDUSTRY



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

ECONOMIC ANALYSIS

OF

PROPOSED AND INTERIM FINAL EFFLUENT GUIDELINES

FOR

THE ONSHORE OIL PRODUCING INDUSTRY

(non-stripper wells)

report to

U.S. Environmental Protection Agency

Office of Analysis and Evaluation

Office of Water and Hazardous Materials

Washington, D.C. 20460

Partial Fulfillment of
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TABLE OF CONTENTS

LIST OF TABLES

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF FIGURES

I. EXECUTIVE SUMMARY

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 (BPT) and the 1983 Best Available Technology (BAT) for onshore oil production from wells with an average production greater than ten barrels per day. 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 estimated the number of wells in Louisiana, Texas and Wyoming which would be shut in rather than brought into compliance, the investment required by the operators to come into compliance, the volume of oil production foregone as a result of the guidelines, and the average increase in the cost of oil production.

The characterization of the oil well populations in the impact states and the costs of compliance were developed by Jacobs Engineering, Inc., under another contract with EPA.

Significant volumes of salt water are produced along with oil from oil wells. The water associated with most U.S. onshore oil production is pumped back into the ground in a reinjection well. However, large volumes of produced formation water from perhaps 25% of the wells are discharged to surface waters. Table I-1 lists the number of wells and production by state.

The impacts of the proposed guidelines were examined in Wyoming, Texas and Louisiana. Texas and Louisiana production is divided into platform and on-land wells. A small number of platforms in estuaries and bays are classified as onshore. In Wyoming much of the currently discharged water is of comparatively low salt content and is used for watering livestock.

TABLE I-1

CHARACTERIZATION OF AFFECTED PRODUCTION

	Total Number of Wells per State[a]	Number of Potentially Impacted Wells	Total State 1975 Oil Production[a] (bbl's/day)	Potentially Impacted Production (bbl's/day)
Louisiana				
on land	15,829	715	773,189	64,513
on platform		1,033		156,394
Texas				
on land	71,226	1,108	3,000,362	82,761
on platform		456		10,027
Wyoming	6,821	1,594	130,836	89,853
Total	93,876	4,906	3,904,387	403,548

a. Includes non-stripper, on-land wells and all "onshore" wells producing to platforms. See Table V-1 for total state production statistics.

SOURCE: Petroleum Statement, March 1976, U.S. Bureau of Mines; Jacobs Engineering

Texas, Louisiana, and Wyoming contain 42% of the onshore U.S. wells in 1975 producing more than ten barrels per day, including those in coastal areas producing to platforms. These states have 71% of the crude production from onshore wells producing more than ten barrels per day.

The three impact states may have as many as 24,000 wells whose formation water is not currently reinjecting, including stripper wells. These wells may be 70% of the currently non-reinjecting wells in the 17 largest oil-producing states, excluding Illinois, which has predominantly stripper wells. Their non-stripper production whose brine is not currently reinjected is estimated to be 72% of the total U.S. onshore, non-stripper production whose brine is not reinjected.

2. Summary of Conclusions

The impact of a requirement that formation water from wells producing more than ten barrels per day be reinjected into the ground appears to be small in Texas, Louisiana, and Wyoming. The primary results of the impact analysis shown on Tables I-2 and I-3 can be summarized as follows.

- A requirement to reinject formation water from existing near-shore platforms would result in the closure of about 2% of the Louisiana platforms and 64% of the Texas platforms. An effluent treatment rather than a reinjection requirement would substantially reduce the number of well closures.
- The reinjection requirement is not expected to close any on-land, non-stripper wells in Louisiana and Texas, but could close as many as 144 wells in Wyoming.

TABLE I-2

ESTIMATED WELL CLOSURES AND PRODUCTION LOSSES

	Number of Wells Closed[a]	Percent of Impacted Wells Closed[a]	Wells Closed as a Percent of All Wells Covered by Regulation[a]	Production Foregone[b] (MM bbl's)	Foregone Production As a Percent of Potential Production by Impacted Wells[b]	Foregone Production As a Percent of Total State API Reserves[c]
Louisiana						
on land	0	0%	0%	1.1	0.4%	0.03%
on platforms[d]	21	2	0.1	6.0	0.9	0.2
Texas						
on land	0	0	0	1.9	0.5	0.02
on platforms[d]	291	64	0.4	11.1	27	0.1
Wyoming	144	9	2.1	11.4	3.0	1.3
Total	456	9%	0.5%	31.5	1.8%	0.2%

a. Wells closed rather than brought into compliance with a reinjection requirement.
b. Production lost by immediate well closures plus shorter well life due to higher operating costs.
c. Offshore reserves included.
d. The effluent treatment requirement would close an estimated 2 and 110 wells on Louisiana and Texas platforms respectively.

SOURCE: Arthur D. Little, Inc.

TABLE I-3

ESTIMATED COST OF COMPLIANCE WITH REINJECTION REQUIREMENT

	Investment Requirement ($MM)	Increased Operating Cost ($MM)	Increased Operating Cost ($/bbl)	Increase in Total Production Costs[a] ($/bbl)
Louisiana				
on land	6.05	.82	0.04	0.22
on platform[b]	38.4	2.89	0.05	0.48
Texas				
on land	11.5	2.03	0.07	0.31
on platform[b]	5.3	.35	0.19	1.43
Wyoming	18.2	1.99	0.07	0.34
Total	80	8.1	0.06	0.34
Total U.S.	110	11	NA	NA

a. Present value of total compliance costs averaged over total remaining production.
b. The effluent treatment requirement would require $8.6 MM for Louisiana platforms and $4.5 MM for Texas platforms.

SOURCE: Arthur D. Little, Inc., estimates

- The investment required to install reinjection equipment in the three states, including platforms, is $80 million. It is estimated that the total U.S. requirement is roughly $110 million. This level of investment spread over several years is modest compared to $3-5 billion projected as yearly capital expenditures by the industry on onshore oil and gas production.
- The reinjection requirement would result in approximately 32 million barrels of foregone production in the three states as a result of well closures in 1977 and shorter well lives as a result of higher operating costs. The foregone production is 1.8% of the projected remaining lifetime production of the impacted wells, assuming a 12% decline rate and current price regulations. The total is 0.2% of 1975 API proven reserve estimates for the three states.
- The average increase in production costs for the three states would be $.34 per barrel of affected oil as a result of the reinjection requirement. Operating costs would increase by about $.06 per barrel.

II. CHARACTERIZATION OF THE ONSHORE OIL EXTRACTION INDUSTRY

1. 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-1 lists the components of U.S. energy demand for 1970, 1972, 1974, 1975 and 1976. Oil was the primary source of 46.5% of energy consumed in 1976. Natural gas accounted for 27%. 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 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.

TABLE II-1

U.S. ENERGY DEMAND BY PRIMARY SOURCE - 1970-72, 1974, 1975, 1976

Energy Form	1976	1975	1974	1972	1970
Oil (quadrillion Btu/yr)	34.4 (46.5%)	32.8	33.5	32.8	29.6 (44.1%)
Gas	20. (27%)	20.6	22.2	23.3	22. (32.7%)
Coal	13.8 (18%)	13.2	13.2	12.5	12.7 (18.9%)
Nuclear	2.6 (3.5%)	1.8	1.2	.6	.2 (.3%)
Hydro	3.2 (4.3%)	3.1	3.1	2.9	2.7 (4%)
Total	74.0	71.5	73.1	72.1	67.2

SOURCE: Oil and Gas Journal, January 26, 1976

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. Table II-2 indicates the historical supply/demand pattern in the United States for crude oil.

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

TABLE II-2

SUPPLY/DEMAND OF CRUDE OIL

('000 barrel/day)

	1976[a]	1975	1974	1973	1972
Supply					
Crude Imports	5,235	4,133	3,477	3,244	2,222
Crude Production	8,085	8,343	8,764	9,208	9,477
	13,320	12,476	12,241	12,452	11,699
Demand					
Crude Refinery Runs] Crude Transfers, Losses]	13,209	12,465	12,161	12,463	11,756
Crude Exports	3	6	2	2	1
Total	13,212	12,471	12,163	12,465	11,757
Stock Charges	-86	+5	+78	-13	-58

SOURCE: *Oil and Gas Journal*, January 26, 1976; July 26, 1976 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.

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-3 lists the estimated U.S. energy demand by form, with imported oil reported separately. The base case assumed that government

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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-3

U.S. ENERGY DEMAND BY PRIMARY SOURCE - 1985

(Quadrillion Btu's)

Energy Form	1972	1985			
		$7 Oil		$11 Oil	
		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

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 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-3 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-4 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-5 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-6 lists the estimated gas production assuming the $11 per barrel world oil price and accelerated development. The report saw very 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.

TABLE II-4

U.S. CRUDE OIL PRODUCTION - 1974 TO 1985

(million barrels per day)

"Business as Usual" Case

World Price ($/bbl)	1974	1977	1980	1985
4	10.5	9.0	9.8	9.8
7	10.5	9.5	11.1	11.9
11	10.5	9.9	12.2	15.0
"Accelerated Development" Case				
4	10.5	9.7	11.1	11.[illegible]
7	10.5	10.2	12.9	16.6
11	10.5	10.3	13.5	2[illegible]

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

TABLE II-5

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-6

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

To illustrate the role of imports in the relationship between U.S. oil supply and demand, Figure II-1 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 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.

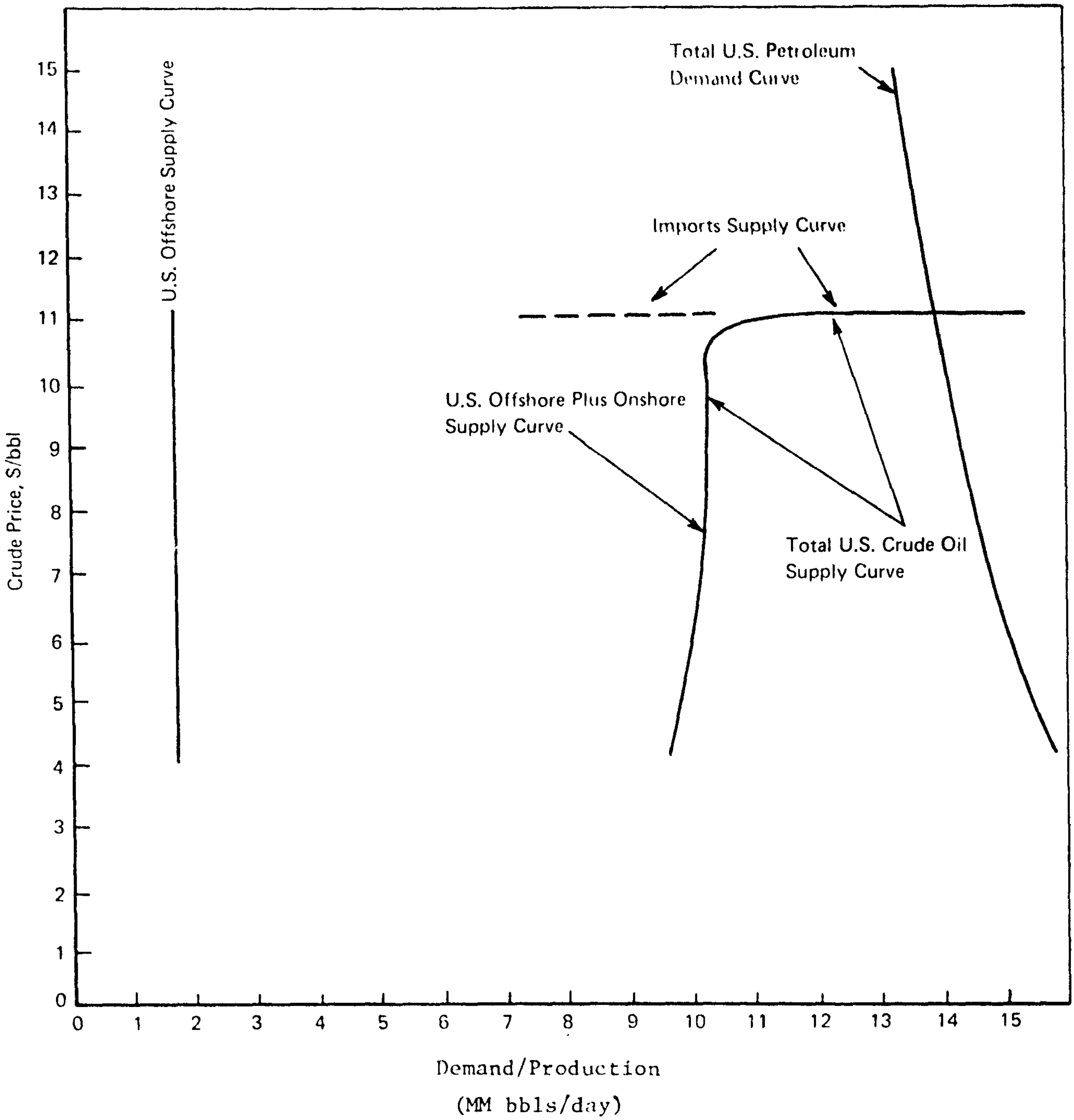

FIGURE II-1 1977 U.S. PETROLEUM SUPPLY AND DEMAND FUNCTIONS
(Accelerated Development Scenario)

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

2. Characteristics of the Onshore Oil and Gas Producing Companies

The oil and gas industry can be divided into two categories -- onshore and offshore operations, the former predominating. In 1972 the onshore operations consisted of 5,530 operating companies employing 111,300 workers. Total production was 2,647.6 million barrels from 340,148 oil wells, and 17,488.2 billion cubic feet of gas from 83,985 wells. The value of this production was $12,896.1 million. Expenses for supplies were $4,268.3 million, and payrolls amounted to $1,305.7 million. Capital expenditures totaled $2,171.9 million, of which $1,232.4 million went into mineral development and exploration.

The onshore industry has been and continues to be concentrated in a few large fully-integrated companies that exert control from production through distribution. The reasons for this dominance come from their control of transportation and market sources, plus their ability to afford both the large capital expenditures and risks necessary for exploration. Tables II-7 and II-8 indicate the extent of this concentration.

On the other end of the spectrum are the small producers. Table II-9 shows their share of the industry, in which 75% of the operations account for less than 2% of the value of shipments. Interestingly, their share of the volumes produced is significantly less than their share of the value.

TABLE II-7

COMPARISON OF PARTICIPATION IN VARIOUS ASPECTS OF THE PETROLEUM INDUSTRY FOR THE NINE LARGEST OIL COMPANIES

Company	% of U.S. Total		
	Production	Refining	Product Sales
Exxon	11.9	8.6	10.6
Texaco	9.7	8.2	8.3
Shell	7.8	8.0	6.5
Amoco	6.0	7.6	6.6
Socal	5.7	7.3	6.4
Mobil	4.8	6.8	6.1
Gulf	6.9	6.3	4.9
Arco	5.4	5.6	4.7
Sun	2.9	3.4	3.5
Total, 9 companies	61.1	61.8	57.6

SOURCE: Market Performance and Competition in the Petroleum Industry, Part 1, Committee on Interior and Insular Affairs, Washington, D.C., 1974, p. 102

TABLE II-8

MARKET SHARE OF EIGHT LARGEST PRODUCERS

Eight Largest Producers*		% of Total
Value of shipments + receipts ($ mil.)	8,256.7	53%
Crude petroleum: value	6,187.6	57%
quantity (mil. bbls.)	1,816.0	56%
Natural gas: value	2,059.3	50%
quantity (bil. cu. ft.)	10,595.7	50%
Employment (000)	22.6	19%
Capital expenditure	1,300.6	44%

*5,530 total producers

SOURCE: 1972 Census of Mineral Industries, p. 13A-61.

TABLE II-9

MARKET SHARE OF SMALLEST PRODUCERS

4,130 Smallest Producers*		% of Total
Value of shipments + receipts ($ mil.)	274.1	1.7%
Crude petroleum: value	525	.5%
quantity (mil. bbls.)	16.5	.5%
Natural gas: value	12.2	.3%
quantity (bil. cu. ft.)	68.1	.3%
Employment (000)	6.2	5.0%
Capital expenditure	43.9	1.5%

*5,530 total producers

SOURCE: 1972 Census of Mineral Industries, p.13A-62.

3. 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.

The Congress enacted a new set of oil price regulations in December 1975 which established a two-tier pricing system for domestically-produced oil. As written, the regulations will be in effect through May 1979. 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 now priced at a higher tier price, 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.

All offshore and onshore production to which the effluent guidelines would apply are now price controlled. Deregulation would increase these prices to near 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 crude oil prices are deregulated and there is a specified level of world crude prices. 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 21 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) under the Emergency Petroleum Allocation Act (December 1973),which imposed regulations on crude prices. In December 1975, the Congress enacted the Environmental Policy and Conservation Act (EPCA), which revised the price control regulations and established a two-tiered system of prices for domestically-produced crude.

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-10 lists representative posted and actual prices.

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

TABLE II-10

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 over-production situation), partly to prevent long-range dependence on foreign oil, and partly to use as a level 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. Even though the production costs of most domestic oil is far below the price of imported oil, production cannot meet demand. Table II-11 lists historical crude prices from various domestic and foreign producing areas.

The cost of crude includes a wellhead price plus tariffs, plus cost of delivery to a refinery. Tables II-12 and II-13 list crude price and transportation costs to U.S. refining areas from several producing areas. Table II-12 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-13 compares U.S. new oil with minimum foreign oil prices. One sees in the table that the price of the new oil has risen to just below the same price as the foreign oil when transportation costs are taken into consideration.

U.S. Crude Petroleum Price Regulations

Under the Emergency Petroleum Allocation Act there was a domestic crude price control program with two levels. "Old" oil (a volume equivalent to the average daily production from a particular property during the year 1972 less volumes, if any, of "released" oil produced) had a ceiling price of its May 15, 1973 posting plus $1.35 per barrel. According to FEA figures, the weighted average "old" oil price that emerged from these guidelines was $5.25/barrel.

TABLE II-11

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°)**	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

TABLE II-12

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-13

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

"New" oil, or the production in excess of the daily average during 1972, as well as "released" oil, or an amount of "old" oil from a property equivalent to the production of "new" oil from that property, was not subject to ceiling prices and could theoretically rise to import parity. Production from stripper wells, that is wells yielding less than 10 barrels per day, was also exempt from price controls. Imported crude remained free of price controls, although it was subject to the import duties and license fees.

Curiously enough, what had been designed as a two-tier system of crude prices, with an "old" controlled price and all other crude at import parity, did not work out so neatly in practice. In reality there were three price levels -- "old", "new", and foreign. The average "new" crude price was typically about \$1.00 to \$1.50 per barrel below the average price of imported crude. One of the principal reasons that "new" oil prices did not rise to import parity may have been the existence of state regulations known as "equal purchaser laws" in many of the oil-producing states. These laws refer to a purchaser's right to offer fundamentally different prices to different crude producers in a state for the same quality crude. Such laws were originally enacted to protect independent producers in their transactions with majors, but were interpreted to apply to "old" and "new" oil prices when these classifications were created.

The text of the EPCA was not explicit as to the actual mechanics of domestic crude price controls and specified only that a system be devised by February 1976 which resulted in an average controlled domestic crude price of \$7.66 per barrel. Using its rule-making powers, the FEA instigated a price control program which achieved an average domestic ceiling of \$7.66 per barrel by having a two-tier crude pricing system. "Old" oil became lower tier oil and prices were held at the previous controlled levels (giving an average "old" oil price of $5.25 per barrel). "New" oil and stripper well production became upper tier oil which was priced at its September 30, 1975 posting less $1.32 per barrel. The resultant average upper tier price was $11.28 per barrel. The concept of "released" oil was eliminated. The weighted average of lower tier and upper tier production was designed to give the required national average of $7.66 per barrel.

In the process of devising the new two-tier domestic crude pricing structure, the FEA specified some important changes in the definitions of old and new. Lower tier oil is essentially "old" oil, but the base period control level used in defining "old" has been changed. Instead of being a volume of production equal to the production level for a similar period in 1972, lower tier oil is defined as either crude production equivalent to the daily average "old" oil production in 1975 or production equivalent to the daily average crude production in 1972. However, the base period production levels will be subject to semi-annual review beginning in July, 1976. If a property produced no upper tier oil in the six months preceding the semi-annual review, then its base period production level is eligible for revision. The FEA can make a downward revision in the property's base period production level equal to three-quarters of the average annual rate of decline between 1972 and 1975 (1972 production minus 1975 production divided by 3). This new definition of the base period gives producers whose "old" oil production had been declining an opportunity to regain the losses in their base period production levels experienced in 1973 through 1975 and also to retain a possibility of crossing the upper tier threshold despite declining production. In the current pricing regulations there is also a cumulative deficiency clause which stipulates that producers may not sell any crude as upper tier oil until the average daily production since February 1, 1976 exceeds the base period control level. In general, it is hoped that the revised regulations will provide strong incentives for producers to maintain and maximize their production levels.

According to the provision of EPCA, the average domestic crude price (i.e., the initial $7.66 composite price for lower and upper tier oil) will be allowed to increase by a rate not to exceed 10% on an annual basis. In the EPCA legislation it is stated that the 10% maximum is to be comprised of an inflation factor not to exceed 7% per annum and a production incentive of 3%. The 10% ceiling will be the subject of some further FEA consideration regarding whether or not this ceiling will act to suppress potential domestic production.

The price increases were designed to compensate producers for the effects of inflation and also to provide an incentive to expand production levels. In its implementation of the EPCA provisions for price increases, FEA has decided to apply the increases (at least in the initial year or so) equally to upper and lower tier production. In later years FEA anticipates that it may weight the allowable increases in favor of upper tier production to assure the maintenance of adequate incentives to sustain and expand upper tier production levels. Table II-14 shows the FEA's initial schedule for monthly increases in the average lower and upper tier crude prices. FEA plans to review the schedule of increases on at least a semi-annual basis in order to adjust for unanticipated distortions in the composite average price caused by changes in the mix of upper and lower tier oil production or in the average price of upper or lower tier crude.

TABLE II-14

FEA PROJECTIONS OF CEILING PRICES * FOR LOWER AND UPPER TIER OIL PRODUCTION
February 1976 - May 1979
($/Bbl)

Month	Lower Tier 5/15/73 posting plus:	Estimated Lower Tier Price	Upper Tier 9/30/75 posting less:	Estimated Upper Tier Price
2/76	$1.35	$5.25	$1.32	$11.28
3/76	1.38	5.28	1.25	11.35
4/76	1.41	5.31	1.18	11.42
5/76	1.45	5.35	1.11	11.49
6/76	1.48	5.38	1.05	11.55
7/76	1.51	5.41	0.97	11.63
8/76	1.54	5.44	0.90	11.70
9/76	1.58	5.48	0.83	11.77
10/76	1.61	5.51	0.76	11.84
11/76	1.64	5.54	0.69	11.91
12/76	1.68	5.58	0.62	11.98
1/77	1.71	5.61	0.55	12.05
2/77	1.74	5.64	0.47	12.13
3/77	1.77	5.67	0.41	12.19
4/77	1.80	5.70	0.34	12.26
5/77	1.83	5.73	0.28	12.32
6/77	1.87	5.77	0.21	12.39
7/77	1.89	5.79	0.15	12.45
8/77	1.93	5.83	0.08	12.52
9/77	1.96	5.86	0.01	12.59
Effective 10/77 Upper Tier price calculations change			9/30/75 posting,	
10/77	1.99	5.89	0.05	12.65
11/77	2.02	5.92	0.12	12.72
12/77	2.05	5.95	0.19	12.79
1/78	2.08	5.98	0.26	12.86
2/78	2.12	6.02	0.23	12.83
3/78	2.14	6.04	0.38	12.98
4/78	2.16	6.06	0.43	13.03
5/78	2.19	6.09	0.48	13.08
6/78	2.19	6.09	0.55	13.15
7/78	2.19	6.09	0.62	13.22
8/78	2.20	6.10	0.70	13.30
9/78	2.21	6.11	0.77	13.37
10/78	2.21	6.11	0.84	13.44
11/78	2.22	6.12	0.92	13.52
12/78	2.22	6.12	0.99	13.59
1/79	2.23	6.13	1.07	13.67
2/79	2.23	6.13	1.14	13.74
3/79	2.25	6.15	1.22	13.82
4/79	2.26	6.16	1.29	13.89
5/79	2.26	6.16	1.35	13.95
End of Program prices: $6.16				$13.95

* Based on 4th quarter 1975 deflator. Price will be subject to revision as more current deflators are available

It is not the intent of this analysis to make a projection of world or U.S. crude oil prices over the period of the analysis -- about 20 years. There are strong economic and political forces with opposing views on what United States crude pricing policy should be. There is, in addition, a wide range of speculation on Middle Eastern oil pricing over a 10 to 20 year period.

For the purposes of this analysis, the current two-tiered domestic price system is assumed to stay in effect through the study period. Costs and prices are held at 1975 levels. The 3% yearly increase in real crude prices (in excess of inflation) allowed by the EPCA has been incorporated in the computation of yearly revenues from production. The price schedule shown in Table 14 has been extended beyond the current expiration of the regulations.

4. Financial Characteristics

The Role of Financial Characteristics in the Economic Impact Analysis

The onshore oil and gas industry has several unique financial characteristics which reflect the risks of the business, its special tax status, and its cash flow patterns. Three issues are particularly relevant to this economic impact analysis:

- 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?

The following sections of this chapter address these issues.

In contrast to the offshore oil industry, the onshore oil industry is characterized by the presence of both major oil companies and small independent producers. These small independents account for about 50% of domestic onshore production. Furthermore, in 1971 and 1973, the lower quartile of these smaller companies showed operating losses. Thus, the impact of the capital costs for pollution control equipment may be more significant for the smaller operators. The special characteristics of the smaller companies will be discussed separately.

Capital Investment and Capital Availability

According to the latest analysis published by the Chase Manhattan Bank, the petroleum industry will need to invest about $480 billion in exploration and production during the next ten years. Another $475 billion will be required for additional transportation, marketing, and processing facilities. This total investment of $955 billion is nearly four times more than actual expenditures during the past four years. This amount does not include provision for repayment of debt, expansion of working capital, or payment of dividends.

Another study of the oil and gas industry's capital needs, performed by Bankers Trust Company, estimates that the total capital requirements of the industry will be about $300 billion, in constant 1974 dollars, between 1975 and 1990 (see Table II-15). Nearly 75% of this amount is required for exploration and development alone. Whether or not the U.S. financial markets can supply these capital funds continues to be an important subject of discussion.

One of the principal determinants of the industry's level of investment and access to capital is its profitability. Historically, from 1952 to 1972 the industry's profits were low and capital investment was inadequate. In 1973 and 1974, both profits and capital investment improved dramatically. In fact, 1974 investment increased 46% over 1973. Although profits declined in 1975, the level of capital spending has continued at its high level. The industry apparently is borrowing heavily and drawing down working capital to sustain this rate of spending.

About 45% of the industry's capital outlay in 1974 was devoted to production. Moreover, the U.S. accounted for about 60% of the worldwide investment in exploration and development and nearly 60% of the increase in investment (see Table II-16). However, about half of these expenditures in the U.S. were for lease bonuses.

TABLE II-15

CAPITAL NEEDS OF THE OIL AND GAS INDUSTRY, 1975-1990

(millions of 1974 dollars)

Exploration and development	220,727
Refining	35,250
Tankers	6,377
Pipelines	25,101
Deepwater ports	1,500
Marketing	9,600
Total	298,555

SOURCE: Oil and Gas Journal, February 2, 1976.

TABLE II-16

GEOGRAPHICAL BREAKDOWN OF CAPITAL EXPENDITURES

	1974	1973	Change	
	Million Dollars		Mill $	Percent
United States	11,450	7,440	+4,010	+53 9
Canada	1,300	1,075	+ 225	+20 9
Venezuela	305	205	+ 100	+48 8
Other Western Hemisphere	975	625	+ 350	+56 0
Western Hemisphere	14,030	9,345	+4,685	+50 1
Western Europe	2,415	1,325	+1,090	+82 3
Africa	890	625	+ 265	+42 4
Middle East	1,000	855	+ 145	+17 0
Far East	1 200	775	+ 425	+54 8
Eastern Hemisphere	5,505	3,580	+1,925	+53 8
Total	19,535	12,925	+6,610	+51 1

SOURCE: "Capital Investments of the World Petroleum Industry," 1974, Chase Manhattan Bank

The Chase study also includes an analysis of the capital investments of the world petroleum industry. The most recent year for which data is available is 1974. Table II-17 lists capital expenditures for the world and the U.S. from 1968 to 1974. Table II-18 is a breakdown of exploration and development expenditures in the U.S. for 1974 and 1973. In the Chase analysis, expenditures for lease rentals and geological and geophysical expense are not capitalized. This pattern may not always hold true, particularly for dry holes and geological and geophysical expenses.

The Oil and Gas Journal also collects statistics on capital expenditures each year from 150 firms. These statistics are proportionately projected to the whole industry on the basis of the companies' share of total industry crude production. Table II-19 lists the results for 1973-1975, with projections for 1976. 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.

Comparing the Chase study with the Oil and Gas Journal analysis, it is evident that the estimates for expenditures are significantly different for the exploration and production categories. However, they do give general guidance as to the order of magnitude of expenditures that one should use as a point of comparison with the pollution control capital expenditures. Table II-20 lists the general comparison values which can be used in the impact analysis.

The Chase Manhattan Bank studies of major oil companies compile information on the sources and uses of funds. Table II-21 contains the sources of cash for 1974 and 1973. In 1974, the cash flow from capital recovery mechanisms such as depletion and depreciation dropped to 35% of the

TABLE II-17

ESTIMATED CAPITAL AND EXPLORATION EXPENDITURES

	1968	1969	1970	1971	1972	1973	1974
	Million Dollars						
WORLD							
Crude Oil and Natural Gas	6,875	7,075	6,650	6,520	9,590	12,415	18,765
Natural Gas Liquids Plants	585	465	530	685	515	[illegible]	770
Pipe Lines	[illegible]	910	950	[illegible]	1,230	[illegible]	[illegible]
Tankers	1,650	2,050	2,575	2,675	3,775	[illegible]	[illegible]
Refineries	2,950	3,210	4,000	4,755	4,955	4,865	[illegible]
Chemical Plants	1,480	1,310	1,525	1,535	1,350	[illegible]	[illegible]
Marketing	2,655	2,305	3,220	3,380	2,825	2,460	2,215
Other	615	550	720	840	710	[illegible]	875
Total Capital Expenditures	17,900	18,375	20,125	21,800	24,950	[illegible]	[illegible]
Geological & Geophysical Expense and Lease Rentals	1,330	1,380	1,340	1,395	1,540	1,700	[illegible]
COMBINED	19,230	19,755	21,465	23,195	26,490	[illegible]	45,885
UNITED STATES							
Crude Oil and Natural Gas	4,675	4,525	4,110	3,185	[illegible]	[illegible]	[illegible]
Natural Gas Liquids Plants	250	225	225	200	[illegible]	[illegible]	225
Pipe Lines	425	300	450	550	[illegible]	[illegible]	[illegible]
Tankers	50	100	100	125	[illegible]	[illegible]	[illegible]
Refineries	800	950	1,075	1,050	[illegible]	[illegible]	[illegible]
Chemical Plants	650	575	550	500	450	425	825
Marketing	1,150	1,250	1,450	1,350	1,100	[illegible]	[illegible]
Other	350	250	265	290	260	325	[illegible]
Total Capital Expenditures	8,350	[illegible]	8,225	[illegible]	9,050	[illegible]	[illegible]
Geological & Geophysical Expense and Lease Rentals	715	[illegible]	665	715	740	[illegible]	[illegible]
COMBINED	9,065	8,900	8,890	7,965	9,790	[illegible]	[illegible]

SOURCE: "Capital Investments of the World Petroleum Industry, 1974," Chase Manhattan Bank.

TABLE II-18

EXPLORATION AND DEVELOPMENT EXPENDITURES

IN THE U.S.: 1973 AND 1974

	1973 ($ million)	1974 ($ million)
Expenditure		
Lease acquisition		
Onshore	500	700
Offshore	3,100	5,100
Producing wells	2,705	3,975
Dry holes	985	1,450
Geological and geophysical expense	675	925
Lease rentals	175	205
Total	8,140	12,355

SOURCE: "Capital Investments in the World Petroleum Industry, 1974," Chase Manhattan Bank

TABLE II-19

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

(1973-1976)

	1976 (budgeted) ($ million)	1975 (estimated) ($ million)	1974 ($ million)	1973 ($ million)
Exploration and Production				
Drilling and Exploration	8,485.0	8,347.0	7,329.0	6,660.8
Production	6,670.0	4,372.0	2,135.0	1,734.8
OCS lease bonus	1,250.0	1,087.0	5,024.0	3,082.0
Total	16,405	13,806.0	14,488.0	11,477.6
Other Expenditures				
Refining	1,760.0	2,724.0	2,446.0	1,103.8
Petrochemicals	2,282.0	4,266.0	810.0	269.1
Marketing	830.0	834.0	679.0	914.5
Crude Products Pipelines	2,559.0	2,675.0	1,096.0	150.0
Natural Gas Pipelines	490.0	564.0	541.0	600.0
Other Transportation	230.0	188.0	163.0	152.9
Miscellaneous	1,946.0	1,364.0	1,278.0	646.9
Total	10,097.0	12,615.0	7,013.0	3,837.2
Total Expenditures	26,502.0	26,421.0	21,501.0	15,314.8

SOURCE: *Oil and Gas Journal*, February 23, 1976.

TABLE II-20

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

Offshore Oil and Gas Production	$6-8 billion per year
Onshore Oil and Gas Production	$3-5 billion per year
Other Capital Expenditures (refineries, pipelines, marketing, etc.)	$6-8 billion per year
Total	$15-21 billion per year

SOURCE: Arthur D. Little, Inc., estimates

TABLE II-21

CASH FLOW OF CHASE GROUP

	1974 ($ millions)		1973 ($ millions)	
Net Income	16,371	(57%)	11,678	(55%)
Write-offs (including depreciation and depletion)	10,133	(35%)	8,345	(39%)
Other non-cash charges (net)	2,332	(8%)	1,207	(6%)
TOTAL	28,836		21,230	

SOURCE: "Financial Analysis of a Group of Petroleum Companies," 1973 and 1974, Chase Manhattan Bank total cash flow from 39% in 1973. Table II-22 lists all of the sources and uses of working capital for the Chase Group in 1974. The percentage of funds available from cash earnings was slightly lower in 1974 (72.8%) than it was in 1973 (73.4%). Long-term debt accounted for a slightly higher percentage of funds in 1974 (15.9%) than in 1973 (15.2%). Perhaps the most important fact is that total funds available in 1974 were $39.6 billion, an increase of 37% over 1973. In 1974, 57.8% of the available funds were used for capital expenditures whereas only 50.6% were used for this purpose in 1973. Dividend payments to shareholders dropped to 11.5% of total available funds, from 13.7% in 1973.

Profitability

Due to large price increases for crude oil dictated by the governments of some foreign producing countries, there were significant changes in the income statements of the Chase Group of companies. Gross revenue increased 83% over 1974, while record revenue levels were recorded in all product categories (see Table II-23). In spite of this increase, operating costs increased by an even larger percentage, 94%. Net income also grew, but not by as large a percentage as revenue or expenses. Earnings increased by about 40% over 1973. Important factors in this gain were inventory profits early in the year and improved contributions from chemical operations. The pattern of earnings growth dwindled as the year progressed and became a decline of 12% by the fourth quarter. One of the most significant changes was the increase in estimated income taxes. They were 117.5% higher in 1974 than in 1973. The Group's rate of return on revenue dropped to 6.7% in 1974, compared to 8.7% in 1973, 6.5% in 1972, and 7.4% in 1971. The

TABLE II-22

SOURCES AND USES OF WORKING CAPITAL, 1974

	Million Dollars	Percent Distribution
Funds Available From:		
Cash Earnings	28,836	72.8
Long-Term Debt Issued	6,275	15.9
Preferred and Common Stock Issued	119	0.3
Sales of Assets and Other Transactions	4,372	11.0
TOTAL	39,602	100.0
Funds Used For:		
Capital Expenditures	22,902	57.8
Investments and Advances	914	2.3
Dividends to Companies' Shareholders	4,562	11.5
Dividends to Minority Interests	210	0.6
Long-Term Debt Repaid	4,124	10.4
Preferred and Common Stock Retired	102	0.3
TOTAL	32,814	82.9
Change in Working Capital	+6,788	17.1

SOURCE: "Financial Analysis of a Group of Petroleum Companies," 1974, Chase Manhattan Bank

TABLE II-23

INCOME STATEMENT OF THE CHASE GROUP

	1974	1973	Percent Change
	Million Dollars		
Gross Operating Revenue	239,502	130,948	+ 82.9
Non-Operating Revenue	5,033	2,961	+ 70.0
Total Revenue	244,535	133,909	+ 82.6
Operating Costs and Expenses	175,188	90,298	+ 94.0
Taxes – Other than Income Taxes (a)	7,214	6,241	+ 15.6
Write-offs	10,133	8,345	+ 21.4
Interest Expense	2,478	2,008	+ 23.4
Other Charges	15	37	– 59.5
Total Deductions	195,028	106,929	+ 82.4
Net Income before Income Taxes	49,507	26,980	+ 83.5
Estimated Income Taxes	32,379	14,889	117.5
Income Applicable to Minority Interests	757	413	83.3
Net Income (b)	16,371(c)	11,678	40.2

(a) Excludes $27,113 million in 1974 and $25,785 million in 1973 representing sales and excise taxes on gasoline and other refined products, which are collected from customers and accounted for to United States federal, state and city authorities, and to other governments Such taxes are deducted before arriving at gross operating revenue

(b) Includes earnings from operations outside U.S.: 1974 $9,970 million and 1973 $7,544 million.

(c) Excludes $112 million of extraordinary income

SOURCE: "Financial Analysis of a Group of Petroleum Companies," 1974, Chase Manhattan Bank

proportion of earnings attributed to U.S. operations increased slightly, to 39%, from 35% in 1973. This represents a continued sharp decline from the levels reached in 1972 and 1971 (about 50%).

Earnings of the Chase Group in 1975 confirm the suspicion that the record levels of 1974 were a one-time thing, brought about by external events. In 1975, the Groups earnings declined by 29%.

Issues Affecting Capital Investment and Profitability

Two important political issues, "windfall" profits tax and divestiture of integrated oil companies, are presently being debated by the Congress. The resolution of these issues can potentially have a serious impact on the profitability, level of capital investment, and access to capital of the industry.

Of these two issues, the question of divestiture is receiving the most attention by the Federal government and the press at the present time. Two approaches have been taken to this issue. After recent investigations into the oil industry, the Federal Trade Commission has issued an antitrust complaint against the eight largest oil companies with marketing operations on both the East Coast and the Gulf Coast. In addition, several bills have been introduced in Congress to separate the major oil companies into independent, functional, operating companies. The stated purpose of both of these approaches is to eliminate monopolistic practices and increase competition in the petroleum industry.

There has been a significant reaction to the divestiture plans, especially the proposed legislation, from both government, industry, and the financial community. Much of this reaction is negative. A study recently concluded by the U.S. Treasury Department states that "divestiture would be contrary to U.S. national interests and would handicap the achievement of our national energy goals. It is likely that divestiture would create upward pressure on domestic prices and cause domestic energy investment to decrease."

A number of industry analysts believe that the long-term financial effects of divestiture would be particularly severe. They cite several reasons that support this belief. Historically, the integrated oil companies have exhibited more stable case flow levels than the smaller independents. This stability of cash flow, together with other factors such as debt-to-equity ratio, company size, and debt coverage ratios, are significant factors in determining a company's bond ratings, and thus, its cost of debt. Forced divestiture would threaten the stability of this cash flow, causing bond ratings to fall and the cost of debt to increase. Given the level of uncertainty due to potential litigation over various issues, it is also highly likely that companies' ability to raise new equity capital would be dampened. Thus, a principal effect would probably be an increase in the cost of capital for the petroleum companies. Because of this increase in the cost of capital and a lower capacity to raise sufficient funds in the external capital markets, the long-run level of capital investment would probably be reduced.

In addition to windfall profits, taxes and divestiture, other serious issues facing the oil industry include the government's policies on oil prices and oil imports. It is difficult at this time to assess fully or predict the impact of all of these issues on the industry's ability to raise capital. The principal effect at this time is that the industry's environment is characterized by considerable uncertainty.

Capital Structure

For the onshore oil and gas industry, two classes of producers are important: larger, major companies and smaller independent producers. This analysis will discuss these two categories separately.

The petroleum industry has historically depended on internally-generated funds as its primary source of capital. The sample balance sheet for the Chase Group of companies is contained in Table II-24. Long-term debt plus deferred credits and minority interests made up about 19.2% of total capitalization. The ratio of debt to equity was about 40%, the same as in 1973. If long-term lease arrangements had been capitalized, long-term debt would be 31% of total capital employed. In 1974, the ratio of current assets to current liabilities - the current ratio - dropped to 1.4, the lowest it has ever been.

TABLE II-24

BALANCE SHEET OF THE CHASE GROUP

	12/31/74 ($ Million)	%	12/31/73 ($ Million)	%
ASSETS				
Current Assets	86,889	45.0	56,149	37.3
Investments and Advances	10,628	5.5	10,386	6.9
Property, Plant and Equipment (a)	91,169	47.2	79,613	52.9
Other Assets	4,561	2.3	4,268	2.9
Total Assets	193,247	100.0	150,416	100.0
LIABILITIES AND NET WORTH				
Current Liabilities	60,454	31.3	36,502	24.2
Long-Term Debt	25,591	13.2	22,727	15.1
Deferred Credits	7,591	3.9	5,711	3.8
Other Reserves	3,803	2.0	2,821	1.9
Minority Interests	4,068	2.1	3,274	2.2
Net Worth:				
Preferred Stock	335	0.2	315	0.2
Common Stock	11,536	6.0	10,455	7.0
Capital Surplus	8,773	4.5	8,597	5.7
Earnings Reinvested in Business	71,096	36.8	60,014	39.9
Shareholders' Equity	91,740	47.5	79,381	52.8
Total Liabilities and Net Worth	193,247	100.0	150,416	100.0

(a) After deducting accumulated reserves of $69,219 million in 1974 and $64,060 million in 1973.

SOURCE: "Financial Analysis of a Group of Petroleum Companies," 1974, Chase Manhattan Bank

Cost of Capital for Larger, Major Companies

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-25 , preferred stock does not represent a very high proportion of the capital structure of the leading producers. Thus, for the purposes of this analysis, the weighted average cost of capital will consist

TABLE II-25

PETROLEUM INDUSTRY CAPITALIZATION, 1975

Firm	Total Long-Term(1) Capital ($ Million)	Debt (%)	Preferred (%)	Common Equity Net Worth (%)
Amerada Hess	2,359	27	29	44
Apache Corp.	127	43.5	0.5	56
Apco Oil	131	51	0	49
Ashland Oil	1,448	35	15	50
Atlantic Richfield	6,236	26	15	59
Belco Petroleum	234	26	0	74
British Petroleum	8,834	38.5	0.3	61.2
Buttes Gas and Oil	191	65	1	34
Charter Company	384	52	11	37
Cities Service	2,412	32	0	68
Clark Oil & Refining	190	47	0	53
Commonwealth Oil	360	49	7	44
Continental Oil	3,040	30	0	70
Dome Petroleum	440	58.5	0	41.5
Exxon	20,476	17	0	83
Getty Oil	2,108	8.5	1.2	90.3
Gulf Oil	7,752	17	0	83
Gulf Oil Canada	1,147	10	0	90
Husky Oil	303	33	3	64
Imperial Oil	1,920	18	0	82
Kerr-McGee	1,024	21	0	79
Kewanee Industries	273	33	0	67
Louisiana Land Exploration	504	32	0	68
Marathon Oil	1,261	20	0	80
Mobil Oil Corp.	8,675	21	0	79
Murphy Oil	571	40.3	0.2	59.5
Natomas Company	369	40	0	60
Occidental Petroleum	2, 62	39	19	42
Pacific Petroleums	479	26	0	74
Pennzoil	1,472	55	6	39
Phillips Petroleum	3,317	27	0	73
Quaker State Oil	160	21	0	79
Reserve Oil & Gas	137	15	5	80
Royal Dutch Petroleum	15,574	25	0	75
Shell Oil	5,112	23.5	0	76.5
Skelly Oil	807	12	0	88
Standard Oil (Cal.)	7,832	17	0	83
Standard Oil (Ind.)	7,294	23	0	77
Standard Oil (Ohio)	3,422	57	0.3	42.7
Sun Oil	3,894	17	22	61
Superior Oil	639	15	0	85
Tesoro Petroleum	543	40	19	41
Texaco	10,909	20	0	80
Total Petroleum	162	20	15	65
Union Oil of California	3,066	24	13	63
United Refining	67	34	0	66

(1) Includes long-term debt, preferred stock and common stock net worth.

SOURCE: Balance Sheets as of December 31, 1975.

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.

In determining the weighting of debt and equity for the weighted average cost of capital, the book values of long-term debt and the net worth of stockholders' equity as of December 31, 1975, were employed. The market value of debt is not easily determined for most corporations. This approach does not significantly affect the estimate of the weighted average cost of capital.

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.

The tax rate does vary significantly between firms. Thus, in estimating the cost of debt, the effective tax rate for the year 1975 has been used as the marginal tax rate.

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 are to buy 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 revenues 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. The 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 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 averaging 6.05% over this period. 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 averaging 13.2% from 1971 to 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 long-term capital and total revenues. The arithmetic mean was also calculated. The estimated industry cost of capital ranges from a low of 10.3% (weighted by long-term capital) to a high of 10.6% (weighted by total revenue), with an average of 10.5%. (See Table II-26 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 11% seems reasonable.

Several words of caution about the cost of capital for an industry should be added at this point. Although 11% 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 7.8% to 12.8%. Rather than saying that the cost of capital of the industry is about 11%, it may be more appropriate to state that the cost of capital in the industry ranges from 7.8% to 12.8%.

Furthermore, interest rates and stock prices have fluctuated widely in the past 36 months. As shown in Table II-27, common shares of many of the 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

TABLE II-26

CALCULATION OF COST OF CAPITAL[1]

Firm	Average[2] Beta	Tax Rate[2] (%)	Cost of[3] Equity (%)	Cost of[3] Capital (%)
Amerada Hess	1.05	60	13.6	9.9
Apache Corp.	1.10	38	13.9	10.3
Apco Oil	.90	--	12.5	11.0
Ashland Oil	.95	51	12.9	9.5
Atlantic Richfield	.90	61	12.5	9.9
Belco Petroleum	1.05	37	13.6	11.6
British Petroleum	.75	90	11.4	9.3
Buttes Gas and Oil	1.25	50	15.0	8.3
Charter Company	1.25	70	15.0	7.8
Cities Service	.85	41	12.1	10.0
Clark Oil & Refining	1.30	--	15.4	12.6
Commonwealth Oil	1.10	--	13.9	11.6
Continental Oil	1.00	64	13.2	10.3
Dome Petroleum	1.10	37	13.9	9.3
Exxon	.90	74	12.5	10.9
Getty Oil	.85	62	12.1	11.4
Gulf Oil	.90	74	12.5	10.8
Gulf Oil Canada	.75	45	11.4	10.8
Husky Oil	.85	47	12.1	9.7
Imperial Oil	.90	49	12.5	11.1
Kerr-McGee	1.00	41	13.2	11.6
Kewanee Industries	1.30	47	15.4	12.0
Louisiana Land Exploration	1.15	46	14.3	11.4
Marathon Oil	.85	73	12.1	10.2
Mobil Oil Corp.	.95	75	12.9	10.7
Murphy Oil	1.30	61	15.4	10.7
Natomas Company	1.10	76	13.9	9.3
Occidental Petroleum	1.05	74	13.6	8.3
Pacific Petroleums	1.10	43	13.9	11.7
Pennzoil	1.30	30	15.4	10.2
Phillips Petroleum	1.10	55	13.9	11.3
Quaker State Oil	1.15	49	14.3	12.3
Reserve Oil & Gas	1.15	48	14.3	12.8
Royal Dutch Petroleum	0.70	70	11.1	9.0
Shell Oil	0.95	42	12.9	11.2
Skelly Oil	0.50	47	9.6	9.1
Standard Oil (Cal.)	1.05	45	13.6	12.2
Standard Oil (Ind.)	0.90	60	12.5	10.5
Standard Oil (Ohio)	0.85	32	12.1	8.9
Sun Oil	0.75	64	11.4	9.6
Superior Oil	1.00	45	13.2	12.0
Tesoro Petroleum	1.25	34	15.0	10.7
Texaco	0.90	54	12.5	10.9
Total Petroleum	1.05	47	13.6	11.5
Union Oil of California	0.90	50	12.5	10.3
United Refining	1.05	50	13.6	10.6

(1) Based on 1971-1974 average market return of 13.2% and U. S. Treasury Bill rate of 6.05%.

(2) SOURCE: Value Line, July 23, 1976.

(3) SOURCE: Arthur D. Little, Inc., estimates based on cost of debt of 9.5%.

TABLE II-27

OIL STOCK PRICES

	High	Low	12/31/74 P/E Ratio	12/31/74 Closing
Atlantic Richfield	113 3/4	73	11	20
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
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
Pennzoil	30 1/2	12 3/4	5	16 7/8
Phillips Petroleum	71 3/8	31 5/8	7	41 1/2
Shell Oil Co.	72 7/8	30 1/4	6	46
Signal	22 3/4	12 3/4	2	13 1/4
Skelly 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 (Cal.)	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 (Cal.)	56 3/4	27 1/4	4	38 1/2
Tenneco	24 3/4	16 3/4	6	23 1/4

SOURCE: Company Annual Reports, Wall Street Journal, Value Line 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 overall cost of capital. However, if the industry is moving beyond the "optimal" capital structure, the cost of capital will rise. Furthermore, given the fact that interest rates were high in 1973 and 1974, one might expect a continuing 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 7.8% to 11.0% range, theoretically, more firms will be able to make the investment. If the industry cost of capital lies in the 11.0% to 12.8% range, fewer firms can be expected to make the investment. Furthermore, estimates of the cost of capital provided include international operations and other aspects of the industry's business such as refining, marketing and chemicals in addition to domestic onshore oil production. Current standards of financial reporting do not provide sufficient data to estimate the cost of capital for domestic onshore production by itself.

III. PROPOSED EFFLUENT LIMITATIONS

1. Interim Final Limitations

In the Federal Register of October 13, 1976, the U.S. Environmental Protection Agency (EPA) published interim final effluent guidelines for segments of the onshore oil extraction industry. The industry segments for which guidelines were published were:

- onshore oil wells producing more than 10 barrels per day of oil,
- coastal platforms landward of the Chapman line,
- onshore oil wells whose produced formation water is used "beneficially."

A guideline was not published for onshore oil wells with an average daily production of less then 10 barrels per day called stripper wells. The BPT limitations on oil and grease are summarized as follows:

- onshore, non-stripper wells - no discharge;
- coastal platform - 72 mg/l daily maximum;
- beneficial use - 45 mg/l daily maximum (no discharge other than for the beneficial use).

These effluent limitations are intended to represent the degree of effluent reduction attainable by the application of the best practicable control technology currently available (BPT) for the industry subcategory.

The interim final BAT and new source effluent limitations differ from BPT only in that the coastal platforms have a zero discharge requirement. This report is an evaluation of the economic impact to the oil extraction industry segments of complying with the effluent limitations.

2. Current State Regulations

Introduction

An understanding of current state regulations for the disposal of brine from oil production is important in determining incremental compliance costs. Any implementation of stricter regulations must be examined in comparison with the present regulations and practices.

Arthur D. Little, Inc., and Jacobs Engineering Co. both have conducted surveys of the current state regulations, employing essentially the same techniques. Information was obtained by telephone interviews with representatives of the state regulatory agencies. In addition, the Arthur D. Little, Inc., survey involved a mail follow-up to confirm and elaborate on the information obtained by telephone.

Although there are some differences between the ADL and Jacobs findings, the results of the two surveys are generally consistent. There are, however, differences in several states between the regulatory requirements and the actual practices. These differences have been identified in the summaries of the state regulations and in Table III-1.

The following table, Table III-2, summarizes state brine disposal practices, focusing on reinjection. Note that although reinjection of brine may be required, it is infrequent that 100% of the brine actually is reinjected.

TABLE III-1
STATE BRINE DISPOSAL PRACTICES

State	Crude Oil Production 1975 (MM bbl's)	Reinjection Required Existing Wells	Reinjection Required New Wells	Number of Oil Wells 1975	% Brine Reinjected	% of Wells Whose Brine Is Reinjected	% of Oil Production Whose Brine Is Reinjected
Texas	1,222	no	no	160,603	94%	94% or more	94% or more
Louisiana	651	no	yes	27,734	66.66% onshore 0% offshore		
California	322	yes	yes	41,029	over 90%onshore 96% offshore	over 90%onshore 88% offshore	over 95%onshore 94% offshore
Oklahoma	163	yes	yes	71,576	100%	100%	100%
Wyoming	136	no	no	9,450	over 50%		
New Mexico	95.1	no	no	13,715	over 95%	over 95%	
Alaska	69.8			205	83% onshore 0% offshore	13% onshore 0% offshore	24% onshore 0% offshore
Kansas	59.1	no	yes	41,945	over 99%	over 99.9%	over 99%
Mississippi	46.6	no	yes	2,237	92-95%	92-95%	92-95%
Colorado	38.1	no	no	2,450	76%	47%	83%
Montana	32.8	no	no	3,247	90%	85-90%	36%
Florida	41.9	yes	yes	143	100%	100%	100%
Utah	42.3	no	no	1,323	over 96%	90%	
Illinois	26.1	no	no	23,373	over 50%	70%	
North Dakota	20.5	no	no	1,994	over 95%	90%	90%
Arkansas	16.1	no	no	7,308	92%	60%	not available
Michigan	24.4	yes	yes	3,655	96.8%	85%	95%
Ohio	9.6			16,611	70-80%	new wells 45-50% existing wells 10-15%	30%
Kentucky	7.6	no	yes	13,905	20%	50%	10%
Pennsylvania	3.3	no	no	32,095	0%	0%	0%
West Virginia	2.5	?	?	13,750	?	?	?
U.S. TOTAL	3,057			500,333			

Revision Date: 11/5/76

SOURCE: Arthur D. Little, Inc.

TABLE III-2

SUMMARY OF STATE REGULATIONS

Alabama

1. surface discharge: not allowed.

2. evaporation ponds: impervious pits for storage only.

3. reinjection: permitted; strict regs (since above methods not allowed for disposal, reinjection seems to be required); annular injection specifically allowed with approval.

Alaska

1. surface discharge: no rules (allowed, but water must be treated to EPA standards).

2. evaporation ponds: impervious pits for storage only (evap. ponds ineffective in Alaska).

3. reinjection: no rules re disposal - decisions made case-by-case; there are regulations for secondary recovery (mandatory reinjection could cause problems because of different salt contents).

Arizona

1. surface discharge: not allowed.

2. evaporation ponds: allowed if impervious.

3. reinjection: permitted; strict regs.

Arkansas

1. surface discharge: not allowed (allowed if fresh water, case-by-case decisions).

2. evaporation ponds: allowed with approval (law - no, practice - yes).

3. reinjection: permitted, strict regulations (must be to non-productive oil or gas zones or to zones of brackish water; rarely to depleted oil-bearing strata).

California

1. surface discharge: Jacobs survey: ocean discharge with treatment; phase-out 1977. ADL survey: not allowed.

2. evaporation ponds: impervious evaporation pits allowed by permit; percolation pits allowed in certain areas by permit; (evap. ponds allowed where no underlying fresh water deposits - west side of San Joaquin Valley).

3. reinjection: permitted, strict regs (brine must be returned to the

producing stratum or to a similar-water zone or oil core. If there are high boron or TDS counts, brine must be reinjected. No published regs).

Colorado

1. surface discharge: allowed only in areas where low salinity water is produced - water discharged for beneficial, agricultural uses; permit required. (Colorado Water Pollution Control Commission defines acceptable quality.)

2. evaporation ponds: for storage only; must be lined; permit required. (Unlined ponds may be permitted upon inspection; factors: salinity of water, topography of land, location of source.)

3. reinjection: permitted; strict regs (use of strata other than producing must be approved - water must generally be of equal or lesser quality than reinjected brine).

Florida

1. surface discharge: not allowed.

2. evaporation ponds: temporary disposal in pits with permit (must be closed containers).

3. reinjection: Jacobs survey: permitted; strict regs; ADL survey: required; must be reinjected to non-fresh water stratum.

Illinois

1. surface discharge: not allowed.

2. evaporation ponds: must be impervious; permit required (majority of producers dispose of brine in lined pits).

3. reinjection: permitted; strict regs (must not contain fresh water; cement casing).

Indiana

1. surface discharge: not allowed.

2. evaporation ponds: allowed if impervious; permit required.

3. reinjection: permitted; strict regs.

Kansas

1. surface discharge: not allowed.

2. evaporation ponds: allowed with permit, for emergency only (new leases: must provide storage facilities and dispose by reinjection; existing leases: ponds gradually being phased out. All evap. ponds still in use are in areas where groundwater supplies are not usable due to lack of volume).

3. reinjection: permitted; strict regs (must be disposed of in original stratum or salt-water stratum; since 1970, required except by variance where low chloride content).

Kentucky

1. surface discharge: ADL survey: not allowed; Jacobs survey: allowed with approval, based on final quality of receiving water.

2. evaporation ponds: ADL survey: not permitted for new wells; permitted for existing wells in some circumstances. Jacobs survey: no rules.

3. reinjection: permitted: strict regs (required for new wells or when necessary - i.e., high brine production - for existing wells; stratum must be approved by Div. of Water - Kentucky Geological Survey).

Louisiana

1. surface discharge: allowed into tidal waters; into streams with permit; oil limit 30 ppm (.3% onshore production to rivers and streams, 31.04% to non-potable water bodies; no offshore-produced brine to rivers and streams, but 78.78% of offshore-produced brine disposed of in non-potable water bodies - tidally affected, brackish, or unsuitable for human consumption or agricultural purposes).

2. evaporation pits: disposal pits allowed with permit (case-by-case approval).

3. reinjection: permitted; strict regs (not required; must be to salt-water zone).

Maryland

1. surface discharge: NPDES permit required; no regulations.

2. evaporation ponds: no rules.

3. reinjection: no specific rules regarding brine disposal; no permit or approval required.

Michigan

1. surface discharge: not allowed.

2. evaporation ponds: storage pits on approval (disposal in pits not allowed and also impractical, as evap. rate less than precipitation rate).

3. reinjection: permitted, strict regs; annular injection specifically allowed with approval (required by administrative regulation - any disposal method other than reinjection must be approved; reinjection prohibited to fresh water or chemical industry strata; only exceptions to reinjection are beneficial uses as dust control and ice removal from roadways).

Mississippi

1. surface discharge: ADL survey: only fresh water of less than 250 ppm - fed. std. - or less than 10,000 ppm - state std. - may be discharged; Jacobs survey: permit required; may be discharged to waters of 10,000 ppm or greater.

2. evaporation ponds: impervious disposal pits allowed with permit (approval especially extended to those wells in isolated areas).

3. reinjection: permitted; strict regs; annular injection specifically allowed with approval (required for new and existing wells, but for existing wells, under certain conditions, evaporation pits may be allowed; must be to non-productive or non-fresh-water stratum).

Missouri

1. surface discharge: NPDES permit required; no regulations.

2. evaporation ponds: no rules.

3. reinjection: permitted; vague regulations, must submit "pertinent data" for permit; decisions made case-by-case.

Montana

1. surface discharge: not allowed for brine; "fresh water" discharged in central Montana (3,000 ppm considered reasonably fresh; cattle will tolerate 10,000 ppm - surface discharge is for beneficial use).

2. evaporation ponds: allowed with permit (must be lined).

3. reinjection: permitted; strict regs (prohibited to fresh water stratum).

Nebraska

1. surface discharge: vague regulations; not allowed if unfit for domestic, livestock, or irrigation use; NPDES permit required.

2. evaporation ponds: impervious retaining pits allowed with permit.

3. reinjection: permitted; strict regs.

Nevada

1. surface discharge: not allowed.

2. evaporation ponds: disposal pits allowed if impervious.

3. reinjection: permitted; strict regs (more stringent rules for secondary recovery).

New Mexico

1. surface discharge: brine only into waters 10,000 ppm; "fresh water" allowed to discharge - only small amounts produced (not allowed).

2. evaporation ponds: approval necessary (strict requirements, no applications since 1967).

3. reinjection: permitted; strict regs (not required; must be returned to producing stratum; widespread except in areas where no fresh water, then evap. ponds or discharge to natural salt lakes).

New York

1. surface discharge: vague regulations; method of disposal must be approved; NPDES permit required.

2. evaporation ponds: storage pits with approval.

3. reinjection: permitted; strict regs (more stringent rules for secondary recovery).

North Dakota

1. surface discharge: not allowed.

2. evaporation ponds: impervious storage pits allowed with permit.

3. reinjection: permitted; strict regs (not required; strata must be approved).

Ohio

1. surface discharge: not allowed; few minor exceptions, i.e., dust and ice control in rural areas.

2. evaporation ponds: impervious storage pits allowed (trying to eliminate them).

3. reinjection: permitted; vague regs; interval must be approved; annular injection specifically allowed with approval (must be to producing stratum or stratum of similar of higher salt content).

Oklahoma

1. surface discharge: not allowed.

2. evaporation ponds: ADL survey: not allowed for brine disposal; pits containing salt water must be emptied and leveled; Jacobs survey: allowed if impervious; permit required.

3. reinjection: permitted; strict regs (required for all wells; must be injected to salt water zone).

Pennsylvania

1. surface discharge: industrial discharge permit required; allowed if free of oil and petroleum residues; allowance of surface discharge to streams based on fact that very small amounts of water are produced (measured in gallons/day) by individual wells; vague regulations - new rules being formulated.

2. evaporation ponds: storage pits must meet requirements; limits on turbidity if overflow.

3. reinjection: no rules; new rules now being formulated; must show that "pollution is improbable" - vague.

South Dakota

1. surface discharge: not allowed for brine; minor amount "fresh water" discharged - considered beneficial.

2. evaporation ponds: need approval.

3. reinjection: permitted; strict regs.

Tennessee

1. surface discharge: not allowed.

2. evaporation ponds: disposal pits allowed with approval.

3. reinjection: permitted; strict regs; annular injection specifically allowed with approval.

Texas

1. surface discharge: discharge to tidal waters allowed; discharge to streams allowed where quality high; gradually phasing out all surface discharge; small amount quality water discharged for beneficial uses.

2. evaporation ponds: allowed if impervious; permit required.

3. reinjection: permitted; strict regs (must be to salt-water zone).

Utah

1. surface discharge: not allowed for brine; "fresh water" discharged for agric. use.

2. evaporation ponds: allowed if impervious (technically allowed only for emergencies).

3. reinjection: permitted; strict regs (to producing stratum or to stratum of equivalent or greater salt content).

Virginia

1. surface discharge: permit required; must meet water quality standards for industrial discharges; vague regs.

2. evaporation ponds: no rules.

3. reinjection: permitted; strict regs.

West Virginia

1. surface discharge: permit required; must meet water quality standards for industrial discharges; no discharge of water unfit for general use may be made (state lets small strippers dump brine to ground, although state law requires reinjection).

2. evaporation ponds: no rules (no information).

3. reinjection: required; vague regs formation must be approved.

Wyoming

1. surface discharge: allowed if quality within limits; permit required; oil content not to exceed 10 ppm (surface discharge of brine not allowed; fresh water may be discharged - beneficial use - stock; no specific quality guidelines).

2. evaporation ponds: no rules (lined pits not required; case-by-case approval of such disposal).

3. reinjection: permitted; strict regs (trend towards reinjection; may be injected to any stratum containing water of a poorer quality).

SOURCE: Arthur D. Little, Inc., estimates

3. Cost of Pollution Abatement Systems

The costs of compliance with the potential effluent guidelines have been developed by Jacobs Engineering, Inc., under contract to EPA.[1] Jacobs collected costs of reinjection and treatment costs as a function of water capacity at existing facilities in several states and developed engineering cost estimates in situations where the desired technology is not currently in use.

Using the cost data points provided by Jacobs, functional relationships were developed between the compliance costs and water volumes by a least square fitting of the function to the data point. The functions were of the following form:

$$CC = \text{Constant for } 0 \leq CAPTY \leq 100 \text{ B/D}$$

$$CC = A\,(\log CAPTY)^{B} \text{ for } 100 \leq CAPTY \text{ (in B/D)}$$

where

CC: Capital cost or operating costs of the treatment and disposal equipment (in 1975$),

CAPTY: The capacity of the installation,

A,B: Parameter values found through least squares regression.

The functions then were used in the economic impact analysis. Tables III-3 and III-4 summarize the cost functions.

Reinjection costs were developed for each of the states studied. In the cases of on-land Louisiana and Texas, there were not enough data points to warrant a distinction between the states, and they were combined.

The treatment regulations divided the onshore producers into stripper wells (less than 10 barrels per day), non-stripper wells and beneficial uses

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[1] EPA Contract No. 68-01-3278, J.E.C. Job No. 27-1460.

TABLE III-3

CAPITAL COSTS FOR DISPOSAL

OF OIL FIELD EFFLUENT

($1,000's of 1975 $)

	Disposal Equipment Capacity (bbl/day of water)				
	10	100	500	1,000	10,000
Reinjection					
Wyoming	75	80	140	175	300
Texas/Louisiana (on land)	30	46	115	160	410
Pennsylvania[a]					
Case I	28	52	130	190	470
Case II	15	24	47	61	110
Texas (platforms)	400	400	420	500	1,600
Louisiana (platforms)	400	400	420	470	1,680
Treatment					
Non-Stripper & Beneficial	62	62	62	96	198
Platform	53	53	80	125	340

a. Case I assumes water flooding not now practical and Case II assumes it is in practice. Case II predominates in Pennsylvania.

SOURCE: Jacobs Engineering, Inc.

Revision Date: 8 July 1976

TABLE III-4

OPERATING COSTS FOR DISPOSAL
OF OIL FIELD EFFLUENT
($1,000's of 1975 $)

	Disposal Equipment Capacity (bbl/day of water)				
	10	100	500	1,000	10,000
Reinjection					
Wyoming	8	8.8	15	18.5	32
Texas/Louisiana (on land)	8.5	9.5	18.5	24	43
Pennsylvania[a]					
Case I	7.6	14	33	46	100
Case II	5	6.5	13	16.5	32
Texas (platforms)*	26	26	27	32	122
Louisiana (platforms)*	16	16	16.5	22	134
Treatment					
Non-Stripper & Beneficial	13	13	14	18.5	49
Platform	8	8	10.3	15.5	47

a. Case I assumes water flooding not now practical and Case II assumes it is in practice. Case II predominates in Pennsylvania.

*New costs from Jacobs are higher.

SOURCE: Jacobs Engineering, Inc.

Revision Date: 8 July 1976

on land, and near coastal platforms. The impact of potential regulations on stripper wells has not been evaluated in this report. The platforms are assumed to use a dissolved air flotation unit. The larger on-land producers are assumed to use dissolved air flotation units up to 2,500 BPD of water and induced air flotation for units of greater than 2,500 BPD water flow.

The assumption was made that virtually none of the required facilities for compliance with a reinjection or treatment guideline are currently on site. To the extent that usable equipment is currently on site, the compliance costs would be overstated.

IV. ECONOMIC IMPACT ASSESSMENT METHODOLOGY

1. Scope of the Analysis

This chapter describes the methodology used to estimate the economic impact of effluent limitations for the discharge of produced formation water from onshore oil wells with a production greater than 10 barrels per day. The regulation is applicable to all U.S. wells on shore of the Chapman Line. However, the economic impact analysis is confined to wells in Texas, Louisiana, and Wyoming, as representative of non-complying production. While classified as onshore, there are a number of wells in bays and estuaries producing to platforms inside of the Chapman Line. These "onshore" platforms have been treated as a separate category.

The analysis used the following measures of economic impact:

- average increase in production cost
- foregone production
- total capital cost of pollution control
- number of wells closed rather than brought into compliance
- loss of reserves
- implied increase in crude oil prices

The costs of compliance with the effluent limitation were estimated by the engineering contractor under a separate contract with EPA.[1] Regression analyses were made of the engineering data in order to represent it as cost functions (see Chapter III).

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[1] Contract Number 68-01-3278, JEC Job No. 27-1460.

The production cost models were developed for this contract by revising and updating the production costs in Bureau of Mines Information Circular IC8561 to 1975 (see Chapter V). The production profiles were also developed by the engineering contractor estimating the numbers of wells and their productivity in each state.

The model of producer response to the regulation using a discounted cash flow analysis of the decision whether to invest in reinjection equipment was developed under this contract and applied to the non-complying production profiles of the three states. The production unit in the analysis is a cluster of producing wells on one or adjacent leases under the control of one operator and which would require at least one reinjection unit. The productivity values are averages for the production unit.

Given inherent uncertainties about future cost and price conditions, such as world crude prices, cost of capital, and production decline rates, a range of possible impacts was examined through sensitivity analysis and expressed in terms of high, most likely, and low estimates.

2. Model of Producer Decision Making

An economic impact analysis requires a model portraying the response of producers to the regulation. If the oil well operator were able to increase prices sufficiently to cover all of the costs of compliance with the effluent guidelines, the only economic impact would be higher crude oil prices. However, as discussed in Chapter II, crude oil pricing patterns do not allow operators to change crude prices in the face of the higher production costs resulting from the effluent guidelines. The producer must decide whether the well will continue to be economically viable in spite of the higher costs. Therefore, the base case for economic impact analysis assumes that producers will absorb all pollution control costs. A sensitivity analysis deals with the case in which producers are able to pass on their increased costs to the consumer.

To minimize the cost of compliance that he will have to absorb, each operator will try to find the solution which suits him best at that moment. For example, he may pool his efforts with other operators, or he may be able to reduce his cost of compliance by buying used equipment rather than new equipment.

Given the wide variety of options, it is impractical to allow for all possible operators' decisions. Therefore, two simplifying assumptions have been made:

- operators of individual production units would not pool their efforts in trying to comply with the regulation; and
- operators would base their decisions of whether to comply with the regulation on a rational economic basis alone.

The first assumption will result in a "worst case" (i.e., high) estimate of the potential impact. Economies of scale apply to the treatment equipment required to comply with the proposed regulation. Therefore, considerably lower costs of compliance, on a per unit basis, are possible if operators pool their efforts by combining investment in one large treatment unit, rather than several smaller units, as assumed in the analysis.

The second assumption does not imply that some producers would continue production if they knew it to be economically irrational. Rather, it is possible that where the impact analysis methodology specifies an exact definition of economic viability, in reality some small producers may not know precisely whether continued production makes economic sense. It is also possible that a producer may wish to continue production of an otherwise sub-economical well for factors other than simply the profitability of the well itself. The rational economic decision assumed in the impact analysis is restricted to the economic viability of the individual production units.

The assumption about rational economic behavior of operators not currently complying with the regulations implies that:

- an operator will first estimate how much he will have to invest in formation water treatment and reinjection facilities, and what the additional operating costs will be if he comes into compliance with the effluent guidelines;
- next, he will estimate how much oil production to expect over the remaining life of his production unit;
- he will then assess whether the production unit's remaining production can be expected to pay for the additional costs necessary for the treatment equipment;
- if he finds that the remaining production will not pay for the investment and operating costs for the treatment and disposal equipment, he will shut in his production unit; this will result in the loss of those barrels of oil which would have been otherwise produced;
- if, on the other hand, he finds that the remaining production will pay for the additional costs, he will continue to produce after having installed the required equipment; some of the potential production will still be lost because the increase in operating costs will result in a decrease in the life of the production unit.

3. Analysis of Production Units

The decision process of the producer faced with the effluent limitation is modelled by the cash flow program depicted in Figure IV-1.

As background for decision making, the following parameters are considered for each state:

- production costs as a function of production unit size,
- cost of compliance (investment cost) as a function of size,
- fiscal variables (e.g., taxes, royalties, etc.),
- price assumptions,
- cost of capital.

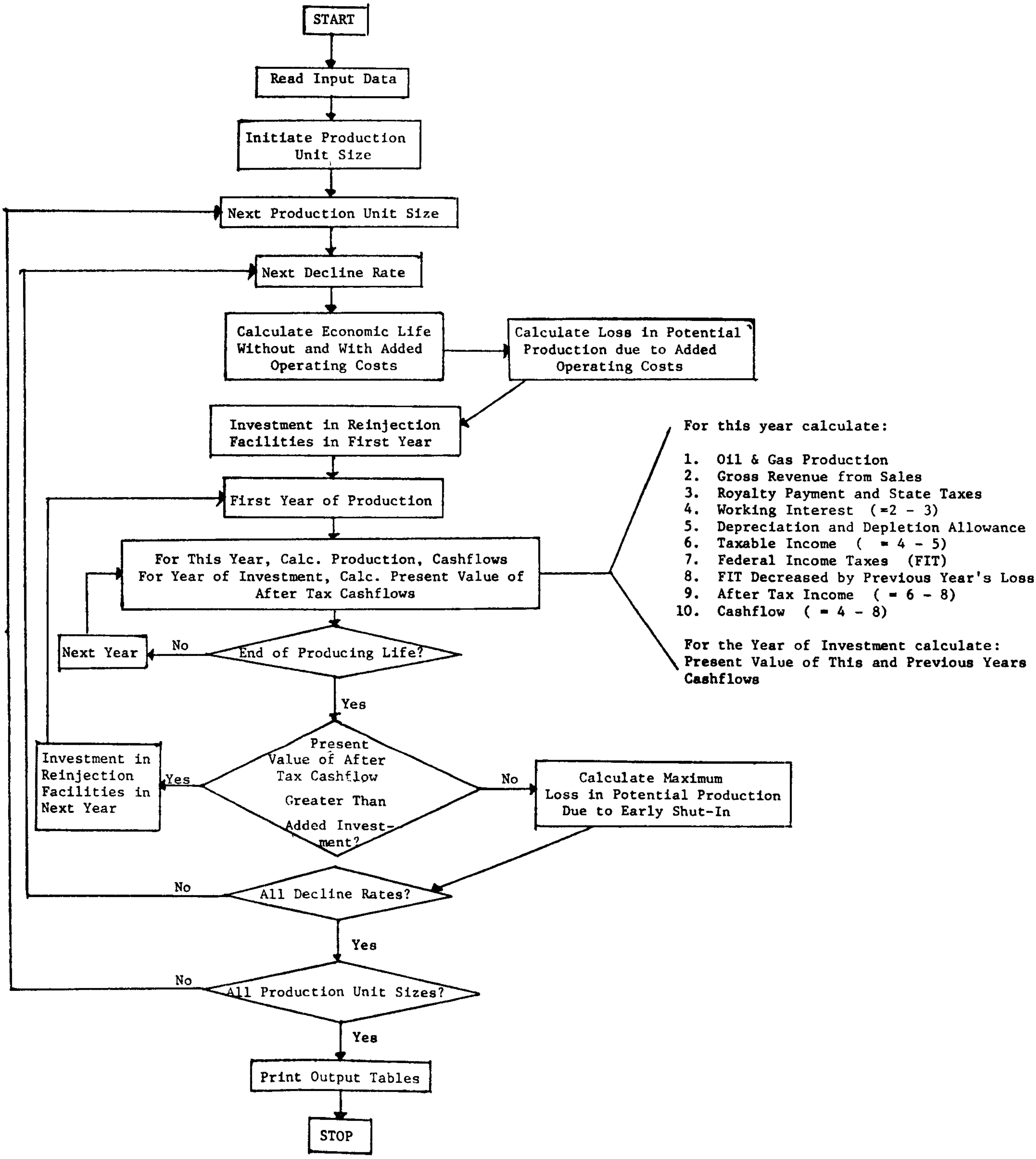
Within this set of parameters, the cash flow is analyzed for a range of production unit sizes and production decline rates. These variables are set at initial values at the beginning of the program and changed with successive cash flow analyses.

The impact of pollution control is first assessed by determining a production unit's economic life both with and without the additional operating costs attributable to the pollution control equipment (Table IV-1, sections 1-2). The economic life of a lease or production unit will terminate in the year in which gross revenue from oil production, decreased by royalty and state tax payments, is just equal to the operator's out-of-pocket operating costs (i.e., his variable costs). Lost potential production as a result of a shortened life is recorded (Table IV-1, section 3).

Impact of pollution control is further analyzed by establishing the minimum well productivity (for the given production decline rate) required to

Figure IV-1

COMPUTER FLOW DIAGRAM



SOURCE: Arthur D. Little, Inc.

TABLE IV-1

SAMPLE STATE

Section 1

Producing Life Before Investment in Reinjection (years)
Average Welldepth: 4000 ft.

Initial Productivity (barrels per day):

Decline Rate	25	50	100	200
.05	51.4	64.9	78.5	90.0
.10	25.3	31.9	38.5	45.0
.15	16.6	20.9	25.1	29.4
.20	12.3	15.4	18.5	21.6
.25	9.6	12.0	14.5	16.9

Section 2

Producing Life After Investment in Reinjection (years)
Average Welldepth: 4000 ft.

Initial Productivity (barrels per day):

Decline Rate	25	50	100	200
.05	49.6	63.2	76.7	90.0
.10	24.4	31.0	37.6	44.2
.15	16.0	20.3	24.6	28.8
.20	11.3	14.9	18.0	21.2
.25	9.3	11.7	14.1	16.6

Section 3

Loss in Potential Production Due to Added Operating Cost (barrels)
Average Welldepth: 4000 ft.

Initial Productivity (barrels per day):

Decline Rate	25	50	100	200
.05	12136.6	12186.6	12186.5	0
.10	5772.6	5772.6	5772.6	5772.0
.15	3634.6	3634.6	3634.6	3634.6
.20	2565.6	2565.6	2565.6	2565.6
.25	1924.2	1924.2	1924.2	1924.2

SOURCE: Arthur D. Little, Inc.

TABLE IV-1 (cont.)

Section 4

Required Remaining Life to Pay for Investment (years)
Average Welldepth: 4000 ft.

Initial Productivity (barrels per day):

Decline Rate	25	50	100	200
.05	6.3	6.4	6.4	13.1
.10	4.0	4.1	4.0	4.1
.15	3.1	3.1	3.0	3.0
.20	2.3	2.4	2.6	2.5
.25	2.1	2.0	2.2	2.1

Section 5

Lowest Productivity Which Will Pay for Investment (barrels per day)
Average Welldepth: 4000 ft.

Initial Productivity (barrels per day):

Decline Rate	25	50	100	200
.05	2.7	2.7	2.7	3.9
.10	2.9	2.9	2.9	2.9
.15	3.0	3.0	3.0	3.0
.20	2.3	2.4	2.6	2.5
.25	2.1	2.0	2.2	2.1

Section 6

Loss in Potential Production Due to Early Shut-In (barrels)
Average Welldepth: 4000 ft.

Initial Productivity (barrels per day):

Decline Rate	25	50	100	200
.05	53312.4	54078.8	53785.4	135573.1
.10	34227.7	35428.0	34540.8	35455.5
.15	27888.0	24829.4	26426.8	20151.7
.20	20348.6	29527.8	25805.5	22630.0
.25	18157.0	17585.7	19425.9	18216.3

SOURCE: Arthur D. Little, Inc.

pay for the investment in the pollution control equipment and the cost of operating it. Different production units will be caught at different points of their producing lives when the compliance date for pollution control arrives. Given a unit's production decline rate and average well productivity at that point in time, there will or will not be sufficient future cash flow from oil production to cover the cost of pollution control equipment. If the present value of the future cash flows is less than the required investment, the operator will choose to abandon his wells rather than continue to operate, and thus forego the production which otherwise would have resulted until the end of the unit's economic life.

A trial-and-error method is utilized to determine the minimum well productivity, or latest year within the economic life of a given production unit, which justifies an investment in pollution control equipment. This trial-and-error process is started by the assumption that the investment is made in the first year of a unit's life. Cash flows related to the unit's production from the first to the last year of its economic life are then calculated and converted into present values (Table IV-2 presents a typical cash flow for the ex ante, i.e., no-investment,case). Next it is determined whether the present value of all cash flows subsequent to the year of investment are sufficient to cover (i.e., are greater than) the required investment. If so, then the year of investment is advanced until the present value of the remaining years' cash flows just equal the cost of the pollution control equipment. This year may be termed the "last year of investment." Table IV-3 presents the cash flow results for a production unit whose last year of investment is the

TABLE IV-2

EPA FORMATION WATER DISPOSAL ANALYSIS,REINJECTION NONSTRIPPER

SAMPLE STATE

CASH FLOW TABLE FOR EX ANTE CASE

DEPTH IN FT	-.00
DECLINE RATE	.10
WELLPRODUCTIVITY	100.00
YEAR OF ADD. INV.	1
PV. OF AFTER TAX CASHFLOW	1901185.30
ADD. INVESTMENT IN $	********
ADD. INTANGIBLES IN $	.00
ADD. OPERATING COSTS IN $/YR	8000.00
DISCOUNT RATE	.10
AVERAGE E.O.L. PRODUCTIVITY	3.96
WATER/OIL RATIO	.00

YR	GROSS INC	STATE TAX	OP. COSTS	TOT.DEPRCN	TOT.OVERH	BEFORE	DEPL.ALL.	TAXBLE IN	F.T. TAX	AFTER TAX	CASHFLOW	LIFT COST
1	910219.	174762.	69685.	42002.	0.	134420.	0.	134420.	64521.	69898.	601250.	1.78
2	819197.	157286.	69685.	37802.	0.	554424.	0.	554424.	266124.	288301.	326102.	3.16
3	737277.	141557.	69685.	34022.	0.	492013.	0.	492013.	236166.	255847.	289869.	3.19
4	663549.	127401.	69685.	30619.	0.	435843.	0.	435843.	209205.	226639.	257258.	3.21
5	597195.	114661.	69685.	27558.	0.	385291.	0.	385291.	184940.	200351.	227909.	3.25
6	537475.	103195.	69685.	24802.	0.	339793.	0.	339793.	163101.	176692.	201494.	3.28
7	483728.	92876.	69685.	22322.	0.	298845.	0.	298845.	143446.	155400.	177721.	3.32
8	435355.	83588.	69685.	20089.	0.	261992.	0.	261992.	125756.	136236.	156325.	3.36
9	391819.	75229.	69685.	18081.	0.	226825.	0.	226825.	109836.	118989.	137069.	3.41
10	352637.	67706.	69685.	16272.	0.	196974.	0.	193974.	95507.	103466.	119739.	3.47
11	317374.	60936.	69685.	14645.	0.	172108.	0.	172108.	82612.	89496.	104141.	3.53
12	285636.	54842.	69685.	13181.	0.	147928.	0.	147928.	71006.	76923.	90103.	3.59
13	257073.	49358.	69685.	11863.	0.	126167.	0.	126167.	60560.	65607.	77470.	3.67
14	231365.	44422.	69685.	10676.	0.	106582.	0.	106582.	51159.	55423.	66099.	3.75
15	208229.	39980.	69685.	9609.	0.	88955.	0.	88955.	42698.	46257.	55865.	3.84
16	187406.	35982.	69685.	8648.	0.	73091.	0.	73091.	35084.	38007.	46655.	3.94
17	168665.	32384.	69685.	7783.	0.	58814.	0.	58814.	28231.	30583.	38366.	4.06
18	151799.	29145.	69685.	7005.	0.	45964.	0.	45964.	22063.	23901.	30906.	4.18
19	136619.	26231.	69685.	6304.	0.	34399.	0.	34399.	16511.	17887.	24192.	4.32
20	122957.	23608.	69685.	5674.	0.	23990.	0.	23990.	11515.	12475.	18149.	4.48
21	110661.	21247.	69685.	5106.	0.	14623.	0.	14623.	7019.	7604.	12710.	4.65
22	99595.	19122.	69685.	4596.	0.	6192.	0.	6192.	2972.	3220.	7816.	4.84
23	192589.	36977.	69685.	4136.	0.	81790.	0.	81790.	39259.	42531.	46667.	8.55
24	173330.	33279.	69685.	3723.	0.	66643.	0.	66643.	31989.	34654.	38377.	8.78
25	155997.	29951.	69685.	3350.	0.	53010.	0.	53010.	25445.	27565.	30916.	9.04
26	140397.	26956.	69685.	3015.	0.	40741.	0.	40741.	19555.	21185.	24200.	9.34
27	126357.	24261.	69685.	2714.	0.	29698.	0.	29698.	14255.	15443.	18157.	9.66
28	113722.	21835.	69685.	2442.	0.	19760.	0.	19760.	9485.	10275.	12717.	10.02
29	102350.	19651.	69685.	2198.	0.	10815.	0.	10815.	5191.	5624.	7822.	10.42
30	92115.	17686.	69685.	1978.	0.	2765.	0.	2765.	1327.	1438.	3416.	10.86
31	82903.	15917.	69685.	1781.	0.	-4480.	0.	-4480.	0.	2150.	-2699.	11.65

SOURCE: Arthur D. Little, Inc. estimates

TABLE IV-3

EPA FORMATION WATER DISPOSAL ANALYSIS-REINJECTION NONSTRIPPER

SAMPLE STATE

CASH FLOW TABLE FOR EX POST CASE
ADDITIONAL INVESTMENT IN YEAR 26

DEPTH IN FT	-.00
DECLINE RATE	.10
WELLPRODUCTIVITY	100.00
YEAR OF ADD. INV.	26
PV. OF AFTER TAX CASHFLOW	58175.28
ADD. INVESTMENT IN $	75000.00
ADD. INTANGIBLES IN $	.00
ADD. OPERATING COSTS IN $/YR	8000.00
DISCOUNT RATE	.10
AVERAGE E.O.L. PRODUCTIVITY	4.42
WATER/OIL RATIO	.00

YR	GROSS INC	STATE TAX	OP. COSTS	TOT.DEPRCN	TOT.OVERH	BEFORE	DEPL.ALL.	TAXBLE IN	F.I. TAX	AFTER TAX	CASHFLOW	LIFT COST
1	910219.	174762.	69685.	47202.	0.	134219.	0.	134219.	64425.	69790.	-601346.	1.78
2	819197.	157286.	69685.	37982.	0.	554244.	0.	554244.	266037.	288207.	326189.	3.16
3	737277.	141557.	69685.	34184.	0.	491851.	0.	491851.	236089.	255763.	289946.	3.19
4	663549.	127401.	69685.	30765.	0.	435698.	0.	435698.	209135.	226563.	257328.	3.21
5	597195.	114661.	69685.	27689.	0.	385159.	0.	385159.	184876.	200283.	227972.	3.25
6	537475.	103195.	69685.	24920.	0.	339675.	0.	339675.	163044.	176631.	201551.	3.28
7	483728.	92876.	69685.	22428.	0.	298739.	0.	298739.	143395.	155344.	177772.	3.32
8	435355.	83588.	69685.	20185.	0.	261896.	0.	261896.	125710.	136186.	156371.	3.36
9	391819.	75229.	69685.	18167.	0.	228738.	0.	228738.	109794.	118944.	137111.	3.41
10	352637.	67706.	69685.	16350.	0.	198896.	0.	198896.	95470.	103426.	119776.	3.47
11	317374.	60936.	69685.	14715.	0.	172038.	0.	172038.	82578.	89460.	104175.	3.53
12	285636.	54842.	69685.	13244.	0.	147866.	0.	147866.	70975.	76890.	90134.	3.59
13	257073.	49358.	69685.	11919.	0.	126111.	0.	126111.	60535.	65577.	77497.	3.67
14	231365.	44422.	69685.	10727.	0.	106531.	0.	106531.	51135.	55396.	66123.	3.75
15	208229.	39980.	69685.	9655.	0.	88909.	0.	88909.	42677.	46233.	55887.	3.84
16	187406.	35982.	69685.	8669.	0.	73050.	0.	73050.	35064.	37986.	46675.	3.94
17	168665.	32384.	69685.	7820.	0.	58776.	0.	58776.	28213.	30564.	36384.	4.06
18	151799.	29145.	69685.	7038.	0.	45930.	0.	45930.	22047.	23884.	30922.	4.18
19	136619.	26231.	69685.	6334.	0.	34369.	0.	34369.	16497.	17872.	24206.	4.32
20	122957.	23608.	69685.	5701.	0.	23963.	0.	23963.	11502.	12461.	18162.	4.47
21	110661.	21247.	69685.	5131.	0.	14599.	0.	14599.	7007.	7591.	12722.	4.65
22	99595.	19122.	69685.	4618.	0.	6170.	0.	6170.	2962.	3209.	7826.	4.84
23	192589.	36977.	69685.	4156.	0.	81771.	0.	81771.	39250.	42521.	46677.	8.55
24	173330.	33279.	69685.	3740.	0.	66625.	0.	66625.	31980.	34645.	38385.	8.78
25	155997.	29951.	69685.	3366.	0.	52994.	0.	52994.	25437.	27557.	30923.	9.04
26	140397.	26956.	77685.	22578.	0.	13178.	0.	13178.	6326.	6853.	29430.	8.92
27	126357.	24261.	77685.	20320.	0.	4092.	0.	4092.	1964.	2128.	22448.	9.28
28	113722.	21835.	77685.	18288.	0.	-4086.	0.	-4086.	0.	1961.	14202.	9.87
29	102350.	19651.	77685.	16459.	0.	-11446.	0.	-11446.	0.	1964.	5013.	10.73
30	92115.	17686.	77685.	14813.	0.	-18070.	0.	-18070.	0.	0.	-3256.	11.68

SOURCE: Arthur D. Little, Inc. estimates

26th year of its economic life. In all years beyond that year, if presented with the initial investment decision, the operator would decide to abandon his well and forfeit future potential production (Table IV-1, section 4). The average well productivity in the last year of investment is the minimum required to justify investment (Table IV-1, section 5). The maximum loss in potential production will occur if the pollution control compliance date forces an operator to make an investment decision after the last year of investment, when future production will not cover the investment cost of compliance (Table IV-1, section 6). The program calculates this maximum potential lost production, and these results are retained along with the other calculated impacts.

The program next chooses a new combination of the parameters of production unit size and decline rate, and recalculates the impacts in terms of lost production due to the incremental operating and investment costs required by pollution control facilities.

This procedure is repeated until all possible combinations of different production unit sizes and production decline rates which are believed to exist in the population of potentially impacted production units of the particular state in question have been analyzed.

4. Analysis of Selected States

The production profiles of non-complying units in the three states were developed by Jacobs Engineering in 1975. Table IV-4 shows an example of such a production profile. While the regulation will not come into effect until 1977, when the profile will be somewhat different, no attempt has been made to modify the 1975 populations. Given the relatively small time interval between 1975 and 1977, it can be assumed that the production profiles based on 1975 data adequately represent the number and size of non-complying production units in 1977.

The results of the impact analysis on the model production unit, described in the previous section, are then compared to the production profiles of non-complying wells. This comparison establishes which of the non-complying production units will have to shut in because the remaining production will not pay for the pollution control costs and how much production will be foregone by those production units which will be able to comply but which will experience an increase in operating costs due to the pollution control equipment.

A flow diagram of the computer program developed to apply the results of the production unit analysis to the state's production profiles is shown in Figure IV-2. The cells of each state's production profile show the number of production units in the state with the specified number of wells and average well productivity corresponding to the location of the cell in the production profile's matrix (see Table IV-4). For the value of average productivity and number of wells per unit for each cell, the program first establishes whether the production unit contained in the cell would have to be shut in or not. If so, the number of wells shut in and the total production loss are calculated; Table IV-5 shows the results for Wyoming. If not, the total investment required in pollution control equipment, the production lost due

TABLE IV-4

EPA FORMATION WATER DISPOSAL ANALYSIS, REINJECTION

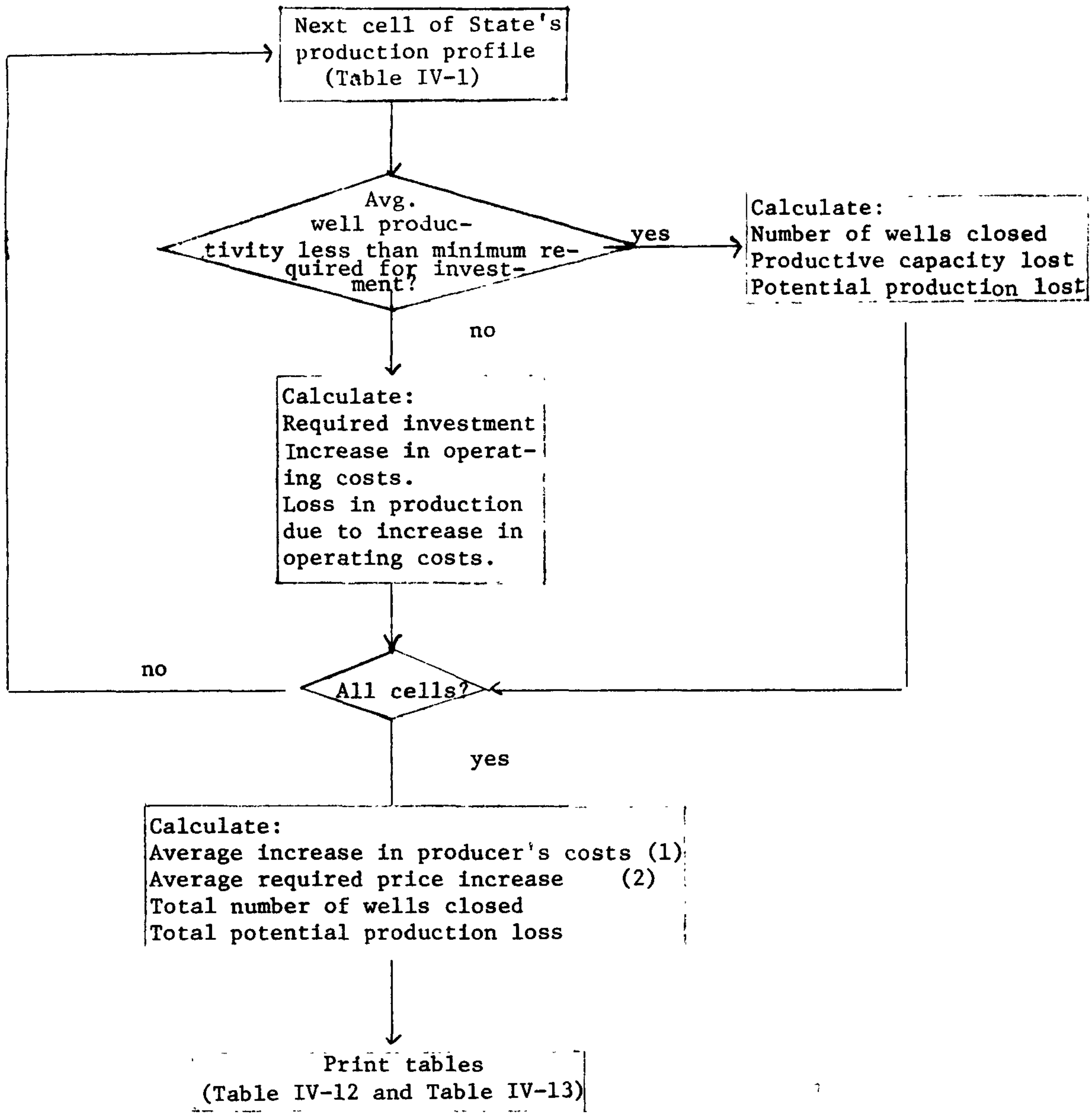
STATE WYOMING

AVG PROD/WELL (B/D)	PRODUCING UNIT CATEGORIES (# wells/producing unit) 2.	5.	9.	13.	18.	25.	35.	50.	80.	100.
11.50	2	0	4	1	0	0	0	0	0	0
12.50	6	1	1	2	0	0	0	0	[illegible]	1
13.50	10	2	1	1	0	0	[illegible]	0	1	[illegible]
14.50	3	1	0	0	0	1	0	[illegible]	[illegible]	[illegible]
15.50	4	1	1	0	0	1	[illegible]	[illegible]	[illegible]	[illegible]
18.00	20	3	1	1	1	1	0	0		[illegible]
25.00	27	9	5	1	0	0	1	0	[illegible]	[illegible]
35.00	23	4	0	4	0	0	0	[illegible]		
45.00	11	1	5	0	1	0	1	2	[illegible]	[illegible]
55.00	4	3	1	1	1	2	4	[illegible]	[illegible]	[illegible]
65.00	6	4	0	0	1	0	0	1	[illegible]	[illegible]
75.00	1	3	0	0	0	1	1	[illegible]	[illegible]	
85.00	[illegible]	1	0	1	0	0	[illegible]	[illegible]		
95.00	5	1	0	0	0	0	0	[illegible]	[illegible]	[illegible]
125.00	9	2	0	0	0	0	0	0	[illegible]	[illegible]
175.00	4	0	0	0	0	0	[illegible]	[illegible]	[illegible]	
225.00	0	0	0	0	1	0	[illegible]	[illegible]	[illegible]	
275.00	0	0	0	0	0	0	0	[illegible]	[illegible]	[illegible]
300.00	0	0	[illegible]	0	0	0	0	[illegible]	[illegible]	[illegible]

SOURCE: Jacobs Engineering, Inc.

FIGURE IV-2

COMPUTER FLOW DIAGRAM



(1) Producers absorb all costs (Base Case)
(2) Producers pass on all costs

SOURCE: Arthur D. Little, Inc., estimates

TABLE IV-5

EPA FORMATION WATER DISPOSAL ANALYSIS, REINJECTION NONSTRIPPER

STATE WYOMING

PRODUCTION LOST AFTER REGULATION BY CATEGORY
(PERCENTAGE OF UNREGULATED PRODUCTION)

AVG PROD/WELL (B/D)	PRODUCING UNIT CATEGORIES (# wells) 2.	5.	9.	13.	18.	25.	35.	50.	80.	100.
11.50	100.0	*****	4.4	3.5	*****	*****	*****	*****	*****	*****
12.50	100.0	5.7	4.0	3.1	*****	*****	*****	*****	*****	.7
13.50	100.0	59.9	3.7	2.9	*****	*****	*****	*****	*****	*****
14.50	100.0	4.9	*****	*****	*****	1.7	*****	*****	*****	*****
15.50	100.0	4.6	*****	*****	*****	1.6	*****	*****	*****	*****
18.00	100.0	*****	2.7	2.1	1.7	1.4	*****	*****	*****	*****
25.00	33.8	3.0	2.0	1.6	*****	*****	.8	*****	*****	*****
35.00	23.7	19.8	*****	1.2	*****	*****	*****	*****	*****	*****
45.00	18.6	15.3	1.2	*****	.8	*****	.5	.3	*****	*****
55.00	15.4	12.5	1.1	.8	.6	.5	*****	*****	*****	.2
65.00	13.2	10.6	*****	*****	.5	*****	*****	.3	.2	*****
75.00	11.6	9.2	*****	*****	*****	.4	.3	*****	*****	*****
85.00	10.4	8.2	*****	.6	*****	*****	*****	*****	*****	*****
95.00	9.4	7.3	*****	*****	*****	*****	*****	*****	*****	*****
125.00	7.3	5.7	*****	*****	*****	*****	*****	*****	*****	*****
175.00	5.5	*****	*****	*****	*****	*****	*****	*****	*****	*****
225.00	*****	*****	*****	*****	.2	*****	*****	*****	*****	*****
275.00	*****	*****	*****	*****	*****	*****	*****	*****	*****	*****
300.00	*****	*****	*****	*****	*****	*****	*****	*****	.0	*****

SOURCE: Arthur D. Little, Inc. estimates

to the increase in operating cost, and the total remaining production are calculated on an annual basis. As with the model production unit analysis, the calculations are done using a representative range of decline rates (see Table IV-6).

For those production units which are projected to make the necessary investments to come into compliance, an estimate is made of the average increase in production costs per unit of production. This cost increase is calculated using the following formula:

$$\text{COST} = \frac{\text{PV[INVMT} - \text{IC]} - (1-t) \times \text{SUM(PV[OC}_i + \text{DEP}_i\text{])}}{\text{SUM (PV[PROD}_i\text{])}}$$

where

COST	, the average per barrel cost increase for impacted producers
PV [ ]	, the present value operator
SUM ( )	, the summation of annual values
INVMT	, the investment in pollution control equipment
IC	, investment credit on investment in pollution control equipment
t	, the federal tax rate
OC_i	, annual operating costs for pollution control equipment
DEP_i	, annual depreciation of investment in pollution control equipment
$PROD_i$	, annual production of oil

The results of this type of calculation for Wyoming are shown in the last column of Table IV-6 .

TABLE IV- 6

EPA FORMATION WATER DISPOSAL ANALYSIS,REINJECTION NONSTRIPPER

STATE WYOMING

RESULTS OF IMPACT ANALYSIS

AVERAGE WELL DEPTH 0 FEET

PRODUCERS ABSORB ALL COSTS

TOTAL PRODUCING WELLS IN 1975	8656
TOTAL DAILY OIL PRODUCTION IN 1975	348605. B/D
1975 TOTAL API RESERVES	877.4 MMB
POTENTIALLY IMPACTED PRODUCING WELLS IN 1975	1594
POTENTIALLY IMPACTED PRODUCTION IN 1975	89853. B/D

DECLINE RATE	WELLS CLOSED			PRODUCTIVE CAPACITY LOST			RESERVES LOST				COMPLIANCE COSTS	
	1975	PCT IMP	PCT TOTAL	1975 (B/D)	PCT IMP	PCT TOTAL	LOST (1) (MMB)	PCT TOTAL	LOST (2) (MMB)	PCT TOTAL	1975 INV (MM$)	INC OPCOST ($/B)
.080	90	5.65	1.04	1341.	1.49	.38	10.4	1.19	4.5	.52	20.326	.072
.100	90	5.65	1.04	1327.	1.48	.38	8.8	1.00	3.6	.41	20.264	.072
.120	144	9.03	1.66	2582.	2.87	.74	5.2	.59	6.2	.71	18.178	.067
.140	144	9.03	1.66	2555.	2.84	.73	3.5	.40	5.3	.60	18.116	.067
.150	144	9.03	1.66	2541.	2.83	.73	4.5	.51	4.9	.56	18.084	.067

(1) TOTAL PRODUCTION LOST DUE TO INCREASED OPERATING COSTS

(2) TOTAL PRODUCTION LOST DUE TO WELL CLOSURES

SOURCE: Arthur D. Little, Inc. estimates

V. CHARACTERIZATION OF AFFECTED PRODUCTION

1. Production Profiles

In December 1975 there were 493,729 producing oil wells in the United States, including offshore, of which 74% were stripper wells producing less than 10 barrels per day (Table V-1). The 132,213 non-stripper wells accounted for 88.6% of the total oil production and had an average productivity of 56 barrels per day. The three states included in the impact analysis (Texas, Louisiana, and Wyoming) had two billion barrels of production, 66% of the U.S. total.

Offshore production, primarily off Louisiana, was 16% of U.S. oil production (Table V-2). The three states had 1.65 million barrels of onshore production, which was 65% of total U.S. onshore production in 1975. Of the onshore production in the three impact states, 92% was from non-stripper wells.

In Chapter III, a survey of current formation water disposal regulations and practices was reported for the 19 largest oil-producing states. They accounted for 99% of total production. Based on the survey, it was estimated that 22% of 490,000 wells in these states, including stripper wells, did not have their formation water reinjected into the ground in 1975. Texas, Louisiana, and Wyoming contain a large percentage of the wells not reinjecting and are more generally representative of the non-reinjecting and non-stripper production (Table V-4).

TABLE V-1

U.S. OIL PRODUCTION BY STATE

State	Annual Production and Number of Wells Producing (Dec. 31, 1975) Total U.S. and Stripper Wells						Average Daily Production Per Well for Total and Stripper Wells		Proved API Reserves as of 12/31/75
	1975 Production			1975 No. of Wells			1975 B/D		
	Stripper MB [a]	Total MB [b]	Stripper % of Total	Stripper [a]	Total [b]	Stripper % of Total	Stripper B/D [a]	Total B/D [b]	(MB)
Alabama	116.7	13,477	0.9	75	608	12.3	4.26	62.1	61,032
Alaska	-	69,834	-	-	205	-	-	947.2	10,037,262
Arizona	5.2	635	0.8	6	28	21.4	2.40	65.7	95,662
Arkansas	5,042.7	16,133	31.2	6,100	7,308	83.5	2.26	6.1	*
California	60,574.2	322,199	18.8	32,124	41,029	78.3	5.17	21.7	3,647,537
Colorado	1,953.4	38,089	5.1	881	2,450	2.1	6.07	45.1	276,066
Florida	-	41,877	-	-	143	-	-	822.4	262,539
Illinois	25,214.7	26,067	96.7	23,222	23,373	99.4	2.97	3.0	160,986
Indiana	4,031.7	4,632	87.0	4,654	4,798	97.0	2.37	2.8	22,029
Kansas	43,706.7	59,106	73.9	40,597	41,945	96.8	2.95	3.9	364,394
Kentucky	6,182.8	7,556	81.8	13,690	13,905	98.4	1.24	1.5	39,306
Louisiana	7,574.2	650,840	1.2	12,723	24,453	52.0	1.63	72.9	3,827,187
Michigan	4,760.3	24,420	19.5	3,330	3,655	91.1	3.92	17.0	93,312
Mississippi	648.8	46,614	1.4	310	2,237	13.8	5.73	56.9	231,158
Missouri	57.0	57	100.0	163	163	100.0	0.96	1.0	*
Montana	3,578.7	32,844	10.9	1,873	3,247	57.7	5.23	28.3	163,968
Nebraska	1,545.4	6,120	25.2	638	1,190	53.6	6.64	14.5	28,372
Nevada	-	115	-	-	6	-	-	42.0	*
New Mexico	11,082.5	95,063	11.6	10,274	13,715	74.9	2.96	19.3	588,110
New York	875.0	875	100.0	5,231	5,231[a]	100.0	0.46	0.5	10,024
North Dakota	929.7	20,452	4.5	569	1,994	28.5	4.48	32.2	158,245
Ohio	6,704.6	9,578	70.0	15,482	16,611	93.2	1.19	1.6	121,263
Oklahoma	72,530.6	163,123	44.5	58,736	71,516	82.1	3.38	6.2	1,239,687
Pennsylvania	3,199.0	3,199[a]	100.0	31,661	31,661[a]	100.0	0.28	0.3	48,028
South Dakota	17.9	472	3.8	9	38	23.7	5.46	37.5	1,855
Tennessee	125.6	682	18.4	133	172	77.3	2.59	11.5	1,508
Texas	126,018.3	1,221,929	10.3	89,027	160,603	55.4	3.88	20.9	10,080,035
Utah	98.2	42,301	0.2	48	1,323	3.6	5.60	96.6	208,318
Virginia	3.0	3	100.0	7	7	100.0	1.17	1.6	*
West Virginia	2,478.0	2,479	100.0	13,680	13,680[a]	100.0	0.50	0.5	31,418
Wyoming	5,107.0	135,943	3.8	2,629	9,450	27.8	5.32	41.1	877,385
Misc.									5,441
TOTAL U.S.	349,162.9	3,056,716	11.4	367,872	496,804	74.5	2.93	16.9	32,682,127

*Included in misc.

[a]Interstate Oil Compact Commission National Shipper Well Survey, December 31, 1975.

[b]U.S. Bureau of Mines Petroleum Statement; except as noted for states containing only stripper wells where the appropriate state agency stated that the I.O.C.C. data was more accurate.

SOURCE: Interstate Oil Compact Commission National Stripper Well Survey, December 31, 1975; U.S. Bureau of Mines Petroleum Statement, March 1976.

TABLE V-2

TEXAS, LOUISIANA, AND WYOMING OIL PRODUCTION - 1975

State	Stripper Wells		Non-Stripper Wells		Total	
	Production (1,000 bbls)	No. of Wells	Production (1,000 bbls)	No. of Wells	Production (1,000 bbls)	No. of Wells
Louisiana						
Onshore	7,574	12,723	282,214	15,829	289,788	23,403
Offshore	none	none	361,052	4,331	361,052	1,050
Texas						
Onshore	126,018	89,027	1,095,132	71,226	1,221,150	160,253
Offshore	none	none	779	350	779	350
Wyoming	5,107	2,629	130,836	6,821	135,943	9,450
TOTAL	138,699	104,379	1,870,013	87,052	2,008,712	191,431

SOURCE: Petroleum Statement, March 1976, U.S. Bureau of Mines; National Stripper Well Survey, December 31, 1975, Interstate Oil Compact Commission; Arthur D. Little, Inc., estimates.

TABLE V-3

PRODUCTIVITY OF ONSHORE WELLS IN TEXAS, LOUISIANA, AND WYOMING - 1975

State	Stripper Wells		Non-Stripper Wells		All Wells	
	Number of Wells	Average Productivity (bbls/day)	Number of Wells	Average Productivity (bbls/day)	Number of Wells	Average Productivity (bbls/day)
Louisiana	12,723	1.63	15,829	48.8	23,403	33.9
Texas	89,027	3.88	71,226	42.1	160,253	20.9
Wyoming	2,629	5.32	6,821	52.6	9,450	39.5

SOURCE: Petroleum Statement, March 1976, U.S. Bureau of Mines; Arthur D. Little, Inc., estimates.

TABLE V-4

REINJECTION IN TEXAS, LOUISIANA, AND WYOMING (ONSHORE)

State	Oil Production (MM bbls)	Water Production (MM bbls)	% Water Reinjected	Number of Wells	% Wells Reinjecting[a]
Louisiana	290	1,050	56%	20,328	over 50%
Texas	1,221	3,560	94%	160,253	over 90%
Wyoming	136	941	75%	9,450	over 50%
TOTAL	1,647	5,551	84%	190,031	over 85%

a. Percent of wells whose formation water is reinjected.

SOURCE: Petroleum Statement, March 1976, U.S. Bureau of Mines; Arthur D. Little, Inc., estimates.

State regulations in Texas and Louisiana allow discharge of produced formation water to brackish and tidally affected surface water. Most of the surface discharges in Texas appear to be along the Gulf Coast on or adjacent to bays and the Gulf. There are some discharges to evaporation pits. Because of the large number of bays, bayous, and marsh areas in southern Louisiana, a high percentage of the produced formation water is discharged to surface waters. In Wyoming, much of the formation water has low salt (TDS) content and the state has allowed its use in watering livestock.

As part of the project by the engineering contractor to estimate the costs of compliance with a reinjection requirement, production profiles were developed of wells not currently reinjecting their formation water in the three states. Tables V-5, V-6, V-7, V-8, and V-9 are the distributions in the states of production units over average productivity per production well and number of wells per production unit. The well populations were compiled from published reports in the states and have not been revised or updated by Arthur D. Little, Inc. The numbers of wells and their productivity are listed on Table V-10. Table V-11 lists the total remaining production of the impacted wells at current prices and production technology. The well populations were intended by the engineering contractor to include all of the wells in each of the states not currently reinjecting, to the extent this information could be determined from existing state records. The Louisiana profile may understate the number of lower production wells, but such an understatement has not been explicitly determined.

All of the potentially impacted wells are classified as "onshore" wells. However, some of the Texas and Louisiana wells are actually producing to platforms and are treated as a separate category. Only the non-stripper well portions of the on-land well populations are affected by the proposed effluent

TABLE V-5

EPA FORMATION WATER DISPOSAL ANALYSIS, REINJECTION

STATE WYOMING

AVG PROD/WELL (B/D)	PRODUCING UNIT CATEGORIES (# wells/producing unit)									
	2.	5.	9.	13.	16.	25.	35.	50.	80.	100.
11.50	2	0	4	1	0	0	[illegible]	0	1	0
12.50	6	1	1	2	[illegible]	0	0		[illegible]	1
13.50	10	2	1	1	0	0	2	0	[illegible]	[illegible]
14.50	3	1	0	0		1	0	[illegible]	[illegible]	[illegible]
15.50	4	1	0	0		1	[illegible]	[illegible]	0	0
[illegible]	20	0	1	1	1	1	0	0	0	0
25.00	27	9	5	1	0	0	1	0	0	0
35.00	23	4	0	4	0	0	0	0	[illegible]	
45.00	11	1	5	0	1	0	1	2		[illegible]
55.00	4	3	1	1	1	2	0	[illegible]		[illegible]
65.00	[illegible]	4	0	0	1	0	0	1	[illegible]	0
75.00	1	3	0	0	0	1	1	[illegible]		
85.00	[illegible]	1	0	1	0		[illegible]			
95.00	5	1	0	0	0	0	0		[illegible]	0
125.00	9	2	0	0	0	0	0	0	0	
175.00	4	0	0	0	0	0	0	[illegible]	0	[illegible]
225.00	0	0	0	0	1	0	0	0	0	0
275.00	0	0	0	0	0	0	0	0	0	0
300.00	0	0	0	0	0	0	0	0	1	0

SOURCE: Jacobs Engineering, Inc.

TABLE V-6

EPA FORMATION WATER DISPOSAL ANALYSIS, REINJECTION

STATE LOUISIANA ONSHORE

AVG PROD/WELL (B/D)	PRODUCING UNIT CATEGORIES (# wells/producing unit)									
	2.	5.	9.	13.	18.	25.	35.	50.	8[illegible].	1[illegible].
11.5	0	0	0	0	[illegible]	0	0	[illegible]	[illegible]	
12.50	0	0	0	0	0	0	0	0		
13.50	1		0	0	0	0	0	0	[illegible]	
14.50	0		0	0	0	0	0	0		[illegible]
15.50	1	0	0	0	0	0	0	0	[illegible]	
18.00	[illegible]	0	0	0	0	0	0	0	[illegible]	
25.00	4	1	0	1	0	1	0	0	1	
35.00	0	0	1	0	0	0	0	[illegible]		[illegible]
45.00	1	0	0	0	0	0	0	0	0	[illegible]
55.00	3	0	0	0	0	0	0	[illegible]	0	[illegible]
65.00	1	0	0	0	1	0	0	0	1	
75.00	1	0	0	0	0	0	0	[illegible]	1	
85.00	1	2	0	0	0	1	0	0	[illegible]	[illegible]
95.00	1	0	0	0	[illegible]	0	0	0	[illegible]	[illegible]
125.00	4	0	1	0	0	0	0	0	2	[illegible]
175.00	3	0	0	0	0	0	0	0	[illegible]	
225.00	1	0	0	0	0	0	1	0	0	[illegible]
275.00	1	0	0	0	0	0	0	[illegible]	0	[illegible]
300.00	1	0	0	0	0	0	0	0		[illegible]

SOURCE: Jacobs Engineering, Inc.

TABLE V-7

EPA FORMATION WATER DISPOSAL ANALYSIS, REINJECTION

STATE LOUISIANA OFFSHORE
(# wells/producing unit)

AVG PROD/WELL B/D	PRODUCING UNIT CATEGORIES								
	3.	9.	13.	18.	25.	35.	50.	80.	100.
.50	0	0	0	0	0	0	0	0	0
1.50	0	0	0	0	0	0	0	0	0
2.50	0	0	0	0	0	0	0	0	0
3.50	0	0	0	0	0	0	0	0	0
4.50	0	0	0	0	0	0	0	0	0
5.50	0	0	0	0	0	0	0	0	0
6.50	0	0	0	0	0	0	0	0	0
7.50	0	0	0	0	0	0	0	0	0
8.50	0	0	0	0	0	0	0	0	0
9.50	0	0	0	0	0	0	0	0	0
10.50	0	0	0	0	0	0	0	0	0
11.50	0	0	0	0	0	0	0	0	0
12.50	1	0	0	0	0	0	0	0	0
13.50	0	0	0	0	0	0	0	0	0
14.50	0	0	0	0	0	0	0	0	0
15.50	0	0	0	0	0	0	0	0	0
16.00	2	0	0	0	0	0	0	0	0
25.00	0	0	0	0	0	0	0		0
35.00	0	0	0	0	0	0	0	0	0
45.00	0	0	0	0	1	0	0	0	0
55.00	0	1	0	0	0	0	0	0	0
65.00	0	0	0	0	0	0	0	0	0
75.00	0	0	1	0	1	0	0	0	0
85.00	0	0	1	0	0	0	0	0	0
95.00	0	0	0	2	0	0	0	1	0
125.00	2	1	0	0	1	0	0	0	3
175.00	2	0	1	1	0	0	2	2	0
225.00	0	0	0	0	0	1	0	0	0
275.00	1	1	1	0	0	0	1	0	0
300.00	1	0	0	0	0	1	0	0	0

SOURCE: Jacobs Engineering, Inc.

TABLE V-8

EPA FORMATION WATER DISPOSAL ANALYSIS.REINJECTION

STATE TEXAS LAND

AVG PROD/WELL (B/D)	PRODUCING UNIT CATEGORIES (# wells/producing unit)									
	2.	5.	9.	13.	18.	25.	35.	50.	80.	100.
11.50	2	1	1	1	1	0	0	[illegible]	0	0
12.50	4	2	0	1	0	0	0	0	0	0
13.50	5	2	0	0	1	0	0	0	0	0
14.50	4	1	0	1	0	0	0	0	0	0
15.50	5	0	1	1	0	1	0	0	[illegible]	0
18.00	17	3	0	1	0	0	0	0		0
25.00	30	2	1	3	2	0	0	0	[illegible]	0
35.00	13	8	1	0	1	0	0	0	[illegible]	0
45.00	9	1	0	0	0	0	0	0	[illegible]	0
55.00	6	0	0	0	0	0	0	[illegible]		[illegible]
65.00	10	1	0	0	0	0	0	[illegible]		[illegible]
75.00	1	0	0	0	[illegible]	0	0	[illegible]		[illegible]
85.00	1	0	[illegible]	0	[illegible]	0	[illegible]	[illegible]		
95.00	0	2	0		0	[illegible]	0			[illegible]
125.00	[illegible]	0	[illegible]	0	0	0	0	[illegible]		[illegible]
175.00	3	0	0	0	0	0	1	0		[illegible]
225.00	0	0	0	0	0	0	0	0		
275.00	1	0	0	0	0	0	0	0		[illegible]
300.00	[illegible]	0	0	1	0	0	0	0		[illegible]

SOURCE: Jacobs Engineering, Inc.

TABLE V-9

EPA FORMATION WATER DISPOSAL ANALYSIS, REINJECTION

STATE TEXAS OFFSHORE

AVG PROD/WELL (B/D)	PRODUCING UNIT CATEGORIES (# wells/producing unit) 2.	5.	9.	13.	18.	25.	35.	50.	80.	100.
.50	4	2	0	0	0	0	0	0	0	0
1.50	3	1	0	0	0	0	0	0	0	0
2.50	5	1	1	0	0	0	0	0	0	0
3.50	6	0	1	0	0	0	0	0	0	0
4.50	5	0	0	0	0	0	0	0	0	0
5.50	6	1	3	1	0	0	0	0	0	0
6.50	8	0	1	0	0	0	0	0	0	0
7.50	4	1	0	0	0	0	0	0	0	0
8.50	5	0	0	0	0	0	0	0	0	0
9.50	4	1	0	0	0	0	0	0	0	0
10.50	2	0	0	0	0	0	0	0	0	0
11.50	5	1	0	0	0	0	0	0	0	0
12.50	1	0	0	1	0	0	0	0	0	
13.50	2	0	0	0	0	0	0	0	0	0
14.50	7	0	0	0	0	0	0	0	0	0
15.50	1	0	0	0	0	0	0	0	0	0
18.00	6	1	0	0	0	0	0	0		0
25.00	15	2	0	1	0	0	0	0		0
35.00	14	0	0	2	0	0	0	0	0	0
45.00	5	0	0	0	0	0	1	0	0	0
55.00	2	0	0	1	0	0	0	0	0	0
65.00	1	0	0	0	0	0	0	0	0	0
75.00	2	0	0	0	0	0	0	0	0	0
85.00	0	0	0	0	0	0	0	0		0
95.00	1	0	0	0	0	0	0	0		0
125.00	0	0	0	0	0	0	0	0	0	0
175.00	1	0	0	0	0	0	0	0	0	0
225.00	2	0	0	0	0	0	0	0	0	0
275.00	0	0	0	0	0	0	0	0	0	0
300.00	0	0	0	0	0	0	0	0	0	0

SOURCE: Jacobs Engineering, Inc.

TABLE V-10

POTENTIALLY IMPACTED PRODUCTION

State	Stripper Wells		Non Stripper Wells		All Wells	
	Number of Wells	Production (bbl's/day)	Number of Wells	Production (bbl's/day)	Number of Wells	Production (bbl's/day)
Louisiana						
on land	0	0	715	64,513	715	64,513
on platforms	2	11	1,031	156,382	1,033	156,393
Texas						
on land	824	4,744	1,108	82,761	1,932	87,505
on platforms	206	1,028	250	8,999	456	10,027
Wyoming	547	3,147	1,594	89,853	2,141	93,000
TOTAL	1,579	8,930	4,698	402,508	6,277	411,438

SOURCE: Jacobs Engineering, Inc.

TABLE V-11

POTENTIAL PRODUCTION OF IMPACTED WELLS

	Number of Wells	1975 Production (bbl's/day)	Remaining Production (MM bbl's)
Louisiana			
on land	715	64,513	281
on platform[a]	1,033	156,394	683
Texas			
on land	1,108	82,761	360
on platform[a]	456	10,027	41
Wyoming	1,594	89,853	385
Total of Selected States	4,906	403,548	1,750

a. Platform guidelines cover stripper and non-stripper wells.

SOURCE: Number of wells and production, Jacobs Engineering. Remaining production, Arthur D. Little, Inc.

limitation. Both the stripper and non-stripper platform wells are covered by the platform effluent limitation.

2. Production Cost Models

No data was available for the impact analysis about the production history and the production cost of the units found to be impacted by the proposed regulation. To make an estimate of the potential impact on these specific production units, it would have been necessary to know:

- how long the production unit had been producing;
- what the initial investment had been in drilling costs and production equipment;
- how much of that investment still needed to be depreciated against future production;
- what the production decline rate had been in the past and what it could be expected to be in the future;
- what the annual operating costs are and how they are expected to change with declining production; and
- what the overhead charges are to the specific production unit.

In the absence of this information, production cost models developed by the Bureau of Mines for the states analyzed (Information Circular 8561, 1972) were modified and updated to 1975.

To assure a conservative analysis, the operating costs per producing well were assumed not to decrease as the well's production declined. In reality, direct operating expenditures per well will be reduced as the production unit's overall production declines.

The capital costs and operating costs for a 10-well production unit are shown in Table V-12. The price and tax assumptions used in the economic impact analysis are shown in Table V-13. Given the uncertainty about future oil prices, the analysis was done using what can be considered a high and low price scenario. The low price scenario, resulting in a high impact estimate, assumed continued regulation of all oil produced from wells with more than 10 B/D at the lower tier wellhead price of $5.25 per barrel and all stripper well oil (i.e., oil from wells producing at an average of less than 10 B/D per well) at the wellhead price of $11.28 per barrel.

Since stripper well oil may be deregulated and allowed to sell at world prices close to $12.50 per barrel, this price scenario can be regarded as potentially overstating the economic impacts.

The high price scenario, resulting in lower impact estimates, assumed continued price regulations with lower and upper tier prices, as under the low price scenario, and an annual increase in real prices of 3% per year (the so-called economic incentive factor which at present is intended to apply until the end of 1979, the last year covered by present price regulations).

In order to make the impact analysis conservative, none of the production was assumed to qualify for depletion allowance, implying that all producers are producing more than 2,000 barrels per day. An investment credit of 7% was assumed to apply to the investment in required pollution control equipment. Depreciation of original capitalized investment and expenditures in lease equipment and producing wells, and of the investment in the pollution control equipment,was calculated using the unit of production method.

TABLE V-12

CAPITAL AND OPERATING COSTS FOR 10-WELL LEASES

(1975, $1,000's)

State	Total Development Costs	Annual Operating Costs
Louisiana		
on land	1,657.4	80.39
near shore platforms	2,094.2	110.88
Texas		
on land	1,520.0	78.54
near shore platforms	1,956.7	100.10
Wyoming	1,785.4	139.57

SOURCE: Information Circular 8561, U.S. Bureau of Mines updated to 1975 by Arthur D. Little, Inc.

TABLE V-13

OIL PRICE AND TAX ASSUMPTIONS

	Price[1] Old Oil	Price[1] New Oil	Fed. Tax Rate	Investment[2] Credit	Royalty	Severance and other Taxes
Louisiana, on land	5.25	11.28	0.48	0.07	.125	.13
Louisiana, near shore platforms	5.25	11.28	0.48	0.07	.125	.13
Texas, on land	5.25	11.28	0.48	0.07	.125	0.091
Texas, near shore platforms	5.25	11.28	0.48	0.07	.125	0.091
Wyoming	5.25	11.28	0.48	0.07	.125	0.067

(1) In the analysis it was, conservatively, assumed that all production from wells with average production of more than 10 b/d qualified as old oil ($5.25/B) and that production from wells with an average of less than 10 b/d would be sold at a wellhead price of $11.28/B.

(2) An investment credit of 7% was assumed to apply to the investment in the required pollution abatement equipment.

SOURCE: Arthur D. Little, Inc. estimates

The potentially impacted production units were assumed to continue using the production equipment found in place in 1975. In other words, it was assumed that producers would not change to secondary or tertiary recovery in the future and get higher total production. Production was assumed to continue declining relative to 1975 levels at a constant annual decline rate. Values from 8%/year to 15%/year were used.

No income credits were given for associated gas production, and the cost of capital was said to be the same for all producers. A low estimate of 10% and a high estimate of 15% were used in the analysis. The analysis was done in terms of constant 1975 dollars, with no relative cost inflation allowed.

VI. ECONOMIC IMPACTS

1. Summary

The economic impact on oil production in Texas, Louisiana, and Wyoming of the effluent limitations on produced formation water was estimated using the methodology outlined in Chapter IV. Table VI-1 shows that the states included in the impact analysis have:

- Forty-two percent of the total estimated number of onshore[1] producing wells in 1975 producing more than 10 B/D per well;
- Seventy-one percent of the total estimated crude oil production onshore from wells in 1975 producing more than 10 B/D per well;
- Forty-seven percent of total proven U.S. resources in 1975 or sixty-seven percent of the U.S. reserves in 1975 exclusive of the 10 billion barrels present in Prudhoe Bay, Alaska.

The three impact states may have as many as 24,000 wells whose formation water is not currently reinjecting, including stripper wells. These wells may be 70% of the currently non-reinjecting wells in the 17 largest oil-producing states, excluding Illinois, which has predominantly stripper wells. Their non-stripper production whose brine is not currently reinjected is estimated to be 72% of the total U.S. onshore non-stripper production whose brine is not reinjected.

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[1] Including wells producing from platforms located within the coastal zone, such as platforms in coastal marshes and estuaries in Louisiana and Texas.

TABLE VI-1

PRODUCTIVE CAPACITY, API PROVEN RESERVES AND NUMBER OF ONSHORE NON-STRIPPER WELLS COVERED BY THE IMPACT ANALYSIS

	Number of Onshore Non-Stripper Wells[a] (Thousands)	Onshore Non-Stripper Production[a] (Millions bbl's)	API Proven Reserves[b] (Billions of Barrels)
Louisiana	7.6	282.2	3.8
Texas	71.2	1,095.1	10.1
Wyoming	6.8	130.8	0.9
Total, Impact States	85.6	1,508.1	14.8
Total U.S.	130.5	2,206.3	32.7

a. As of December 31, 1975.

b. Includes offshore reserves.

SOURCES: API and BOM statistics for 1975 oil reserves, producing wells and production, Arthur D. Little, Inc., estimates.

The sum of the estimated impacts on oil production in the three states is shown on Table VI-2, while the state estimates are shown on Tables VI-3, VI-4, and VI-5. The primary results are summarized as follows:

- A requirement to reinject formation water from existing near-shore platforms would result in the closure of about 2% of the Louisiana platforms and 64% of the Texas platforms. An effluent treatment rather than a reinjection requirement would substantially reduce the number of well closures.
- The reinjection requirement is not expected to close any on-land, non-stripper wells in Louisiana and Texas, but could close as many as 144 wells in Wyoming.
- The investment required to install reinjection equipment in the three states, including platforms, is $80 million. It is estimated that the total U.S. requirement is roughly $110 million. This level of investment spread over several years is modest compared to $3-5 billion projected as yearly capital expenditures by the industry on onshore oil and gas production.
- The reinjection requirement would result in approximately 32 million barrels of foregone production in the three states as a result of well closures in 1977 and shorter well lives as a result of higher operating costs. The foregone production is 1.8% of the projected remaining lifetime production of the impacted wells, assuming a 12% decline rate and current price regulations. The total is 0.2% of 1975 API proven reserve estimates for the three states.
- The average increase in production costs for the three states would be $.34 per barrel of affected oil as a result of the reinjection requirement. Operating costs would increase by about $.06 per barrel.

TABLE VI-2

SUMMARY OF RESULTS

RANGE OF LIKELY IMPACTS FOR SELECTED STATES[a]

	Reinjection			Alternative Disposal		
	Min	Likely	Max	Min	Likely	Max
Number of Wells Shut In	290	456	493	120	290	377
Average Cost Increase for Directly Impacted Producers (¢/BBL)	28	34	65	18	21	30
Required Investment (Millions of 75$)	75.0	80.0	140.0	35.0	40.0	50.0
(Total U.S.)[b]	(105)	(110)	(190)	(50)	(55)	(70)
Percent of State Producing Wells Forced to Shut In[c]	0.0	0.53	0.58	0.0	0.34	0.58
Percent of State Productive Capacity Lost[c]	0.0	0.18	0.22	0.0	0.09	0.15
Percent of State API Proven Reserves Lost[c,d]	0.0	0.22	0.39	0.0	0.14	0.24

a. Texas, Louisiana, Wyoming

b. Based upon the estimated ratio of non-stripper oil production in selected states whose brine is not reinjected to total U.S. onshore non-stripper production whose brine is not reinjected: 72%.

c. Impacts relative to total number of wells, production, and reserves in the states covered by the regulation.

d. Offshore reserves included in state total.

SOURCE: Arthur D. Little, Inc., estimates

2. Base Case Results for Selected States

The impact of the proposed regulation is significantly different for each of the three states. The differences are explained by differences in the average number of wells per production unit, the average daily production per well of the production units, the production costs and the compliance costs in each state.

For example, a relatively large number of the Texas platform production units have wells with a low average well productivity. Given the relatively high production costs for these units and the relatively high compliance costs, a very high percentage of non-complying wells will have to be shut in (64% in the case of reinjection and 24% in the alternative disposal case) and average costs per barrel for those production units, which will not have to shut in, will increase significantly (by $1.42/B in the case of reinjection and by $0.94/B in the alternative disposal case).

The projected well closures for on-land wells are higher for Louisiana and Texas, given the treatment requirement, than the reinjection requirement. These results reflect the engineering contractor's estimate that the capital costs for the treatment system are higher than the reinjection system for smaller leases. For larger producers, the reinjection system was estimated to be more expensive and, thus, the total capital costs for compliance with the reinjection requirement were higher than the treatment requirement (Table VI-4).

An estimate was made of the capital investment necessary to bring all impacted wells into compliance under the assumption that the producers raised

TABLE VI-3

ESTIMATED WELL CLOSURES AND PRODUCTION LOSSES

(Base Case)

	Number of Wells Closed[a]	Percent of Impacted Wells Closed[a]	Wells Closed as a Percent of All Wells Covered by Regulation[a]	Production Foregone[b] (MM bbl's)		Foregone Production As a Percent of Potential Production by Impacted Wells[b]	Foregone Production As a Percent of Total State API Reserves[c]
				Well Closure	Shortened Well Life		
Louisiana, on land							
Reinjection	0	0.0%	0.0%	0	1.1	0.4%	0.03%
Treatment	4	0.6	0.03	0.1	0.8	0.3	0.02
Louisiana, on platform							
Reinjection	23	2.2	0.1	1.2	5.1	0.9	0.2
Treatment	2	0.2	0.01	0	1.4	0.2	0.04
Texas, on land							
Reinjection	0	0.0	0	0	1.9	0.5	0.02
Treatment	30	2.7	0.004	0.9	1.8	0.8	0.03
Texas, on platform							
Reinjection	291	64	0.4	10.5	0.6	27	0.1
Treatment	110	24	0.15	1.3	0.5	4.4	0.02
Wyoming							
Reinjection	144	9	2.1	6.2	5.2	3.0	1.3
Treatment	144	9	2.1	6.2	5.7	3.0	1.3
Total							
Reinjection	456	9	0.5	17.9	14.0	1.8	0.2
Treatment	290	6	0.3	8.5	10.2	1.1	0.1

a. Wells closed rather than brought into compliance with a reinjection requirement.
b. Production lost by immediate well closures plus shorter well life due to higher operating costs.
c. Offshore reserves excluded.

SOURCE: Arthur D. Little, Inc.

TABLE VI-4

ESTIMATED COST OF COMPLIANCE WITH REINJECTION AND TREATMENT REQUIREMENTS

(Base Case)

	Investment Requirement ($MM)	Increased Operating Cost ($MM)	Increased Operating Cost ($/bbl)	Increase in Total Production Costs[a] ($/bbl)
Louisiana, on land				
Reinjection	6.05	.82	.04	.22
Treatment	3.72	.79	.04	.16
Louisiana, on platform				
Reinjection	38.4	2.89	.05	.48
Treatment	8.6	1.15	.02	.12
Texas, on land				
Reinjection	11.5	2.03	.07	.31
Treatment	10.5	2.18	.08	.31
Texas, on platform				
Reinjection	5.3	.35	.19	1.43
Treatment	4.5	.63	.20	.94
Wyoming				
Reinjection	18.2	1.99	.07	.34
Treatment	11.2	2.27	.08	.28
Total				
Reinjection	80	8.1	.06	.34
Treatment	39	7.0	.05	.21

a. Present value of compliance costs averaged over total remaining production.

SOURCE: Arthur D. Little, Inc.

TABLE VI-5

COST OF COMPLIANCE IF PRODUCERS PASS ON COSTS

(Base Case)

	Required Investment ($MM)	Increased Operating Cost ($/bbl)	Average Required Price Increase ($/bbl)
Louisiana, on land			
Reinjection	6.1	0.4	.20
Treatment	3.8	0.4	.17
Louisiana, on platform			
Reinjection	41.3	.06	.44
Treatment	8.7	.02	.12
Texas, on land			
Reinjection	11.5	.07	.32
Treatment	11.5	.07	.34
Texas, on platform			
Reinjection	50.1	.96	6.89
Treatment	7.2	.30	1.32
Wyoming			
Reinjection	23.6	.08	.51
Treatment	15.7	.10	.43
Total			
Reinjection	132.5	NA	NA
Treatment	46.8	NA	NA

<u>SOURCE</u>: Arthur D. Little, Inc.

prices sufficient to pay for the abatement equipment and no wells were shut in. The total capital requirement for reinjection facilities in the three states is about \$130 million and \$45 million for treatment equipment (Table VI-5).

The impact analysis results presented in Tables VI-3, VI-4, and VI-5 are for the "Base Case" set of assumptions. These included a production decline rate of 12% per year, a cost of capital of 10%, and continued price regulation at \$5.25 per barrel of non-stripper oil and \$11.28 per barrel of stripper well oil.

3. Sensitivity Tests and Range of Impacts

There is considerable uncertainty about future crude oil prices, the cost of capital and annual production decline rates. To understand these uncertainties, sensitivity tests established the ranges within which the different impacts can be expected to fall with a high confidence level.

The results of the sensitivity tests are shown in Table VI-6 for changes in the annual production decline rate and in Table VI-7 for changes in the cost of capital and future oil prices.

Graphing of the results of the sensitivity analysis displayed the minimum, likely and maximum values for the six impact indicators measured. Figure VI-1 shows the reinjection requirement case and Figure VI-2 shows the alternative disposal case. For both the reinjection requirement and the alternative disposal case, it was found that:

- The regulation would result in a maximum impact if:
  - producers cannot pass on all costs;
  - future real upper tier and lower tier crude oil prices do not change relative to 1976 values;

TABLE VI-6

SUMMARY OF SENSITIVITY TESTS FOR SELECTED STATES;

CHANGES IN DECLINE RATE

	SCENARIO 1 (Base Case) Producers Absorb All Costs						SCENARIO 2 Producers Pass on All Costs					
	-Reinjection-			Alternative -Disposal-			-Reinjection-			Alternative -Disposal-		
	8%	12%	15%	8%	12%	15%	8%	12%	15%	8%	12%	15%
Number of Wells Shut-In	400	456	493	178	290	371	0	0	0	0	0	0
Percent of Total Producing Wells	0.47	0.53	0.58	0.21	0.34	0.43	0	0	0	0	0	0
Productive Capacity Loss (bbls/day)	5889	7157	7840	1851	3747	4686	0	0	0	0	0	0
Percent of Total Productive Capacity	0.14	0.18	0.19	0.04	0.09	0.11	0	0	0	0	0	0
Potential Production Loss (million of bbls)	46.8	32.4	26.7	27.6	20.9	17.6	0	0	0	0	0	0
Percent of 1975 API Proven Reserves	0.30	0.22	0.17	0.18	0.14	0.11	0	0	0	0	0	0
Required Investment (millions of 75$)	85.3	82.2	80.1	44.0	40.2	39.0	136.1	135.5	134.9	49.4	49.3	49.1
Average Increase of Production Cost (¢/bbl)	30	34	37	19	21	22	43	49	54	22	25	27

SOURCE: Arthur D. Little, Inc., estimates

TABLE VI-7

SUMMARY OF SENSITIVITY TESTS FOR SELECTED STATES;

BASE CASE (BC)[a], HIGH PRICE (HP)[b], HIGH COST OF CAPITAL (CC)[c]

	SCENARIO 1 Producers Absorb All Costs						SCENARIO 2 Producers Pass on All Costs					
	Reinjection			Alternative Disposal			Reinjection			Alternative Disposal		
	BC	HP	CC	BC	HP	CC	BC	HP	CC	BC	HP	CC
Number of Wells Shut-In	456	390	475	290	120	377	0	0	0	0	0	0
Percent of Total Producing Wells	0.53	0.46	0.55	0.34	0.14	0.44	0	0	0	0	0	0
Productive Capacity Loss (bbls/day)	7157	5531	7733	3747	890	4827	0	0	0	0	0	0
Percent of 1975 Productive Capacity	0.18	0.13	0.19	0.09	0.02	0.12	0	0	0	0	0	0
Required Investment (Millions of 75$)	80.0	85.9	79.1	38.5	42.5	37.0	132.6	133.3	133.3	46.9	47.4	47.4
Average Increase of Production Cost (¢/bbl)[a]	34.0	35.0	38.0	21.0	25.0	22.0	49.0	50.0	57.0	25.0	27.0	27.0
Potential Production Lost (MMB)	31.5	18.5	32.9	18.7	5.6	21.1	0	0	0	0	0	0
Percent of 1975 API Proven Reserves[d]	0.21	0.13	0.22	0.13	0.04	0.14	0	0	0	0	0	0

a. $5.25/BBL for non-stripper well oil, $11.28/BBL for stripper well oil, cost of capital of 10%/yr., production decline rate of 12%/yr.

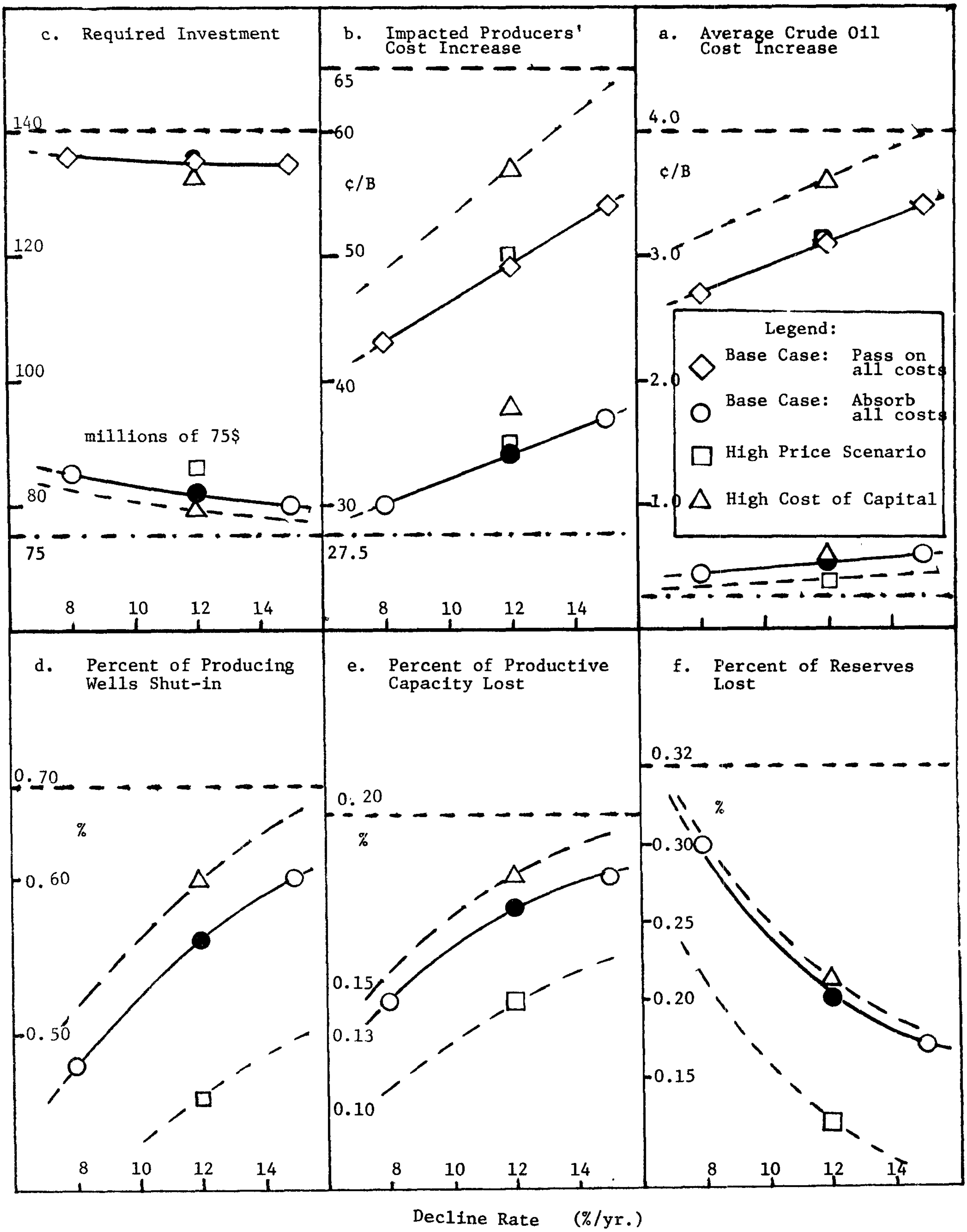
b. Real annual increase in lower ($5.25/B) and upper tier ($11.28/B) of 3%/yr.

c. Cost of capital of 15%/yr.

d. Includes offshore reserves.

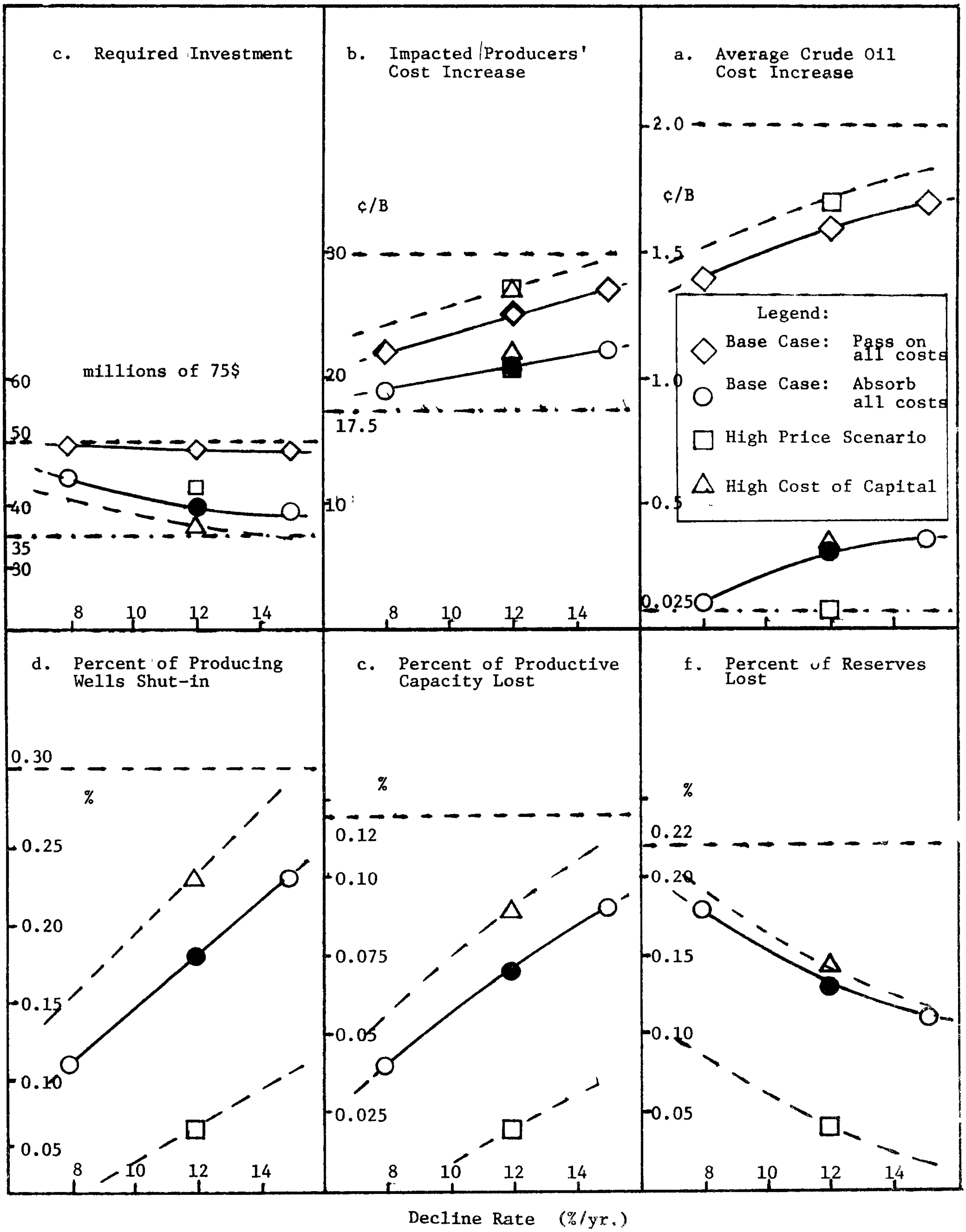
SOURCE: Arthur D. Little, Inc., estimates

FIGURE VI-1. Reinjection Requirement: Sensitivity Tests



SOURCE: Arthur D. Little, Inc., estimates

FIGURE VI-2. Alternative Disposal Requirement: Sensitivity Tests



SOURCE: Arthur D. Little, Inc., estimates

- production decline rates are 15%/year; and
- the cost of capital is 15%/year.

- The regulation would result in a minimum impact if:
  - producers can pass on all costs;
  - future real upper tier and lower tier crude oil prices escalate at 3%/year relative to 1976 values;
  - production decline rates are 8%/year; and
  - the cost of capital is 10%/year.

Figure VI-1a,b and Figure VI-2a,b show that required cost increases are more sensitive to changes in the cost of capital (15% versus 10% for the base case) than to changes in the assumed future values of oil prices (3% annual escalation versus level lower and upper tier prices of respectively $5.25 and $11.28 per barrel for the base case).

However, well shut-ins, loss in productive capacity and loss of reserves are more sensitive to changes in price than to changes in cost of capital (see Figure VI-1d,e,f and Figure VI-2d,e,f). Only the estimates of required investment turned out to be rather insensitive to changes in the production decline rate.

VII. LIMITS OF THE ANALYSIS

1. Data Limitations

The relevance of the economic impact analysis results is inherently limited by data inputs to the analysis. The major data categories in which problems could exist are the production costs, the costs of compliance, and the production profiles.

Costs of Production

The production cost models are based on Bureau of Mines models developed four years ago. The components of the models have been updated to 1975 using various escalators. Changes in production practices, technology, and inflation can alter the representativeness of the models. In addition, the models are intended to be broadly representative of production in an area, but they are being used to analyze specific leases and particularly less economical leases.

Costs of Compliance

The costs of compliance were developed by the EPA's engineering contractor. The costs were based on a field survey of reinjection and treatment costs in the three states. While the costs have not been reviewed in detail, some potential problems have been noted. There is great variability among the sample costs,suggesting a lack of consistent definition of treatment versus production equipment and consistency among production characteristics. In addition, there were a limited number of smaller volume data points which made the costs for the most vulnerable wells least reliable.

Relative to other cost studies, the compliance costs for high volume wells seems reasonable, while the costs for the low volume wells could be high or low.

Production Profiles

EPA's engineering contractor compiled data on non-complying production in the states under examination. The profiles were developed from publicly available records in the state oil and gas agencies. There remains a question as to the completeness of the Louisiana profile. It is possible that the on-land population of wells not currently reinjecting formation water is larger (perhaps substantially larger) than used in the analysis. Initial uncertainty on EPA's part about the definition of no discharge and the possibility that state records do not accurately reflect formation water discharges to ponds and brackish waters is the basis for the potentially understated population.

A primary uncertainty with the production profiles generally is the degree to which producers not now reinjecting are treating their effluent and therefore how much of the population would not be in compliance with a treatment requirement. The engineering contractor made the assumption that producers not now reinjecting had no treatment equipment and thus faced the full treatment compliance costs. This assumption probably overstates the impact of a treatment regulation.

2. Methodology Limitations

The main limitations of the methodology used in this analysis are:

- the assumption that all impacted producers will behave in the same manner;
- the assumption that producers will make their investments individually and not try to reduce their costs by combining in larger disposal units;

- the use of uniform decline rates to project production from potentially impacted production units; and
- the use of average production economics to analyze the economic impact on economically marginal production units.

This latter limitation is illustrated by Table VII-1, where it is shown what percentage of the number of potentially impacted units would be uneconomical to produce in 1975 according to the average production costs assumed in the analysis.

TABLE VII-1

PERCENT OF NON-COMPLYING WELLS WHICH
ARE SUBECONOMICAL ACCORDING TO PRODUCTION MODEL

	Total number of non-complying wells	Number of "subeconomical" wells(1)	
Louisiana			
on-land	715	0	(0%)
near shore platforms	1,033	0	(0%)
Texas			
on-land	1,932	30	(1.60%)
near shore platforms	456	29	(6.4%)
Wyoming	2,141	67	(3.1%)

(1) Production units would immediately shut in if the average production costs used in the analysis are applied. This indicates that at least the average operating cost estimates used in the analysis are too high for some non-complying production units and as such might result in an over-estimation of the potential impact.

SOURCE: Arthur D. Little, Inc.

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