ECONOMIC IMPACT ANALYSIS OF PROPOSED EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS OF PERFORMANCE FOR THE OFFSHORE OIL AND GAS INDUSTRY

Prepared for:

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PREFACE

This document is an economic impact analysis prepared in support of the 1991 reproposal of effluent limitations guidelines and standards of performance for drilling and production wastes for the offshore oil and gas industry. The report analyzes the economic impact of alternative regulatory options that are discussed in the reproposal.

The report was prepared for the U.S. Environmental Protection Agency, Office of Water, Office of Water Regulations and Standards, Analysis and Evaluation Division, Economic Analysis Branch. The analysis was prepared by Eastern Research Group, Inc. (ERG), Arlington, Massachusetts, under contracts 68-03-3548 and 68-C0-0080.

ERG's project manager for this effort was Maureen F. Kaplan. Work on this report was carried out by her, Eric M. Sigler, Jeff Cantin, and Mark Lennon. David Meyers served as expert reference and quality control reviewer of the analytical content of the analysis. Ann M. Watkins, economist with the Economic Analysis Branch, was the task manager. The analysis was completed in February 1991.

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EXECUTIVE SUMMARY

ES.1 BACKGROUND

The EPA proposed effluent limitations guidelines and standards for the offshore segment of the oil and gas industry on August 26, 1985. The proposed regulations covered produced water, drilling fluids, drill cuttings, produced sand, deck drainage, and well treatment fluids, as well as sanitary and domestic wastes discharges. A Notice of Data Availability and Request for Comments relating to the discharge of drilling fluids and drill cuttings was published on October 21, 1988.

In light of new information and data collected since 1985, the Agency has decided to repropose effluent limitations guidelines for the offshore oil and gas industry. This report evaluates the cost and economic impacts of BAT and NSPS regulatory options for drilling fluids, drill cuttings, and produced water.

ES.2 DESCRIPTION OF OFFSHORE OIL AND GAS INDUSTRY

The offshore oil and gas industry searches for and produces oil and gas in areas off the nation's coasts. Most existing production is offshore Texas, Louisiana, California, and Alaska. Several other offshore areas, including the waters off Alabama and Florida and Georges Bank in the Atlantic, have been explored to a lesser extent.

The industry leases areas to be developed from states (for areas within 3 miles from shore)[1] or the Federal government. Exploration wells are drilled to determine the presence of hydrocarbons on a leased tract. Development wells and production platforms are installed where hydrocarbons are found. Offshore oil and gas production accounted for 14.4 percent of United States oil production and 27.3 percent of natural gas production in 1986.

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[1]State waters in Texas and Florida include areas within 3 leagues or about 10.4 statute miles of shore.

ES.3 OVERVIEW OF REGULATORY APPROACHES

ES.3.1 Drilling Fluids and Drill Cuttings

Five options for BAT and NSPS were developed for the control of drilling fluids and drill cuttings. The following requirements are included in some combination in the various options:

- No discharge of drilling fluids or drill cuttings.
- No discharge of diesel oil in detectable amounts or no discharge of drilling fluids and drill cuttings associated with oil-based drilling fluids.
- No discharge of "free oil" as measured by the static sheen test.
- Toxicity limitation as measured by a 96-hour LC_{50} test.
- Limitations on cadmium and mercury.
- Zero discharge drilling fluids and drill cuttings based on water depth or distance from shore. The zero discharge requirement is presumed to be met by barging the fluids and cuttings to shore for disposal. The August 26, 1985 proposal based part of those requirements on water depth, not distance from shore.

These requirements have been combined into five regulatory options, which are the focus of the economic impact analysis:

- **Zero Discharge** - all drilling fluids and drill cuttings are barged to shore for treatment and disposal.
- **4-Mile Barge; 1,1 Other** - fluids and cuttings from wells drilled within 4 miles of shore are barged to shore for disposal. Fluids and cuttings from wells beyond 4 miles of shore must meet a 1,1 mg/kg limit on mercury and cadmium content in the discharged fluid, pass the toxicity test, substitute mineral oil for diesel oil, and pass the static sheen test.
- **4-Mile Barge; 5,3 Other** - fluids and cuttings from wells drilled within 4 miles of shore are barged to shore for disposal. Fluids and cuttings from wells beyond 4 miles of shore must meet a 5,3 mg/kg limit on cadmium and mercury content (respectively) in the stock barite, pass the toxicity test, substitute mineral oil for diesel oil, and pass the static sheen test.
- **1,1 All** - all fluids and cuttings must meet a 1,1 mg/kg limit on mercury and cadmium content in the discharged fluids, pass the toxicity test, substitute mineral oil for diesel oil, and pass the static sheen test.
- **5,3 All** - all fluids and cuttings must meet a 5,3 mg/kg limit on cadmium and mercury content (respectively) in the stock barite, pass

the toxicity test, substitute mineral oil for diesel oil, and pass the static sheen test.

The above options, though slightly different in name, are the same as those discussed in the preamble to this regulation. Other options, based on water depth, were also considered. These other options are discussed in other technical support documents, such as the Development Document, and preliminary analyses are contained in the record for the rulemaking.

ES.3.2 Produced Water

Two technologies are evaluated for the treatment and discharge and to achieve a zero discharge of produced water:

- Filtration and discharge.
- Injection.

These options are also combined with a 4-mile boundary to create three regulatory options for consideration in this report:

- **Zero Discharge** - all produced water is injected.
- **All Filter** - all produced water is filtered and discharged at the offshore facility.
- **4-Mile Filter; BPT Other** - produced water from facilities within 4 miles of shore is filtered and discharged at the offshore facility while other facilities must meet BPT requirements.

Other options considered based on better BPT treatment, reinjection with a specified distance and filtration beyond that distance, and various shallow/deep consideration were evaluated previously. Material concerning these other options can be found in the record for this rulemaking.

Each requirement is described more fully in Section One. Two sets of cost assumptions were investigated for the produced water treatment and zero discharge options as a focus for this report. The first set, based on the use of membrane filter technology, reflects recent developments in this technology, its use in the oil and gas industry, and the reduction in platform space required for the equipment. The new equipment is assumed to fit in the available space without requiring platform additions. The second set of costs, based on granular filter technology, assumes that platform additions are necessary to accommodate the required pollution control equipment, and assumes a factor to cover costs of transportation of the equipment to the offshore location and other related expenses. Two of the regulatory packages analyzed in this report assume membrane filter costs while four assume granular filter costs. More detail on the cost basis for both granular and membrane filtration technology is available in the proposed rulemaking Development Document.

ES.3.3 Combinations of Selected Regulatory Options

The Agency selected six "packages" of regulatory options for detailed economic impact analysis. Each package has an option for:

- Drilling fluids and drill cuttings (combined BAT and NSPS).
- BAT produced water.
- NSPS produced water.

Table ES-1 summarizes the packages.

ES.4 ECONOMIC METHODOLOGY OVERVIEW

The economic impact analysis methodology is summarized in Figure ES-1. There are eight major parts in the economic analysis:

- Definition of model projects.
- Development of industry activity projections.
- Impact of BAT and NSPS costs on model projects.
- Total effluent guidelines costs for the offshore oil and gas industry.
- Impact of effluent guidelines on the offshore oil and gas industry.
- Potential impact of BAT and NSPS costs on production.
- Secondary impacts of effluent guidelines costs.
- Small business impacts of effluent guidelines costs.

Figure ES-1 summarizes the major inputs and outputs for each part of the analysis.

TABLE ES-1

SUMMARY OF REGULATORY PACKAGES

Regulatory Package	Effluent	Effluent Control Option
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	4-Mile Filter; BPT Other
	Produced Water - NSPS	4-Mile Filter; BPT Other
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	Zero Discharge
	Produced Water - NSPS	Zero Discharge
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	All Filter
	Produced Water - NSPS	All Filter
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	All Filter - Membrane
	Produced Water - NSPS	All Filter - Membrane
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	BPT All
	Produced Water - NSPS	BPT All
F**	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	4-Mile Filter; BPT Other - Membrane
	Produced Water - NSPS	4-Mile Filter; BPT Other - Membrane

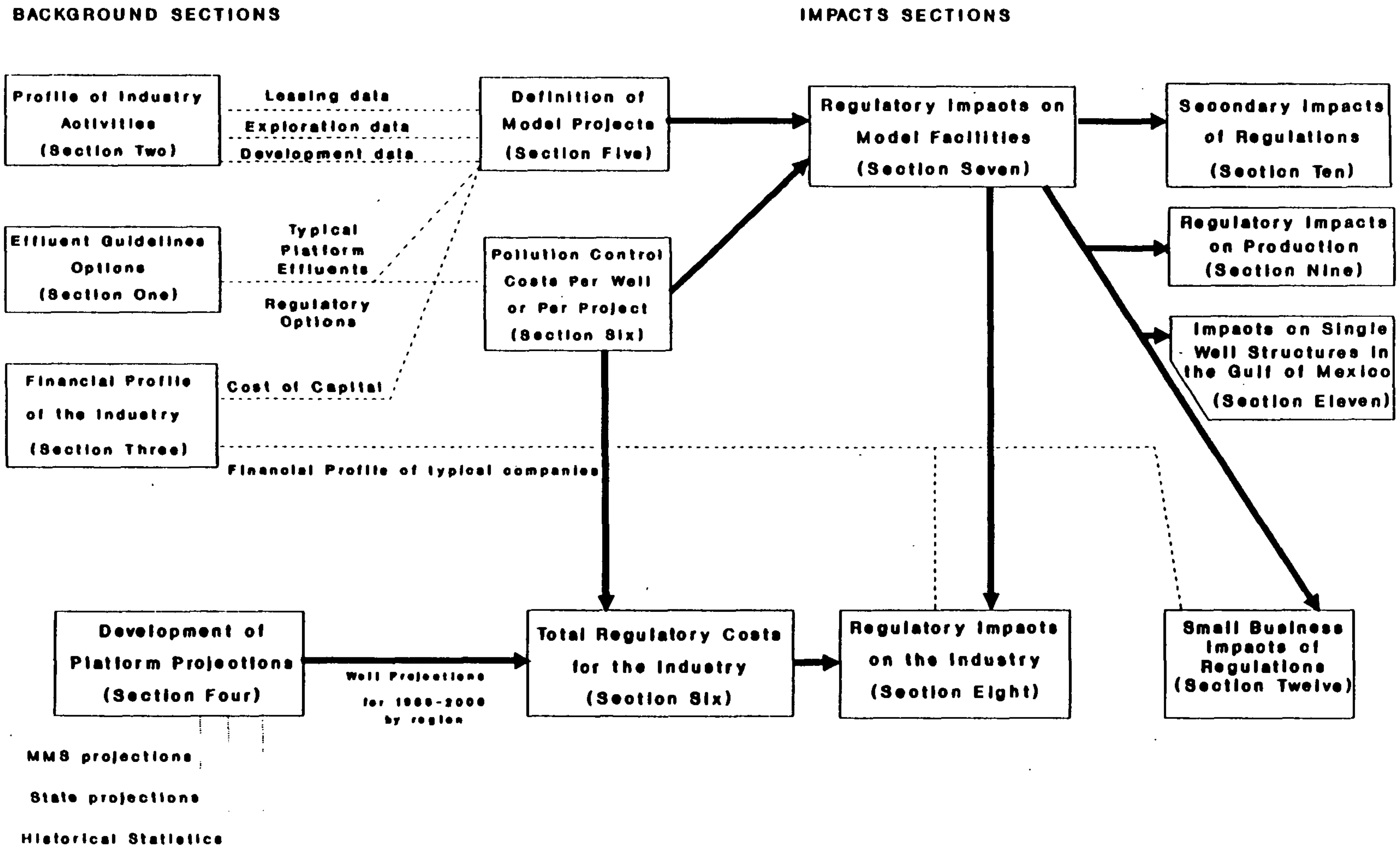
* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

** Selected Package.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology.

Source: Industrial Technology Division, U.S. Environmental Protection Agency.

FIGURE ES-1
Economic Methodology Overview



ES.5 MODEL PROJECTS

To analyze the cost and impact of effluent guidelines regulations, 34 model projects are defined. These projects account for a diversity of platform size (i.e., number of wellslots), geographic location, and production type encountered in offshore areas. Table ES-2 summarizes the characteristics of the model projects. The geological and economic features of the model projects are defined based on the literature and on industry contacts and are described in detail in Section Five. It is assumed that the wells drilled in these offshore projects use a water-based drilling fluid for the 0 to 10,000-ft depth range and an oil-based fluid in the 10,000 to 14,000-ft depth range.

ES.6 INDUSTRY ACTIVITY PROJECTIONS

Four alternative projections of industry drilling and production activity are formulated for the period 1986-2000 to assess the cost of the regulations. The projections vary according to the level of development as well as the price of oil. Under the most reasonable projections ($21/bbl with restricted development[2]), an average of 759 wells are drilled per year. These projections are based on projected production estimates for 1986-2000 developed by the Minerals Management Service and past activity levels in Federal and State waters. A total of 766 projects or facilities are projected for the entire 1986-2000 period. For comparison, the $21/bbl - unrestricted development scenario projects an average of 978 wells per year and a total of 851 facilities during the 1986-2000 time period.

ES.7 POLLUTION CONTROL COMPLIANCE COSTS

The regulatory costs were developed by the Industrial Technology Division, U.S. Environmental Protection Agency, Washington, D.C. and are described in the development document for the proposed rule. Table ES-3 presents the annualized cost for each of the six regulatory packages. In the year 2000, total annualized costs range from $30 to $1,081 million (restricted

[2]The preamble to the proposed rule discusses "constrained" and "unconstrained" development. These terms correspond to the "restricted" and "unrestricted" development scenarios, respectively, discussed in this document.

TABLE ES-2

DISTRIBUTION OF OIL, OIL/GAS, AND GAS PRODUCING PLATFORMS BY REGION AND SIZE

REGION AND WELLSLOT SIZE	PRODUCTION TYPE OIL	OIL/GAS	GAS	COMMENTS
Gulf 1a[a]	Yes	Yes	Yes	
Gulf 1b[a]	Yes	Yes	Yes	
Gulf 4	Yes	Yes	Yes	
Gulf 6	Yes	Yes	Yes	
Gulf 12	Yes	Yes	Yes	
Gulf 24	Yes	Yes	Yes	
Gulf 40	Yes	Yes	No	No gas-only platforms among large Gulf platforms.
Gulf 58	Yes	Yes	No	No gas-only platforms among large Gulf platforms.
Atlantic 24	No	Yes	Yes	
Pacific 16	No	Yes	Yes	
Pacific 40	No	Yes	No	No gas-only platforms among large Gulf platforms.
Pacific 70	No	Yes	No	No gas-only platforms among large Gulf platforms.
Cook Inlet 12/24	No	Yes	Yes[b]	
Beaufort Sea 48				
- Gravel island	Yes	No	No	No infrastructure for gas delivery.
- Platform	Yes	No	No	No infrastructure for gas delivery.
Norton Basin 34	Yes	No	No	No infrastructure for gas delivery.
Navarin 48	Yes	No	No	No infrastructure for gas delivery.

Source: ERG model project configurations based on typical projects reported in the Department of the Interior Mineral Management Service platform inspection system, complex/structure database, and the literature.

[a]The Gulf 1a shares production equipment with three other single-well stuctures while the Gulf 1b has its own production equipment.

[b]The gas-only case is modeled as 12 wells.

TABLE ES-3

COMBINED COST OF SELECTED REGULATORY PACKAGES
$MILLIONS, 1986 DOLLARS

$21/bbl

Regulatory Package	Effluent	Effluent Control Option	Annualized Cost in the Year 2000: Restricted	Unrestricted
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	4-Mile Filter; BPT Other	$41	$41
	Produced Water - NSPS	4-Mile Filter; BPT Other	$16	$27
	Combined Cost		$88	$118
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	Zero Discharge	$845	$845
	Produced Water - NSPS	Zero Discharge	$206	$275
	Combined Cost		$1,081	$1,170
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	All Filter	$480	$480
	Produced Water - NSPS	All Filter	$95	$128
	Combined Cost		$605	$657
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	All Filter - Membrane	$151	$151
	Produced Water - NSPS	All Filter - Membrane	$62	$81
	Combined Cost		$242	$282
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	BPT All	$0	$0
	Produced Water - NSPS	BPT All	$0	$0
	Combined Cost		$30	$50
F**	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	4-Mile Filter; BPT Other - Membrane	$13	$13
	Produced Water - NSPS	4-Mile Filter; BPT Other - Membrane	$11	$17
	Combined Cost		$54	$80

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

** Selected Package.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology.

Entries may not sum due to independent rounding.

Source: ERG estimates.

development) or from $50 to $1,170 million (unrestricted development). All costs are given in terms of 1986 dollars.

ES.8 REGULATORY IMPACTS ON MODEL PROJECTS

Thirty-four model projects were considered in the analysis, spanning a wide range in size, productivity, and profitability. Table ES-4 summarizes the economic impacts seen for a typical project for the selected sets of effluent control options. These impacts are based on the most reasonable average oil price projected for the 15-year period, i.e., $21/bbl in 1986 dollars. The Gulf 12 oil and gas project is used in the example.

Under the membrane filter cost assumptions, the corporate cost and production cost per BOE increases by 1 to 4 percent for existing projects and from 1 to 2 percent for new projects. The net present value of the project decreases by 5 to 7 percent for existing projects and from 3 to 4 percent for new projects. For new projects, the internal rate of return declines from 2 to 3 percent under the various regulatory packages. The typical project, however, will recover the cost of the incremental pollution control.

Under the granular filter cost assumptions, the corporate cost per barrel-of-oil equivalent (BOE) and production cost per BOE increase from 15 to 26 percent for existing projects and from 1 to 3 percent for new projects. The net present value of the project decreases from 20 to 24 percent for existing projects and from 5 to 6 percent for new projects. The internal rate of return for new projects decreases by 4 to 5 percent under the various regulatory packages.

For projects larger than the Gulf 12-well platform, impacts are generally less than those seen in Table ES-4, because the costs are spread over a larger amount of production or form a smaller portion of the total investment and operating costs. The inverse is true for projects smaller than the Gulf 12-well platform. Costs must be spread over a smaller amount of production and form a larger portion of total investment and operating costs; hence, impacts are larger.

TABLE ES-4

SUMMARY OF IMPACTS OF COMBINED REGULATORY OPTIONS ON TYPICAL PROJECTS

Effluent Guideline	Effluent	Effluent Control Option	Cost Assumption	Change in Typical Project Financial Summary Statistics*: Corporate Cost per BOE	Production Cost per BOE	Internal Rate of Return	Net Present Value
BAT	Produced Water	Zero Discharge	Granular Filter Costs	19.0%	26.2%	NA	-24.2%
			Membrane Filter Costs	3.6%	4.2%	NA	-7.0%
		Filtration	Granular Filter Costs	15.2%	20.7%	NA	-19.9%
			Membrane Filter Costs	1.6%	1.3%	NA	-4.7%
NSPS	Drilling Fluid and Drill Cuttings Produced Water	4-Mile Barge; 1,1 Other Zero Discharge	Granular Filter Costs	2.0%	3.4%	-4.5%	-6.1%
	Drilling Fluid and Drill Cuttings Produced Water	4-Mile Barge; 1,1 Other Zero Discharge	Membrane Filter Costs	1.2%	2.2%	-3.0%	-4.0%
	Drilling Fluid and Drill Cuttings Produced Water	4-Mile Barge; 1,1 Other Filtration	Granular Filter Costs	1.4%	2.5%	-3.5%	-4.5%
	Drilling Fluid and Drill Cuttings Produced Water	4-Mile Barge; 1,1 Other Filtration	Membrane Filter Costs	0.8%	1.8%	-2.0%	-3.1%
	Drilling Fluid and Drill Cuttings Produced Water	4-Mile Barge; 1,1 Other BPT	NA	0.2%	0.6%	-1.0%	-0.9%

Notes: * Based on a Gulf 12 oil and gas project.
BOE = barrels of oil equivalent.
NA = not applicable.

Source: ERG estimates.

ES.9 REGULATORY IMPACTS ON OIL AND GAS INDUSTRY

Offshore development is financed by a small number of very large major and independent oil companies. Data on publicly held companies are used to define balance sheets for representative major and independent oil companies. These balance sheets are then used to judge the impact of pollution control requirements of these proposed effluent guidelines and standards. Two methods for financing the regulatory costs are considered -- working capital and long-term debt. The incremental costs of additional pollution control are negligible when compared to the financial base of these companies.

Impacts are minimal for a typical major under any set of pollution control options and either set of development assumptions. The financial ratios affected by debt financing change by less than 1 percent under any combination of options and costs. The current ratio declines by no more than 0.4 percent. Financing <u>all</u> BAT and NSPS costs by working capital would decrease that parameter by no more than 4 percent.

The change in financial ratios for a typical independent under the various combinations of regulatory options and price assumptions is greater than that seen for a typical major. Under the most reasonable projected development scenarios, $21/bbl oil price with restricted development, the financial ratios affected by debt-financing increase by no more than 1.6 percent under the options investigated. Under regulatory package B (Zero Discharge for produced water), working capital may decrease by 39 percent and the current ratio may decline by 3 percent. Under regulatory package F (4-Mile Filter; BPT Other), working capital declines by 2 to 4 percent. All other ratios change by no more than 0.2 percent for this regulatory package. For the other packages, current ratio declines by 1.7 percent or less, and working capital decreases by 1 to 22 percent. It must be questioned, however, whether a typical independent would chose to fund all of these expenditures out of working capital or whether some mix of working capital and debt would be used.

ES.10 REGULATORY IMPACTS ON PRODUCTION

The total amount of production[3] from BAT and NSPS structures was calculated. This estimate was compared to the total production under the six sets of regulatory options. Under regulatory package F, the potential loss in production is less than 0.1 percent of total offshore production. Under regulatory package B, production declines by 1.8 percent. The production declines for the other packages range from 0 to 0.7 percent.

ES.11 SECONDARY IMPACTS OF THE REGULATIONS

The impact of the effluent guidelines regulations on Federal revenues, State revenues, and the balance of payments is analyzed. Federal revenues are impacted by the tax effects of effluent guidelines expenditures and by potential reductions in lease/bonus bids. The potential impact of the regulations on Federal revenues is estimated to be between $28 and $1,017 million (1986 dollars) in the year 2000, depending upon the regulatory package. For regulatory package F, the potential loss in Federal revenues is estimated to be $50 million in the year 2000. State revenues might be affected by reductions in lease/bonus bids. The maximum impact of the guidelines on State revenues is $2 to $64 million in the year 2000. For either Texas' and Louisiana's estimated share of the impact, lost revenues are less than 0.5 percent of the State's total 1986 revenues. No significant impacts on the balance of trade or inflation are projected.

ES.12 IMPACT ON SMALL BUSINESSES

The effluent guidelines expenditures will be financed by major and independent oil companies. These are not small businesses by any standard; therefore, no Regulatory Flexibility Analysis was undertaken.

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[3]Production is expressed in terms of BOE (barrels-of-oil equivalent) in order to compare both oil and gas production on a common basis. The conversion factor is based on the heating value of the product. A barrel of oil is 5.8 million BTU and an MMCF of gas is 1,021 million BTU. An MMCF of gas is equivalent to 176.03 BOE.

SECTION ONE

INTRODUCTION AND SUMMARY OF REGULATORY OPTIONS

1.1 INTRODUCTION

This report evaluates the economic impact of proposed effluent limitations guidelines and standards of performance on the offshore oil and gas industry. This industry searches for and produces hydrocarbons located in offshore areas. The industry is included as a subcategory of the oil and gas extraction point-source category under the Clean Water Act (the Act). Two activities of the offshore oil and gas industry generate effluents. First, drilling for oil and gas involves the use and discharge of drilling fluids and drill cuttings. Drilling fluids are liquids used to lubricate the drill bit and carry away cut rock to the surface in a well drilling operation. Drill cuttings are fragments of the host rock removed by the drilling operation. Second, the production of oil and gas results in the generation and discharge of waters associated with the hydrocarbons (i.e., produced waters) in the subsea reservoirs.

The Environmental Protection Agency (the Agency) is required under Sections 301, 304, 306, and 307 of the Act to establish effluent limitations guidelines and standards of performance for industrial dischargers. To further these requirements, the following effluent guidelines and standards are being proposed:

- <u>BCT</u> - Effluent reductions employing the best conventional pollutant control technology as required under Section 304(b)(4).
- <u>BAT</u> - Effluent reductions employing the best available control technology economically achievable as required under Section 304(b)(2).
- <u>NSPS</u> - New source performance standards covering new sources as required under Section 306(b) of the Act.

On August 26, 1985, the Agency proposed BAT and NSPS for drilling fluids, drill cuttings, and produced water waste streams. In the same notice, BCT was proposed to be equal to BPT effluent limitations guidelines. The Agency, however, reserved BCT effluent limitations guidelines for additional conventional pollutant parameters for these waste streams for future rulemakings. On October 21, 1988, the Agency published a Notice of Data Availability and Request for Comments relating to the discharge of drilling fluids and drill cuttings.

Since 1985, the Agency has gathered additional data and other information concerning the treatment and disposal of drilling fluids, drill cuttings, and produced water. In light of this additional information, the Agency has decided to repropose effluent limitations guidelines for the offshore oil and gas industry. This report evaluates the costs and economic impacts of the BAT and NSPS regulatory options for drilling fluids, drill cuttings, and produced waters examined for the reproposal. BCT options are discussed in the Development Document.

1.2 SUMMARY OF REGULATORY OPTIONS

1.2.1 Drilling Fluids and Drill Cuttings

Five options for BAT and NSPS were developed for the control of drilling fluids and drill cuttings. The following requirements are included in some combination in the various options:

- No discharge of drilling fluids or drill cuttings.
- No discharge of diesel oil in detectable amounts or no discharge of drilling fluids and drill cuttings associated with oil-based drilling fluids.
- No discharge of "free oil" as measured by the static sheen test.
- Toxicity limitation as measured by a 96-hour LC_{50} test.
- Limitations on cadmium and mercury.
- Zero discharge of fluids and cuttings based on distance from shore. The zero discharge requirement is presumed to be met by barging the fluids and cuttings to shore for disposal.

Each requirement is discussed more fully below.

<u>No Discharge of Oil-Based Drilling Fluids</u>: This requirement, which is included in all options under consideration, is a continuation of the effective prohibition on the discharge of oil-based fluids that results from the BPT requirement of "no discharge of free oil." The discharge of cuttings

associated with oil-based fluids is also prohibited. Cuttings associated with diesel oil-based fluids are assumed to fail a visual sheen test, a BPT requirement. Cuttings associated with mineral oil-based fluids are assumed to pass a visual sheen test. Under all the BAT/NSPS regulatory approaches, however, all cuttings associated with either diesel oil- or mineral oil-based fluids must be barged. The barging of cuttings associated with mineral oil-based fluids is therefore a BAT/NSPS cost.

No Discharge of Diesel Oil in Detectable Amounts: Diesel oil is a complex mixture of petroleum hydrocarbons. It is known to be highly toxic to marine organisms and to contain priority and toxic nonconventional pollutants. Diesel oil is an "indicator" pollutant for control of the discharge of priority pollutants. Diesel oil has been used in water-based drilling fluids as a lubricity agent and as a "spotting" agent to free stuck pipes. This requirement prohibits the discharge of drilling fluids and drill cuttings to which diesel oil has been added for lubricity or spotting purposes. Such wastes must be transported to shore for proper disposal or reuse. An alternative method to comply with this requirement is the substitution of less toxic mineral oil for diesel oil. This requirement is included in all regulatory options.

No Discharge of "Free Oil" (static sheen test for fluids and cuttings): BPT regulations prohibit the discharge of "free oil" based on a visual sheen test. That is, no sheen, slick, or iridescence may be visible as the drilling fluid is discharged into the receiving water body. A static sheen test is a more sensitive indicator of "free oil" than the visual sheen test. The static sheen test involves mixing the waste to be discharged with seawater in a container, allowing the mixture to stand for a period of time, and then observing whether the waste caused a sheen, iridescence, gloss, or increased reflectance on the surface of the test seawater. The occurrence of any such observed effect would prohibit the discharge of that waste into the receiving seawater. This requirement applies to all options.

Toxicity Limitation: All options limit the toxicity of the discharge of drilling fluids as measured using a 96-hour LC_{50} toxicity test. The toxicity limitation is established at a 30,000 ppm suspended particulate phase (SPP). The purpose of the requirement is to reduce the levels of toxic constituents in drilling fluid discharges, including those contributed by spotting and lubricity agents and other specialty additives.

<u>Limitation on Mercury and Cadmium Content</u>: All options limit the amount of mercury and cadmium in drilling fluids. For some options, the concentration of mercury or cadmium in the discharged drilling fluids must not exceed 1 mg/kg each (dry-weight basis). These options are termed "1,1 All" or "1,1 Other" throughout this report. This requirement is presumed to be met by the use of barite in which mercury and cadmium concentrations do not exceed 1 mg/kg each. For the other options, the not-to-exceed limit is 3 mg/kg mercury and 5 mg/kg cadmium dry-weight basis in the stock barite. These options are referred to as "5,3 All" and "5,3 Other" throughout the report.

<u>Zero Discharge Based on Distance from Shore</u>: Under the "Zero Discharge" option, all fluids and cuttings must be barged to shore for treatment and disposal. Under these circumstances, limitations on mercury, cadmium, toxicity, and diesel oil are rendered moot since the fluids and cuttings will not be discharged. Under "4-Mile Barge" options, all fluids and cuttings from wells drilled within 4 miles of shore must be barged to shore for treatment and disposal. Fluids and cuttings from wells beyond 4 miles of shore must adhere to limitations on mercury and cadmium content, toxicity, and diesel oil.

These requirements have been combined into five options:

- **Zero Discharge** - all fluids and cuttings are barged to shore for treatment and disposal.
- **4-Mile Barge; 1,1 Other** - fluids and cuttings from wells drilled within 4 miles of shore are barged to shore for disposal. Fluids and cuttings from wells beyond 4 miles of shore must meet a 1,1 mg/kg limit on mercury and cadmium content, pass the toxicity test, substitute mineral oil for diesel oil, and pass the static sheen test.
- **4-Mile Barge; 5,3 Other** - fluids and cuttings from wells drilled within 4 miles of shore are barged to shore for disposal. Fluids and cuttings from wells beyond 4 miles of shore must meet a 5,3 mg/kg limit on cadmium and mercury content (respectively), pass the toxicity test, substitute mineral oil for diesel oil, and pass the static sheen test.
- **1,1 All** - all fluids and cuttings must meet a 1,1 mg/kg limit on mercury and cadmium content, pass the toxicity test, substitute mineral oil for diesel oil, and pass the static sheen test.
- **5,3 All** - all fluids and cuttings must meet a 5,3 mg/kg limit on cadmium and mercury content (respectively), pass the toxicity test, substitute mineral oil for diesel oil, and pass the static sheen test.

Due to the dangers and high costs involved in barging drilling wastes in arctic conditions, Alaska has been exempted from barging requirements under the 4-Mile Barge options. Wells drilled in this region, however, must comply with either the 1,1 All or 5,3 All requirements under the 4-Mile Barge; 1,1 Other and the 4-Mile Barge; 5,3 Other options, respectively.

1.2.2 Produced Water

Two methods are considered for the treatment and discharge or zero discharge of produced water:

- Filtration and discharge.
- Injection.

Two sets of costing assumptions are investigated, one reflecting the use of membrane filters and the other reflecting granular filter costs. The reader is referred to the development document for more details.

These options are combined with the 4-mile boundary described in Section 1.2.1 to create the three options for consideration for BAT (existing) and NSPS (future) production facilities:

- **Zero Discharge** - all produced water is injected.
- **All Filter** - all produced water is filtered and discharged at the offshore facility.
- **4-Mile Filter; BPT Other** - produced water from facilities within 4 miles of shore is filtered and discharged at the offshore facility while other facilities must meet BPT requirements.

BPT (Best Practicable Control Technology Currently Available) requirements currently limit the discharge of oil and grease in produced water to a daily maximum of 72 mg/L and a 30-day average of 48 mg/L.

1.2.3 Combinations of Selected Regulatory Options

The Agency selected six "packages" of regulatory options for further analysis. Each package has an option for:

- Drilling fluids and drill cuttings.
- BAT produced water.
- NSPS produced water.

The packages are summarized in Table 1-1.

TABLE 1-1

SUMMARY OF REGULATORY PACKAGES

Regulatory Package	Effluent	Effluent Control Option
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	4-Mile Filter; BPT Other
	Produced Water - NSPS	4-Mile Filter; BPT Other
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	Zero Discharge
	Produced Water - NSPS	Zero Discharge
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	All Filter
	Produced Water - NSPS	All Filter
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	All Filter - Membrane
	Produced Water - NSPS	All Filter - Membrane
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	BPT All
	Produced Water - NSPS	BPT All
F**	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*
	Produced Water - BAT	4-Mile Filter; BPT Other - Membrane
	Produced Water - NSPS	4-Mile Filter; BPT Other - Membrane

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

** Selected Package.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology.

Source: Industrial Technology Division, U.S. Environmental Protection Agency.

SECTION TWO

CHARACTERIZATION OF OFFSHORE OIL AND GAS ACTIVITY

The offshore oil and gas industry leases, explores, and develops areas located off the coasts outside the inner boundary of the territorial seas of the United States. The industry leases (i.e., acquires the right to operate on) offshore areas from Federal or state governments. Once an area is leased, exploration wells are drilled to determine whether hydrocarbons are present. If oil or gas is found in sufficient quantities, development wells and a production platform are put in place. From these facilities oil and gas are produced and conveyed to markets.

Sections 2.1 through 2.4 provide an overview of the activities of the offshore oil and gas industry. Section 2.1 describes the Federal and state leasing programs under which offshore development occurs. Section 2.2 describes the exploration activities undertaken by developers searching for oil and gas in leased areas. Section 2.3 profiles production activity now under way on offshore leases. Section 2.4 describes the activities which support and maintain offshore leasing, exploration, and development. Section 2.5 reviews the industry downturn and recovery during the 1986 to 1988 period.

2.1 OFFSHORE LEASING

Offshore developers lease areas from the Federal government or from state governments. The Federal government has jurisdiction over areas beyond 3 miles from the coast. State government jurisdiction, therefore, is over areas within 3 miles of the coast. The exceptions to this rule are Texas and Florida, which have jurisdiction over areas up to 3 leagues (9 nautical miles, or 10.4 statute miles) from their shores. The exact line of jurisdiction in Alaska is still under negotiation.

Leased tracts are available for both oil and gas development. Either commodity, or both, is produced depending on its presence on the tract and on the economics of transporting the commodity to market.

2.1.1 Federal Leasing

Lease Sales

Federal leasing involves the auction of lease tracts in areas of Federal jurisdiction. Lease tracts are the unit of territory leased. The standard offshore lease tract is 5,760 acres or 9 square miles. In any one lease sale, a large number of tracts might be offered in a specific area. The government will lease only those tracts in which an acceptably high bonus bid (i.e., initial payment by the developer to operate on the lease) is received. The acceptability of bids is determined within the U.S. Department of the Interior (DOI).

Table 2-1 provides a history of all of the Federal offshore lease sales through December 1985. As shown in the table, lease sale activity has accelerated somewhat in recent years. Throughout the 31-year history of the program, nearly 419.5 million acres have been offered and nearly 41 million acres leased. A total of 77,553 lease tracts were offered, 9,009 tracts were bid on, and 8,063 tracts leased during that period. In 1985, 87 million acres were offered and over 3 million acres were leased, and 15,754 tracts were offered and 642 tracts were leased. Most of the leasing that has occurred has been off the coasts of Texas, Louisiana, and California. In more recent years, tracts have also been offered off the Atlantic and Alaskan coasts.

Table 2-2 provides a summary of Federal leasing activity for 1980-86. The number of tracts offered per year ranges from 483 to 27,984. Six percent of the tracts offered during the 6-year period were bid on. Of the tracts bid on, 90 percent of the bids were accepted.

Leasing Revenues

Payments made by lessees are of two types: bonus payments and royalties.[1] Bonus payments are initial amounts paid by developers for the right to operate on a lease. Royalties are per-unit payments made by operators for each unit of oil or gas produced on the lease.

[1]A third category, annual rental payments at $8/hectare (equals $20/acre), is of insufficient magnitude to be considered in the economic analysis.

TABLE 2-1

OUTER CONTINENTAL SHELF (OCS) FEDERAL LEASE SALE STATISTICS

1954-1985

Bid Opening			Sale Offering		Bids Made			
Sale	Date	Area	Tracts	Acres	Number	Tracts	Acres	Total Exposed
1	10/13/54	LA	199	748,819	336	90	394,721	$ 302,924,834
1S	10/13/54	LA	108	523,630	5	5	25,000	1,233,500
2	11/09/54	TX	38	111,789	90	19	67,149	73,801,896
3	07/12/55	TX,LA	210	674,095	384	121	402,567	323,240,052
5	05/26/59	FL	80	458,000	23	23	132,480	1,711,872
6	08/11/59	LA	38	81,813	56	28	62,967	174,411,628
7	02/24/60	TX,LA	385	1,610,254	444	173	813,663	575,175,650
8SA	05/19/60	LA	10	22,085	1	1	2,500	75,250
PH *	12/15/61	SCA	16	80,640	6	6	30,240	N/A
9	03/13/62	LA	401	1,808,276	538	212	981,407	314,218,540
10	03/16/62	TX,LA	410	1,875,984	666	210	977,092	605,357,718
11	10/09/62	LA	19	33,855	26	14	24,858	66,265,290
P-1	05/14/63	CA	129	669,777	70	58	312,975	13,989,953
12	04/28/64	LA	28	34,028	69	23	32,671	93,850,051
P-2	10/01/64	OR,WA	196	1,090,074	222	101	580,853	53,579,753
13S	12/14/65	TX	658	947,520	113	50	72,000	56,324,364
14	03/29/66	LA	18	35,993	64	18	35,993	275,384,739
15	10/18/66	LA	52	227,898	79	32	134,717	185,214,816
P-3	12/15/66	CA	1	1,995	7	1	1,995	89,937,020
16	06/13/67	LA	206	971,489	743	172	812,202	1,627,749,269
17SA	09/05/67	LA	8	16,995	1	1	2,495	30,564
P-4	02/06/68	CA	110	540,609	164	75	383,341	1,293,601,113
18	05/21/68	TX	169	728,551	556	141	666,631	1,620,393,212
19	11/19/68	LA	26	46,824	38	21	40,262	398,430,736
19A	01/14/69	LA	38	96,389	40	26	61,628	71,036,938
20S	05/13/69	LA	120	165,605	43	38	50,880	4,070,549
19B	12/16/69	LA	27	93,764	58	16	60,153	230,460,743
21	07/21/70	LA	34	73,360	59	21	50,889	163,451,158
22	12/15/70	LA	127	593,485	1,043	127	593,485	2,877,429,559
23	11/04/71	LA	18	55,872	33	13	42,222	172,735,981
24	09/12/72	LA	78	366,682	324	74	346,693	1,599,155,464
25	12/19/72	LA	132	604,029	690	119	548,374	6,191,018,227
26	06/19/73	TX,LA	129	697,643	551	104	566,573	6,248,160,989
32	12/20/73	MAFLA	147	817,297	373	89	496,917	3,404,892,968
33	03/28/74	LA	206	930,918	402	114	522,397	6,474,003,574
34	05/29/74	TX	245	1,355,678	352	123	680,355	3,354,292,556
S1	07/30/74	TX,LA	258	1,298,739	57	49	249,704	88,799,354
36	10/16/74	LA	297	1,421,546	387	157	733,927	2,521,756,919
		Subtotal: (1954-74)	5,371	21,912,000	9,113	2,665	11,994,976	$41,548,166,799

Leases Issued			High-Bid Bonuses		High Bids Rejected		Average Bid	First-Year
Sale	Tracts	Acres	Submitted	Accepted	No.	Amount	per Acre	Rentals
1	90	394,721	$ 116,378,476	$ 116,378,476	0	0	$ 294.84	$ 1,184,175
1S	5	25,000	1,233,500	1,233,500	0	0	49.34	50,000
2	19	67,149	23,357,029	23,357,029	0	0	347.84	201,450
3	121	402,567	108,528,726	108,528,726	0	0	269.59	1,207,722
5	23	132,480	1,711,872	1,711,872	0	0	12.92	397,440
6	19	38,820	90,286,693	88,035,120	9	$ 2,251,573	2.267.28	388,200
7	147	704,526	285,180,648	282,641,815	26	2,538,833	401.18	2,113,599
8SA	1	2,500	75,250	75,250	0	0	30.10	7,500
PH	(6)	(30,240)	(122,000)	(122,000)	0	0	4.03	N/A
9	206	956,407	177,745,105	177,260,305	6	484,800	185.34	2,855,433
10	205	956,592	268,724,090	268,333,397	5	390,693	280.51	2,869,638
11	9	16,178	44,399,399	43,887,359	5	512,040	2,712.79	161,780
P-1	57	312,945	12,807,587	12,807,337	1	250	40.93	938,838
12	23	32,671	60,340,626	60,340,626	0	0	1,846.90	326,780
P-2	101	580,853	35,533,701	35,533,701	0	0	61.18	1,742,562
13S	50	72,000	33,740,309	33,740,309	0	0	468.62	216,000
14	17	35,056	89,054,406	88,845,963	1	208,443	2,534.44	350,570
15	24	104,717	101,730,216	99,164,930	8	2,565,286	946.98	523,600
P-3	1	1,995	21,189,000	21,189,000	0	0	10,618.50	9,980
16	158	744,456	511,957,288	510,079,178	14	1,878,110	685.17	2,233,458
17SA	1	2,495	30,564	30,564	0	0	12.25	7,485
P-4	71	363,181	603,204,284	602,719,262	4	485,022	1,659.56	1,089,543
18	110	541,304	602,475,717	593,899,046	31	8,576,671	1,097.16	1,623,915
19	16	29,679	150,482,797	149,868,789	5	614,008	5,049.59	296,820
19A	20	48,504	45,588,052	44,037,339	6	1,550,713	907.90	485,050
20S	4	5,625	3,678,045	715,150	34	2,962,895	127.14	16,875
19B	16	60,153	66,908,196	66,908,196	0	0	1,112.30	601,550
21	19	44,642	98,101,013	97,769,013	2	332,000	2,190.07	446,420
22	119	553,898	851,388,599	847,295,760	8	4,092,839	1,529.70	1,661,694
23	11	37,222	96,491,023	96,304,523	2	186,500	2,587.29	372,230
24	62	290,321	586,297,925	585,827,925	12	470,000	2,017.87	870,996
25	116	535,874	1,673,054,912	1,665,519,631	3	7,535,281	3,108.04	1,607,661
26	100	547,173	1,598,590,620	1,591,397,380	4	7,193,240	2,908.40	1,641,519
32	87	485,397	1,491,617,119	1,491,065,231	2	551,888	3,071.85	1,456,197
33	91	421,218	2,175,095,514	2,092,510,854	23	82,584,660	4,967.76	1,263,675
34	102	565,112	1,502,429,426	1,471,851,831	21	30,577,595	2,604.53	1,695,348
S1	19	100,241	76,617,645	30,236,800	30	46,380,845	301.64	300,729
36 * *	144	675,587	1,445,175,340	1,428,261,330	13	16,914,010	* *	2,026,812
	2,384	10,889,259	$15,051,200,712	$14,829,362,517	275	$221,838,195	N/A	$35,243,244

* Only the offering and bidding data for this phosphate lease sale are totaled here since the awarded leases were subsequently terminated and all moneys were returned to the bidder/lessees. See Table 4 footnote for details.

NOTES: Sulphur lease sales have "S" after the sale numbers, and salt lease sales have "SA." PH indicates a phosphate lease sale; P indicates a Pacific (area) sale; RS indicates a reoffering sale. Two-part sales either have "A" and "B" or "1" and "2" after the sale numbers and were accounted for as separate sales, with the exception of Sale 69. See Table 3 footnotes for an explanation.

* * Sale 36 had a two-part bidding system: 10 tracts (51,515 acres) were offered in a royalty bidding system; 287 tracts (1,370,031 acres) were offered in a high bid-bonus system. Of these, 8 tracts (40,755 acres) were bid and let on the royalty system for an average $25.00 per acre ($1,018,875 in bonuses); another 149 tracts (693,172 acres) were bid on the high-bid system with 136 let (634,832 acres) for an average $2,248.22 per acre ($1,427,242,455 in bonuses).

TABLE 2-1 (Cont.)

Bid Opening			Sale Offering		Bids Made			
Sale	Date	Area	Tracts	Acres	Number	Tracts	Acres	Total Exposed
37	02/04/75	TX	515	2,870,344	281	143	796,367	$ 484,721,874
38	05/28/75	TX,LA	283	1,346,432	191	102	486,327	402,752,355
38A	07/29/75	TX,LA	345	1,772,958	179	80	408,009	317,001,333
35	12/11/75	CA	231	1,257,593	166	70	384,540	901,960,364
41	02/18/76	GOM	132	687,604	81	41	191,718	428,003,629
39	04/13/76	GOA	189	1,008,500	244	81	437,524	1,732,170,868
40	08/17/76	Mid-ATL	154	876,750	410	101	575,012	3,513,411,802
44	11/16/76	TX,LA	61	254,488	117	48	201,825	833,015,950
47	06/23/77	GOM	223	1,074,536	424	152	739,326	2,928,091,214
CI	10/27/77	LCI	135	768,580	240	91	518,080	677,075,681
43	03/28/78	S. ATL	224	1,275,273	99	57	324,511	150,927,700
45	04/25/78	TX,LA	145	709,727	283	101	490,752	1,559,345,260
65	10/31/78	GOM	89	511,709	62	35	201,295	87,592,568
51	12/19/78	TX,LA	128	643,987	288	88	449,691	2,355,263,307
49	02/28/79	Mid-ATL	109	620,557	74	44	250,500	66,005,881
48	06/29/79	CA	148	792,845	112	55	294,018	994,683,701
58	07/31/79	GOM	123	577,517	316	88	424,030	3,333,990,620
58A	11/27/79	GOM	124	588,601	322	96	450,914	4,683,195,907
BF	12/11/79	Beaufort	46	172,320	62	25	88,037	945,445,102
42	12/18/79	N. ATL	116	660,409	189	73	415,602	1,270,789,890
A62	09/30/80	GOM	192	909,575	506	147	706,042	7,119,464,691
55	10/21/80	GOA	210	1,195,569	64	37	210,648	197,417,469
62	11/18/80	GOM	81	458,308	268	74	420,058	3,500,570,271
53	05/28/81	CA	111	603,613	301	81	432,817	4,885,810,689
RS-1	06/30/81	AK	175	996,308	7	5	28,466	5,582,362
A66	07/21/81	GOM	212	1,077,913	419	162	829,900	5,227,548,535
56	08/04/81	S. ATL	285	1,622,557	120	54	307,321	561,050,365
60	09/29/81	LCI	153	858,247	15	13	73,158	4,697,309
66	10/20/81	GOM	209	1,081,364	233	107	532,041	2,402,400,552
59	12/08/81	Mid-ATL	253	1,440,376	240	98	557,932	578,952,000
67	02/09/82	GOM	234	1,219,826	290	137	695,749	2,683,699,843
68	06/11/82	S. CA	140	716,840	66	35	176,253	210,486,278
RS-2	08/05/82	ATL,CA,AK	554	3,142,068	48	40	227,727	14,439,195
71	10/13/82	Diapir	338	1,825,770	252	125	683,026	4,589,972,518
69-1	11/17/82	GOM	144	732,570	151	67	339,999	1,185,091,610
		Subtotal: (1975-82)	6,811	36,351,634	7,120	2,753	14,349,215	$60,832,628,693

NOTE: In Sale 53 (May 1981), Chevron USA and Phillips Petroleum jointly paid the highest per acre bid so far, of $65,014.16 on Tract No. 450 in the Santa Maria Basin. Altogether the tract's 5,131 acres brought in $333,596,200 of the total accepted bonus payments of $2,088,881,824. In the same sale, high bidders afterwards relinquished leasing rights to 12 other tracts, thus forfeiting one-fifth or $41,081,734 of their $205,408,672 in bids. Bids for 9 other tracts were rejected as insufficient. The average bid per acre was $6,516.21 on 320,567 acres. As adjusted, totals for this sale also reflect issuance in 1984 of leases for 5 tracts previously delayed by litigation.

Leases Issued			High-Bid Bonuses		High Bids Rejected		Average Bid	First-Year
Sale	Tracts	Acres	Submitted	Accepted	No.	Amount	per Acre	Rentals
37	113	626,585	$ 300,632,667	$ 274,690,955	30	$ 25,941,712	$ 438.39	$ 1,879,761
38	86	406,942	250,681,156	232,916,050	16	17,765,106	572.36	1,220,856
38A	66	336,301	171,511,620	163,214,006	14	8,297,614	485.32	1,008,906
35	56	310,049	438,190,780	417,312,141	14	20,878,639	1,345.96	930,147
41	34	161,286	183,498,244	175,976,493	7	7,521,751	1,091.09	483,867
39	76	409,058	571,871,587	559,836,587	5	12,035,000	1,368.60	1,226,718
40	93	529,466	1,135,802,179	1,127,936,425	8	7,865,754	2,130.33	1,714,176
44	43	178,127	381,911,757	379,148,962	5	2,762,795	2,128.53	534,396
47	124	605,427	1,214,002,429	1,170,093,432	28	43,908,997	1,932.68	1,816,302
CI	87	495,307	400,319,543	398,471,313	4	1,848,230	804.49	1,603,584
43	43	244,807	109,695,692	100,743,443	14	8,952,249	411.52	792,576
45	90	438,756	767,407,369	733,656,893	11	33,750,476	1,672.13	1,316,283
65	35	201,295	61,176,730	61,176,730	0	0	303.92	603,885
51	81	412,416	884,589,799	871,464,998	7	13,124,801	2,113.07	1,237,263
49	39	222,034	41,720,618	40,001,631	5	1,718,987	180.16	718,848
48	54	288,260	573,956,402	572,825,418	1	1,130,984	1,987.18	867,489
58	81	391,183	1,261,358,089	1,247,489,022	7	13,869,067	3,189.02	1,173,570
58A	90	421,519	1,932,894,290	1,913,337,938	6	19,556,352	4,539.15	1,264,590
BF	24	85,776	491,728,138	488,691,137	1	3,037,001	5,697.27	277,808
42	63	358,671	827,832,854	816,516,546	10	11,316,308	2,276.51	1,161,216
A62	116	551,643	2,805,524,393	2,676,927,673	31	128,596,720	4,852.54	1,654,962
55	35	199,261	117,550,113	109,751,073	2	7,799,040	550.79	645,120
62	67	383,323	1,436,448,959	1,417,961,511	7	18,487,448	3,699.12	1,149,969
53	60	320,567	2,277,856,761	2,088,881,824	21	24,648,000	6,516.21	927,312
RS-1	1	5,694	3,091,738	170,496	4	2,921,242	29.95	18,432
A66	156	799,899	2,666,828,352	2,649,628,752	6	17,199,600	3,312.45	2,399,736
56	47	267,580	363,829,954	342,766,174	7	21,063,780	1,280.99	866,304
60	13	73,158	4,405,899	4,405,899	0	0	60.23	236,856
66	102	508,287	1,280,983,917	1,243,468,752	5	37,515,165	2,446.39	1,524,903
59	50	284,659	424,927,000	321,931,000	47	101,268,000	1,130.93	921,600
67	115	590,265	1,251,793,459	1,193,654,719	22	58,138,740	2,022.29	1,770,795
68	29	147,066	132,252,632	117,875,281	6	14,377,351	668.77	443,913
RS-2	36	204,955	12,310,706	11,149,450	4	1,161,256	54.40	663,552
71	121	662,861	2,067,604,786	2,055,632,336	4	11,972,450	3,101.00	2,146,112
69-1	56	281,213	634,919,980	609,178,223	11	25,741,757	2,166.24	843,657
	2,382	12,403,696	$27,481,110,592	$26,588,883,283	370	$726,172,372	N/A	$38,045,464

TABLE 2-1 (Cont.)

Bid Opening			Sale Offering		Bids Made			
Sale	Date	Area	Tracts	Acres	Number	Tracts	Acres	Total Exposed
69-2	03/08/83	GOM	125	665,478	20	13	68,106	$ 48,755,129
57	03/15/83	Norton	418	2,379,751	98	64	364,364	371,803,984
70	04/12/83	St. Geo	479	2,688,787	150	97	546,609	547,731,283
76	04/26/83	Mid-ATL	4,050	22,664,991	53	40	227,727	86,822,680
72	05/25/83	CGOM	7,050	37,867,762	1,015	656	3,249,135	4,582,847,288
78	07/26/83	S. ATL	3,582	20,156,426	12	11	62,625	14,262,040
74	08/24/83	WGOM	5,848	32,620,248	773	436	2,410,782	2,350,359,669
73	11/30/83	Cen-ÇA	137	768,341	14	8	43,799	24,045,646
79	01/05/84	EGOM	8,868	50,631,513	226	156	897,786	500,261,361
83	04/17/84	Navarin	5,036	28,048,995	425	186	1,058,932	1,148,701,653
81	04/24/84	CGOM	6,502	34,743,780	793	529	2,650,070	2,126,776,904
84	07/18/84	WGOM	5,446	30,038,593	593	402	2,173,704	1,263,576,675
87	08/22/84	Diapir	1,419	7,773,447	432	232	1,233,573	1,365,968,674
80	10/17/84	S. CA	657	3,147,352	30	25	125,100	73,163,686
98	05/22/85	CGOM	4,531	24,006,157	644	444	2,241,598	1,566,926,725
102	08/14/85	WGOM	4,879	27,199,074	265	210	1,156,841	519,116,036
94	12/18/85	EGOM	6,344	35,823,478	114	82	450,259	155,241,798
		Subtotal: (1983-85)	65,371	361,224,173	5,657	3,591	18,961,010	$ 16,746,361,231
		Total: (1954-85)	77,553	419,487,807	21,890	9,009	45,305,201	$119,127,156,723

Leases Issued			High-Bid Bonuses		High Bids Rejected		Average Bid	First-Year
Sale	Tracts	Acres	Submitted	Accepted	No.	Amount	per Acre	Rentals
69-2	11	58,117	$ 39,741,340	$ 37,570,900	2	$ 2,170,440	$ 646.47	$ 174,360
57	59	335,898	325,267,372	317,873,372	5	7,394,000	946.34	1,087,488
70	96	540,917	427,343,830	426,458,830	1	885,000	788.40	1,751,248
76	37	210,648	71,141,240	68,410,240	3	2,731,000	324.77	681,984
72	623	3,089,812	3,469,214,969	3,367,606,134	33	101,608,835	1,089.91	9,269,616
78	11	62,625	13,062,040	13,062,040	0	0	208.58	202,752
74	406	2,246,005	1,549,262,300	1,501,712,517	30	47,549,783	668.62	6,738,015
73	8	43,801	16,022,336	16,022,336	0	0	365.82	141,808
79	156	897,786	310,586,261	310,586,261	0	0	345.95	2,693,358
83	180	1,024,772	631,228,331	624,491,331	6	6,737,000	609.40	2,784,366
81	453	2,278,129	1,446,584,927	1,323,036,649	76	123,548,278	580.76	6,834,537
84	361	1,949,186	945,717,312	844,850,488	41	100,866,824	433.44	5,847,639
87	231	1,230,486	877,131,327	871,964,327	1	5,167,000	708.63	3,910,184
80	23	114,363	66,231,426	62,121,252	2	4,110,174	543.20	347,157
98	409	2,076,907	1,147,434,447	1,079,377,760	35	68,056,687	519.70	6,230,829
102	195	1,075,188	391,137,536	359,175,656	15	31,961,880	334.06	3,225,597
94 *	38	215,948	122,022,098	49,473,298	0	0	229.10	647,844
	3,297	17,450,588	$11,849,129,092	$11,273,793,391	250	$ 502,786,901	N/A	$ 52,568,782
	8,063	40,743,543	$54,381,440,396	$52,692,039,191	895	$1,450,797,467	N/A	$125,857,375

NOTES: In Sale 74 (August 1983), two of the high bidders failed to execute leases on time and had to forfeit their one-fifth bonus deposits.

In Sale 73 (November 1983), litigation delayed the scheduled bid opening until December.

Pending settlement of international boundary disputes with the Soviet Union (Sale 83/April 1984) and Canada (Sale 87/August 1984), issuance of some leases remains on hold, although the data are herein reported. These include 17 tracts on 96,784 acres for $108,174,000 in bids received (Sale 83) and 4 tracts on 22,773 acres for $5,104,000 in bids received (Sale 87). These bids may be rejected by the Federal Government at any time; or after 5 years from the day of the bid opening, they also may be withdrawn by the bidder. If the bids are either rejected or withdrawn, the bonus deposits together with accrued interest moneys will be returned to the bidders.

* In Sale 94 (December 1985), one high bidder did not execute 5 awarded leases on time (of the 38) and forfeited the one-fifth bonus deposit ($12,331,200). Thus, 33 leases from this sale are in effect so far.

Leases have not been issued to high bidders in Sale 94 for another 19 tracts (205,511 acres), pending resolution of the hold imposed under Military Stipulation 5.

Source: U.S. Department of the Interior, Minerals Management Service
Federal Offshore Statistics: 1985, OCS Report , MMS 87-0008,
Table 2

TABLE 2-2

OCS LEASING STATISTICS, 1980-1986

YEAR	NO. OF TRACTS OFFERED	NO. OF TRACTS BID ON	NO. OF TRACTS SOLD	AVERAGE BONUS BID PER TRACT* (millions of $)
1980	483	258	218	19.3
1981	1,398	520	430	15.4
1982	1,410	404	357	11.2
1983	1,689	1,325	1,251	4.6
1984	27,984	1,530	1,404	2.9
1985	15,754	736	642	2.3
1986	10,724	155	142	1.3

*Current dollars.

Source: "Federal Offshore Statistics: 1984," U.S. Department of the Interior, Minerals Management Service, MMS 86-0067; "Federal Offshore Statistics: 1985," U.S. Department of the Interior, Minerals Management Service, MMS 87-0008, from Tables 2 and 3; and "Outer Continental Shelf Statistical Summary, 1986," U.S. Department of the Interior, Minerals Management Service, MMS 86-0122.

Tables 2-1 and 2-2 provide economic data on the Federal offshore lease sales for which summary data have been published to date. The tables show the bonus payments (or "bid prices") that have been received for leased areas. During the period from October 1954 through December 1985, bonus payments totaling over $52 billion were received by the Federal treasury for offshore tracts, with the average tract leasing for $6.5 million (Table 2-1). Average lease bonus payments per tract peaked during 1980-1982 when the average ranged from $11.2 million to $19.3 million per tract. These figures have declined and average bonuses for 1983 through 1986 range from $1.3 million to $4.6 million (Table 2-2). These declines reflect the recent downturn in drilling activity due to depressed oil prices.

The other major category of payments made by lease developers is royalty payments. These payments are set as a proportion of the value[1] of oil and gas produced. Royalty payments are set in most cases at between one-eighth and one-sixth of the value of the produced oil and gas. For example, royalties on a $20 barrel of oil would be $2.50 to $3.33.

Table 2-3 shows the royalties that have been received by the Federal government for offshore oil and gas production. Note that over $27 billion in royalties have been paid through 1986. As the number of operating platforms grows, annual levels of royalty payments continue to grow. In 1984 alone, over $3.8 billion of oil and gas royalty payments were made for OCS leases.

Outer continental shelf (OCS) leasing by the U.S. Department of the Interior provides a considerable amount of revenue to the U.S. Treasury in the forms of bonus and royalty payments. The Bureau of Land Management (BLM) OCS office in New Orleans, which coordinates all Federal lease sales, is third only to the Internal Revenue Service and the Bureau of Alcohol, Tobacco and Firearms in government revenue production. Table 2-4 shows the annual revenue to the U.S. government resulting from offshore oil and gas leases including both bonus and royalty payments. Almost $10 billion was received in 1981 as a result of Federal leasing, although the annual figure has declined with only $3 billion received in 1986.

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[1]Value, as used here, is equivalent to the wellhead selling price of oil or gas. Because oil or gas are frequently not sold at the wellhead, the term "value" is the wellhead value of the oil or gas established by MMS based on information concerning regional wellhead selling prices.

TABLE 2-3

TOTAL ROYALTY REVENUES BY COMMODITY AND YEAR FROM ALL OFFSHORE FEDERAL LEASES, 1953-1986

	ROYALTIES PAID (BILLIONS OF DOLLARS)[a]	
YEAR	OIL	GAS
1953-1980	$5.378	$4.669
1981	1.575	1.712
1982	1.740	2.075
1983	1.640	1.815
1984	1.823	2.091
1985	1.707	1.906
1986	1.015	1.518
Total (1953-1986)	$14.878	$12.362

[a]Does not include royalties for substances other than oil and natural gas; such subsidies amounted to $0.239 billion (cumulative) for the period 1953-1986. Values in current dollars.

Sources: "Mineral Revenues: The 1985 Report on Receipts from Federal and Indian Leases," U.S. Department of the Interior, Minerals Management Service, MMS 86-0067, Table 8, and "Mineral Revenues: The 1986 Report on Receipts from Federal and Indian Leases," U.S. Department of the Interior, Minerals Management Service, Table 8.

TABLE 2-4

TOTAL OCS FEDERAL OFFSHORE LEASING SUMMARY, 1975-1986 FOR ALL REGIONS

YEAR	NUMBER OF SALES	SALE ACTIVITY: ACREAGE OFFERED	SALE ACTIVITY: ACREAGE LEASED	SALE ACTIVITY: TRACTS LEASED	PRODUCTION: CRUDE AND CONDENSATE (MILLION BBL)	PRODUCTION: GAS (TRILLION CU FT)	GOVERNMENT RECEIPTS (BILLIONS OF DOLLARS)*: BONUS	GOVERNMENT RECEIPTS (BILLIONS OF DOLLARS)*: ROYALTY
1975	4	7,247,247	1,679,877	321	330	3.459	1.088	0.595
1976	4	2,827,342	1,277,936	246	317	3.596	2.243	0.680
1977	2	1,843,116	1,100,741	211	304	3.738	1.569	0.890
1978	4	3,140,696	1,297,280	249	292	4.386	1.767	1.139
1979	6	3,412,249	1,767,512	351	286	4.673	5.079	1.512
1980	3	2,563,452	1,134,238	218	277	3.641	4.205	2.132
1981	7	7,679,740	2,265,649	430	290	4.850	6.599	3.287
1982	5	7,637,122	1,886,359	357	321	4.680	3.987	3.815
1983	7	120,054,037	6,587,879	1,251	348	4.041	5.749	3.454
1984	6	154,383,680	7,494,803	1,404	370	4.538	4.037	3.915
1985	3	87,028,709	3,368,043	642	389	4.001	1.488	3.613
1986	2	58,670,103	734,419	142	389	3.949	0.187	2.533

*Current dollars.

Source: "Federal Offshore Statistics: 1984," U.S. Department of the Interior, Minerals Management Service, MMS 86-0067; "Federal Offshore Statistics: 1985," U.S. Department of the Interior, Minerals Management Service, MMS 87-0008, Tables 3, 16, 19, and 20; and "Mineral Revenues: The 1986 Report on Receipts from Federal and Indian Leases," U.S. Department of the Interior, Minerals Management Service, Royalty Management Program.

Other Federal Lease Provisions

Besides the bonus and royalty payments associated with Federal leases, there are a number of other key lease conditions. The duration of leases is usually 5 years. In areas with harsh climates or in very deep waters, the initial term may be set at 10 years. The leases are automatically renewable if production is established.

Other conditions of the leases include various stipulations which may be appended to the lease. Examples of these stipulations are:

Cultural Resources
Biological Resources
Drilling Fluids and Drill Cuttings and Formation Water Disposal
Military Area
NASA Area
Geologic Hazards
Undetonated Explosives and Radioactive Materials

The intent of the cultural resources and biological resources stipulations is to ensure that if an archeological find or an endangered species or habitat is found within a lease area, care will be taken to protect it. The military area and NASA area stipulations are added to the lease if it is felt that drilling activity may interfere with military or NASA operations. Geological hazards analysis may be required under the geological hazards stipulation if the bottom is known to be unstable or unable to support a drilling platform. The disposal of drilling fluids and drill cuttings and formation or produced waters has been restricted (under the geologic hazards stipulation) in some areas to protect the marine environment.[1] A final stipulation may require that any undetonated explosives or radioactive materials be located prior to drilling.

2.1.2 State Leasing Activity

Each state runs its own leasing program and there is no coordination between the states and the Federal Minerals Management Service in the leasing process. Most states do not publish historical data on individual lease

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[1]Such a restriction differs from EPA effluent guidelines in that the former is applied only where a unique or very sensitive ecology is involved.

sales. Information on each of the states presented in the tables below is based mostly on conversations with state land commission personnel. One factor that is common to all state leasing programs is the slowdown in leasing activity since late 1981. This has been attributed to the current oil glut and slump in oil prices. State officials anticipate an increase in leasing activity when the demand for and price of oil increase again.

Table 2-5 summarizes the key financial aspects of the state leasing programs and Table 2-6 summarizes historical and planned leasing activities. Overall approximately 28 percent of the offshore development that has occurred to date has been in state waters.

2.2 OFFSHORE OIL AND GAS EXPLORATION

Prior to the lease sale, companies perform seismic investigations on sites that have potential as hydrocarbon reservoirs. Based on seismic analysis of the subsurface rock structures, the company will make an estimate of the potential quantity of extractable oil and gas. The results of these investigations are considered proprietary information. The expected market value of the extractable oil and gas is the basis for deciding whether to bid on a particular tract, and what the cash value of the bid should be. Seismic investigations cannot fully define an oil formation. (Of those areas that seismic studies identify as candidates for exploratory drilling, only 15 percent of the tracts drilled will prove to contain economic amounts of oil or gas.)

After a company has leased a tract and the necessary permits have been obtained, exploratory drilling can commence. Several exploration wells may be drilled on a tract, depending on the high-potential areas indicated by seismic and structural analysis. Exploration wells are usually drilled from mobile drilling platforms that are operated by contractors for petroleum companies.

Table 2-7 provides historical statistics on the level of exploratory drilling that has occurred in each offshore region up to January 1, 1985. An estimated 7,468 exploratory wells had been drilled as of that time. Of these, 5,206 have been drilled in Federal waters. This is an average of approximately .70 exploratory well per leased Federal tract, i.e., 5,206 wells drilled on 7,418 tracts leased at the end of 1984 (see Table 2-1). Of all wells, oil was found in 376 cases (5.0 percent), gas was found in 641 cases (8.6 percent), and 6,451 (86.4 percent) were dry holes. Historically, 30

TABLE 2-5

SUMMARY OF STATE OFFSHORE LEASE TERMS

STATE	LEASE DURATION	DRILLING REQUIRED	RENT	BONUS	ROYALTY RATE
Alabama[a]	5 yr - renewed if producing	yes	$5/acre/year	Bid item--has ranged from $438/acre to $31,500/acre	16.67% minimum-set by board for each lease sale
Alaska[b]	------------All Conditions Variable------------				
California[c]	20 yr and then for as long as producing	yes	PRESENT- $1/acre	Bid item--has ranged from $100,000 to $250,000,000 for 5000-acre parcel	Sliding royalty depending on production, ranging from 1/6 to 1/2
			FUTURE OPTION 10,000,000/ parcel first 3 yr, then $1/acre	---	FUTURE OPTION Bid item-percent of net profits
Louisiana[d]	5 yr--renewed if producing	yes	Not less than 1/2 of cash bonus	Bid item	Bid item-varies from 20% up
Texas[e]	5 yr--renewed if producing	yes	$10/acre	Bid item - minimum $180/acres	Bid item - minimum 25%

[a]Alabama Department of Conservation, State Lands Division, R. McRory, March 1987.
[b]Alaska Department of Natural Resources, Lease Sale Section, E. Phillips, March 1987.
[c]California State Lands Commission, A. Willard, March 1987.
[d]Louisiana State Mineral Board, M. Hays, March 1987.
[e]Texas General Land Office, S. Sharlot, March 1987.

TABLE 2-6
HISTORICAL AND PLANNED STATE OFFSHORE LEASING ACTIVITIES

State	Currently Leased Acres	Production Activity (No. of Platforms)	Future Planned Lease Sales
Alabama	105,000	2	One sale scheduled for July 1988
Alaska		15	Five sales planned 1988-1992 involving offshore tracts.
California	132,419	15	None currently planned; environmental impact assessments proceding for several potential future sales.
Florida	2,600,000	0	None
Louisiana	249,889	800	Lease sales are held monthly; leasing activity has declined since 1980
Texas	430,000	113	Lease sales held twice per year; leasing activity has declined since the early 1980s.

Sources:

Alaska — Litzen, Kelly. Alaska Dep't of Natural Resources, Division of Oil and Gas. Telephone conversation, 1/88.
Douglas, Russ. Alaska Oil & Gas Conservation Commission. Telephone conversation, 3/88.
Alaska Dep't of Natural Resources, Div. of Oil and Gas. Five Year Oil and Gas Leasing Program. 1/88.

Alabama — McRory, Robert. Alabama Dep't of Conservation, State Land Division. Telephone conversation, 3/88.

California — Willard, Al. California State Lands Commission. Telephone conversation, 3/88.
California Dep't of Conservation, Div. of Oil and Gas. 1987. 72nd Annual Report of the State Oil & Gas Supervisor. Sacramento.

Florida — Hachenberger, Ed. Florida Dep't of Natural Resources, Division of State Lands. Telephone Conversation, 3/88.

Louisiana — Alexander, Sarah. Louisiana Off. of Mineral Resources, Mineral Board, Production Audit Section. Telephone conversation, March 1988.
U.S. Department of Interior, Minerals Management Service, as reported by OOC in a letter to EPA.

Texas — Boone, Peter. Texas General Land Office. Telephone conservation, March 1988.

TABLE 2-7

TOTAL OFFSHORE[a] EXPLORATORY DRILLING IN THE UNITED STATES FEDERAL AND STATE LEASES ALLTIME TO JANUARY 1, 1985

LOCATION	NUMBER OF EXPLORATORY WELLS			
	OIL	GAS	DRY	TOTAL
ALASKA				
State	19	7	54	80
Federal	1	--	19	20
Total	20	7	73	100
CALIFORNIA				
State	20	10	139	169
Federal	24	--	155	179
Total	44	10	294	348
OREGON				
Federal	--	--	8	8
WASHINGTON				
State	--	--	2	2
Federal	--	--	4	4
Total	--	--	6	6
PACIFIC COAST[b]				
Federal	--	--	38	38
PACIFIC OCEAN[c]				
State	39	17	195	251
Federal	25	--	224	249
Total	64	17	419	500
FLORIDA				
State	--	--	15	15
Federal	--	--	9	9
Total	--	--	24	24
LOUISIANA				
State	61	96	920	1,077
Federal	206	253	3,079	3,538
Total	267	349	3,999	4,615
TEXAS				
State	35	182	700	917
Federal	10	91	1,032	1,113
Total	45	273	1,732	2,050

(Cont.)

TABLE 2-7 (Continued)

LOCATION	NUMBER OF EXPLORATORY WELLS			
	OIL	GAS	DRY	TOTAL
N. GULF OF MEXICO[d]				
Federal	--	--	241	241
GULF OF MEXICO				
State	96	278	1,635	2,009
Federal	216	344	4,361	4,921
Total	312	622	5,996	6,930
ALABAMA				
State (Mobile Bay)	--	2	--	2
ATLANTIC OCEAN				
Federal	--	--	36	36
GRAND TOTAL				
State	135	297	1,830	2,262
Federal	241	344	4,621	5,206
Total	376	641	6,451	7,468

[a]Offshore wells are defined as those producing from beyond natural shorelines.

[b]Pacific waters north of Southern California.

[c]Southern California Pacific waters.

[d]In 1972 BLM designated certain areas previously not mapped or leased to this area, including areas to the south of the Texas and Louisiana Federal waters.

Source: Basic Petroleum Data Book, Volume VIII, No. 1, January 1988, Section XI, Table 7.

percent of exploratory drilling occurred in state waters and 70 percent in Federal waters.

2.3 OFFSHORE OIL AND GAS DEVELOPMENT

2.3.1 Development Logistics

Once exploratory drilling has established that oil or gas is present on a leased tract, the designated operating company contracts with a drilling company to complete a number of delineation wells. These holes are used to roughly define the areal extent and volume of reservoirs. (A leased tract is the surface area for which the operating company has drilling rights. A reservoir is that part of a subsurface formation that contains oil or gas.) This information, along with porosity, permeability, specific gravity, and viscosity measurements, is used to characterize the reservoir.

The estimated volume of producible reserves, the ease (cost) of extraction, and the expected crude oil price will determine whether or not the operating company will produce the field. Characteristics of the field (volume, porosity, water saturation, and other data used to calculate hydrocarbon volumes) will determine the number and spacing of production wells required for the most efficient exploitation of the reservoir. Spacing can vary from 15 acres/well (the densest spacing for any currently producing field, found in the Beta field off California) to more than 200 acres/well (a less dense spacing more common in the Gulf of Mexico).

Once the data from reservoir delineation have been fully analyzed and a decision made to begin development, a production platform is put in place. Platforms are custom designed for water depth, bottom stability conditions, expected number of wells, size of drilling rig, and other factors. Additional wells, called development wells, are drilled from this permanent production platform. This platform may handle the production of a number of wells. The optimum number of production wells, the depth of the field below the sea floor, and the water depth over the field will determine the required number and placement of production platforms.

2.3.2 Inventory of Offshore Production Platforms

An inventory of existing production platforms on Federal- and state-leased tracts is presented below. This inventory covers all Federal and state waters and both oil and gas production. The boundaries of the offshore subcategory waters are defined in 40 CFR 435. A platform is offshore if it is located seaward of the inner boundary of the territorial seas. For this analysis, we focus on structures that are in production and are likely to incur BAT costs for produced water and drilling effluent disposal under the various regulatory options.

Platforms in Federal Waters

Table 2-8 presents data on the number of platforms located on Federal OCS leases. Overall, there are an estimated 2,253 platforms and approximately 12,300 producing wells. Note that of the 2,253 platforms in Federal waters, 2,233 are in the Gulf of Mexico. The count of structures in the Federal waters of the Gulf of Mexico is based on March 1988 data from the MMS Platform Inspection System, Complex/Structure data base. The count is restricted to those structures that:

- had not been removed as of March 1988
- had at least one drilled, productive well slot (Structures having no well slots, no drilled wellslots, no information on the number of wellslots, or whose wells were used solely for injection, disposal, or as a water source were excluded from the count.)
- were in production and had information on product types (oil, gas, or both)

More details are given in Appendix H on how the count was obtained.

The inventory of structures off the California coast is estimated from data from the California Division of Oil and Gas and the California Coastal Commission. Onshore wells with offshore completions, and structures within inland bays are not included in this inventory since they fall into a different subcategory. At present, no production platforms are in place in Federal waters off the coast of Alaska or in the Atlantic.

TABLE 2-8

FEDERAL WATERS INVENTORY AS OF MARCH 1988
PRODUCING PLATFORMS

AREA	NUMBER OF PRODUCTION PLATFORMS	NUMBER OF PRODUCING WELLS	COMMENTS
Alaska	0	0	All Federal OCS areas still in exploration phase.
Atlantic	0	0	All Federal OCS areas still in exploration phase.
California	20	380	See Table 2-11.
Gulf of Mexico	2,233	11,892	See text.
TOTAL FEDERAL OCS	2,253	12,273	

Source: ERG estimates.

Platforms in State Waters

It is very difficult to obtain a precise count of offshore platforms in State waters. This is because several States define "offshore" as producing beyond the natural shore line. This definition includes wells and structures that are not in the offshore category, such as wells spudded onshore but completed offshore and structures in inland bays. States such as Louisiana and Texas maintain counts of production wells, but not platforms.

Table 2-9 is a listing of platforms in State waters. Where it has been possible to identify offshore structures, this has been done. The data for Louisiana and Texas is starred because of the uncertainties associated with them; it is not possible to precisely identify producing structures and wells that are in the offshore subcategory. This is an area of research that will be undertaken before final promulgation. Table 2-10 is a listing of the platforms off the California coast.

Summary of Platform Count

A total of 2,260 structures was estimated for the count of existing structures in production in the offshore subcategory. This figure includes all structures in Table 2-8, plus the Pacific offshore structures in Table 2-9. The amount of pollution control equipment for produced water allocated to the 2,233 structures in the Gulf of Mexico has:

- Sufficient annual operating and maintenance costs to handle 154 percent of the 1987 water production from State and Federal Gulf of Mexico operations and
- Sufficient capacity to handle an even larger volume of water.

Details are given in Appendix H.

Discussion of Platform Statistics

Assembling this platform inventory raised a number of issues as to how offshore statistics are kept. The following factors should be carefully considered in using and interpreting the platform and well data:

1. Reporting Date. For any statistic, there is a time delay in reporting. For this inventory, it was necessary to use various counts from

TABLE 2-9

STATE WATERS INVENTORY OF OFFSHORE PLATFORMS AND PRODUCING WELLS

State	Number of Production Platforms	Number of Producing Wells	Comments
Alaska	0	0	15 platforms in Cook Inlet; not in offshore category.
California	7	136	see Table 2-10.
Atlantic States	0	0	Little or no current development or exploration activity
Gulf of Mexico			
Alabama	0	0	Gas fields in Mobile Bay are not in offshore category.
Florida	0	0	No activity ongoing or planned other than a small number of exploratory wells.
Louisiana	800*	1,423*	983 oil wells; 440 natural gas wells
Texas	113*	465*	415 natural gas wells; approximately 50 oil wells

* Uncertain how many are in offshore subcategory, coastal subcategory, or are onshore wells with offshore completions.

Sources:

Alaska	Douglas, Russ. Alaska Oil & Gas Conservation Commission. Telephone Conversation, 3/88
Alabama	McRory, Robert. Alabama Dep't of Conservation, State Land Div. Telephone conversation, 3/88.
California	California Dep't of Conservation, Div. of Oil and Gas. 1987. 72nd Annual Report of the State Oil & Gas Supervisor. Sacramento.
Florida	Hachenberger, Ed. Florida Dep't of Natural Resources, Division of State Lands. Telephone Conversation, 3/88.
Louisiana	Bateman, Marlene. Louisiana Off. of Mineral Resources, Mineral Board, Production Audit Section. Telephone conversation, 3/88. U.S. Department of Interior, Minerals Management Service, as reported by OOC in a letter to EPA, dated 8/13/1984.
Texas	Boone, Peter. Texas General Land Office. Telephone conservation, March 1988.

tab2_10.wk1

TABLE 2-10
PACIFIC OFFSHORE PLATFORMS
1987 DATA

Field	Platform Name	Year Installed	Water Depth (ft)	Number of Producing Wells in Field
FEDERAL				
Beta	Edith	1983	161	
Beta	Ellen	1980	265	
Beta	Eureka	1984	700	61
Carpinteria	Henry	1979	291	
Carpinteria	Hogan	1967	150	
Carpinteria	Houchin	1968	151	65
Dos Cuadras	A	1968	188	
Dos Cuadras	B	1968	188	
Dos Cuadras	C	1977	193	
Dos Cuadras	Hillhouse	1969	190	142
Hueneme	Gina	1980	95	6
Pitas Pt	Habitat	1981	303	14
Pt. Arguello	Harvest	1985	670	Not producing
Pt. Arguello	Hermosa	1985	602	Not producing
Pt. Arguello	Hidalgo	1987	430	Not producing
Pt. Pedernales	Irene	1985	242	11
St. Clara	Gail	1987	739	
St. Clara	Gilda	1981	210	
St. Clara	Grace	1979	318	60
St. Ynez	Hondo	1976	842	21
Total Producing Wells				380
STATE				
Carpinteria	Heidi	1965	128	
Carpinteria	Hope	1964	140	54
Huntington	Emmy	1961	41	30
Huntington	Eva	1964	58	30
Summerland	Hazel	1957	100	
Summerland	Hilda	1960	106	15
S. Elwood	Holly	1966	211	7
Total Producing Wells				136

Notes: Platform Elly has no wells and is not included in this count.
Onshore wells with offshore completions, wells drilled from islands, and wells drilled in inland bays are not included in the count.

Source: 73rd Annual Report of the State Oil & Gas Supervisor: 1987, California Department of Conservation, 1988;
Oil & Gas Activities Affecting California's Coastal Zone, A Summary Report, California Coastal Commisssion, December 1988.

different sources. It was impossible to present the statistics with one consistent reporting date. However, this introduces only a small error into the counts because the number of platforms added between the earliest and latest reporting date is estimated to be less than 1 percent of all platforms.

2. Old Shut-In Platforms. According to the U.S. Geological Survey (USGS, Gulf of Mexico Summary Report 3, August 1982) approximately 5 percent of the MMS file counts for the Gulf of Mexico platforms may be nonproducing platforms. No adjustments to the inventory were made to account for shut-in platforms.

3. Size of Platforms. Many of the platforms represented in the Texas and Louisiana counts are old 1- to 6-well platforms while the California and Alaska platforms are new 24- to 90-well platforms. Therefore, the platforms in place vary a great deal in size and production capability. All production platforms are included in the inventory, while separate statistics, when available, are provided on the number of wells.

4. Platform Categories. The various statistical sources use different procedures in counting offshore structures. Various types of structures such as production structures may in some cases appear grouped in statistics as "platforms." Only actively producing platforms are included in the counts.

5. Well Categories. Well types include producing wells, dry holes, shut-in wells, injection wells, service wells and field drainage wells. In some cases counts may group together several categories. Where possible, only producing wells are included in the well counts.

6. New Technology. New technology, such as subsea manifolds that allow centralized processing of crude from distant subsea wells, will complicate platform and well inventories. Subsea completions involve installation of wellhead equipment on the ocean floor. It is unlikely that these present a significant problem for existing counts, since they currently represent a very small proportion of all production facilities. According to a 1982 tabulation by Ocean Industry (Ocean Industry, July 1982), subsea production systems in United States waters total less than 50. Therefore, no attempt was made to adjust the platform count to include these structures.[1]

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[1]A trend toward subsea completions would change the number of structures but not the number of wells.

7. New Platforms. In some cases (for example Alabama and California) new platforms have been installed with proven wells but no crude is yet being produced. These platforms have been included in the inventory.

2.3.3 Offshore Oil and Gas Production

Tables 2-11 and 2-12 show the quantity and market value of the oil and gas produced from offshore platforms in recent years, and throughout the history of the Federal outer continental shelf leasing program. The percentage of U.S. oil production from offshore wells compared to total domestic oil production has fluctuated over the last decade, while offshore natural gas production has generally increased in relative importance. In 1975, offshore oil production accounted for 16.2 percent of national production. During the late 1970's and early 1980's when oil prices were high, more onshore production took place and the offshore production dropped to 12-13 percent. As low oil prices begin to shut in marginal onshore wells, offshore production is regaining market share. In 1986, offshore production accounted for 14.4 percent of the national total. The percentage of domestic natural gas produced offshore has climbed, from 20.7 percent in 1975 to a peak of 29.3 percent in 1984. Total offshore natural gas production has also fluctuated between 4.2 trillion cubic feet (1975 production) to 5.5 trillion cubic feet (1981 production). In 1986 over 457 million barrels of oil (14.4 percent of U.S. production) and 4.6 billion million cubic feet of gas (27 percent of U.S. production) came from offshore areas. Together the offshore oil and gas had a market value of nearly $15 billion.

2.4 SUPPORT ACTIVITIES

The leasing, exploration, and development of offshore areas is controlled primarily by large oil companies. These companies are described in detail in Section Three below. While these major and independent oil companies (i.e., the operating companies) finance offshore development directly, a number of contracting and service firms support the operators in all phases of offshore activity (i.e., leasing, exploration, and development). Table 2-13 summarizes the major support activities.

Before an oil company bids for a tract, and after being awarded a lease, it must undertake geophysical investigations. Seismic investigations, which

TABLE 2-11

PRODUCTION AND VALUE OF U.S. CRUDE OIL AND CONDENSATE ONSHORE - OFFSHORE

	PRODUCTION (THOUSANDS OF BARRELS)			OFFSHORE AS A % OF TOTAL	DOLLAR VALUE AT WELLHEAD (THOUSANDS OF DOLLARS)*			WELLHEAD PRICE PER BARREL (DOLLARS)	
YEAR	ONSHORE	OFFSHORE	TOTAL		ONSHORE[a]	OFFSHORE[a]	TOTAL		YEAR
1975	2,560,242	496,537	3,056,779	16.2	19,361,086	3,754,973	23,116,059	7.56	1975
1976	2,508,356	467,824	2,976,180	15.7	20,420,899	3,808,641	24,229,540	8.14	1976
1977	2,546,187	439,173	2,985,360	14.7	21,996,649	3,794,073	25,790,722	8.57	1977
1978	2,761,891	416,325	3,178,216	13.1	24,747,514	3,730,310	28,477,824	8.96	1978
1979	2,722,715	398,595	3,121,310	12.8	34,064,477	4,986,855	39,051,332	12.51	1979
1980	2,766,716	376,649	3,146,365	12.1	57,791,998	7,930,018	65,722,016	20.89	1980
1981	2,743,203	385,421	3,128,624	12.3	87,151,743	12,244,641	99,396,384	31.77	1981
1982	2,744,432	412,283	3,156,715	13.1	78,270,757	11,758,641	90,029,512	28.52	1982
1983	2,744,080	426,919	3,170,999	13.5	71,867,673	11,180,818	83,048,491	26.19	1983
1984	2,780,219	469,477	3,249,696	14.4	71,991,425	12,110,707	84,102,132	25.88	1984
1985	2,818,450	456,103	3,274,553	13.9	67,868,276	10,982,960	78,851,236	24.08	1985
1986	2,710,628	457,624	3,168,252	14.4	34,316,550	5,793,520	40,110,070	12.66	1986

*Current dollars.

[a]Total dollar value distributed in proportion to percentages of production onshore and offshore.

Source: Basic Petroleum Data Book, Vol. VII, No. 1, January 1988, Section XI, Table 3a; Section VI, Table 1.

TABLE 2-12

PRODUCTION AND VALUE OF U.S. NATURAL GAS
ONSHORE - OFFSHORE

YEAR	PRODUCTION (MILLIONS OF CUBIC FEET) ONSHORE	OFFSHORE	TOTAL	OFF-SHORE AS A % OF TOTAL	DOLLAR VALUE AT WELLHEAD (THOUSANDS OF DOLLARS)* ONSHORE[a]	OFFSHORE[a]	TOTAL	WELLHEAD PRICE ($/Mcf)	YEAR
1975	15,943,934	4,164,727	20,108,661	20.7	7,092,450	1,852,612	8,945,062	0.45	1975
1976	15,637,042	4,315,396	19,952,438	21.6	9,069,032	2,502,744	11,571,776	0.58	1976
1977	15,528,536	4,496,927	20,025,463	22.5	12,272,078	3,553,876	15,825,954	0.79	1977
1978	14,839,994	5,134,039	19,974,033	25.7	13,430,116	4,616,384	18,076,500	0.91	1978
1979	15,026,356	5,444,904	20,471,260	26.6	17,699,890	6,413,744	24,113,634	1.18	1979
1980	14,996,551	5,382,236	20,378,787	26.4	23,586,880	8,465,302	32,052,182	1.59	1980
1981	14,631,239	5,546,462	20,177,701	27.5	28,969,884	10,981,964	39,951,848	1.98	1981
1982	13,151,448	5,368,227	18,519,675	29.0	32,308,618	13,188,147	45,496,765	2.46	1982
1983	12,170,095	4,486,905	16,657,000	26.9	31,865,966	11,748,403	43,614,369	2.59	1983
1984	12,888,354	5,341,284	18,229,638	29.3	33,896,371	14,047,577	47,943,948	2.66	1984
1985	12,566,758	4,798,242	17,198,000	27.9	31,123,393	12,043,587	43,166,980	2.51	1985
1986	12,202,345	4,588,565[b]	16,790,910	27.3	23,672,549	8,901,816	32,574,365	1.94	1986

*Current dollars.

[a]Total dollar value distributed in proportion to percentages of production onshore and offshore.

[b]Gross natural gas withdrawals offshore, from Natural Gas Annual 1986

Sources: Basic Petroleum Data Book, Vol. VIII, No. 1, January 1988, Section XI, Table 6a; Natural Gas Annual 1986, October 1987, Tables, 2, 3, and 4.

TABLE 2-13

SUPPORT ACTIVITIES

INDUSTRY CATEGORY	SUPPORT ACTIVITY
Geophysical Contractor	Conducts seismic investigations prior to drilling to determine probability and location of hydrocarbons.
Drilling Contractor	Operates rig and provides crew to drill exploration, delineation, and/or development wells.
Well Logging Contractor	Provides and runs logging devices to determine reservoir characteristics.
Well Servicing Contractor	Provides services necessary to drill and maintain a well such as well servicing, workovers, pulling casing and tubing, and acidizing.
Well Cementing Contractor	Provides equipment and crew to cement wells.
Drilling Mud Contractor	Provides drilling fluid formulations used to cool and lubricate drillbit, remove cuttings from the wellbore, and prevent the flow of fluids into the wellbore while drilling.
Chemical Supplier	Provides special chemicals to formulate drilling fluids, cements, acids, and other specialized formulations needed in the industry.
Equipment Supplier	Supplies specialized equipment used in drilling, production, and environmental control.
Marine Construction Firm	Constructs major offshore structures such as production platforms and pipelines.
Transportation Contractor	Provides transportation services to and from rigs.

Source: ERG.

analyze patterns of subsea geologic structures to determine their potential for oil and gas, account for over 90 percent of geophysical investigations. Geophysical contractors usually perform these investigations under contract to the oil company.

After an operating company has analyzed the results of its geophysical investigations, and has decided where to drill an exploration well or wells, a drilling contractor is selected. Ninety-eight percent of all exploratory and development wells are contracted out to independent drilling contractors. Only about 1 percent of all drilling rigs are owned by operating companies. World- wide there are 105 companies that provide offshore drilling services. Of these 105 companies, 86 are located in the United States. The annual level of activity of drilling contractors is shown in Table 2-14.

During well drilling, well completion prior to production, and well workover during production, other specialized contractors (i.e., servicing companies) are often required. These contractors provide a variety of services including well surveying, well logging, and pulling casings and tubes. Contractors are also needed to cement wells, perforate well casings, acidize and chemically treat wells, as well as to clean out, bail out, and swab wells. Other contractors provide transportation services to and from offshore rigs and platforms.

Among the firms which supply specialized services during offshore drilling are the drilling fluid contractors. These firms supply the chemicals used to lubricate and cool the drillbit during the drilling operations. Unique chemical formulations are required for the various phases of well drilling and a specialized industry has evolved to meet this demand. Some drilling fluid contractors are integrated backwards into production of component raw materials. For example, M-I Drilling Fluids and NL Industries are involved in barite mining as well as the supply of oilfield chemicals. Barite is a major component of drilling fluids.

Another group of companies that support the drilling operation are equipment suppliers. These companies supply specialized equipment used in drilling operation such as shale shakers (i.e., machines that separate drilling cuttings from the drilling fluids). Some of the equipment suppliers are also involved in the supply of drilling fluids.

If an economic quantity of oil or gas is discovered during exploratory drilling, a field development plan is formulated and a marine construction

TABLE 2-14

OFFSHORE DRILLING ACTIVITY, 1973-1985*

YEAR	NUMBER OF WELLS DRILLED	FOOTAGE DRILLED*	AVERAGE DEPTH PER WELL (FT.)
1973	888	8,354,069	9,408
1974	830	7,402,256	8,918
1975	1,028	9,783,176	9,517
1976	1,028	9,817,244	9,550
1977	1,217	11,519,851	9,466
1978	1,197	11,756,744	9,821
1979	1,260	12,392,501	9,835
1980	1,272	12,503,275	9,829
1981	1,476	14,422,470	771
1982	1,464	14,537,052	9,930
1983	1,270	12,831,906	10,104
1984	1,421	14,259,153	10,035
1985	1,247	12,815,948	10,277
1986	898	9,407,734	10,476

*Includes exploration, delineation, and development drilling.

Source: American Petroleum Institute, <u>Basic Petroleum Data Book</u>, January 1988, Section III, Table 10; <u>1986 Joint Association Survey on Drilling Costs</u>, November 1987, Table 1.

firm is hired to build a production system. The marine construction industry includes firms which build platforms, build and lay submarine pipelines, build tankers to transport oil from platforms to shore, manufacture other well and platform equipment, and build offshore service and supply vessels.

In summary, the ownership of the leased offshore mineral interests, and thus the oil produced in leased areas, is entirely held by the operating companies. The operating companies are dominated by a small group of major firms, but the entire offshore oil and gas industry is diverse. The large capital investment needed to explore leased tracts and develop offshore reservoirs is primarily provided by major oil companies, which in turn are supported by a large and independent service and manufacturing industry.

2.5 INDUSTRY DOWNTURN AND RECOVERY 1986-1988

The low oil prices of 1986 led to a downturn in the offshore oil and gas industry. The downturn is particularly evident in terms of leasing and exploration activities as well as in revenues. Table 2-15 lists the domestic first purchase prices for crude oil (also called "wellhead prices") from 1980 to November 1987. The nadir was reached in July 1986 when a barrel of oil sold for only $9.25, less than 30 percent of the 1981 price. Although oil prices now appear to be stabilizing around $18 to $20 a barrel, the Gulf of Mexico appears to be the only region that has begun to respond to the improved market conditions (Wall Street Journal, 18 June 1987, 6, and 1 September 1987, 44).

2.5.1 Federal Offshore Leasing

Lease Sales - Past

Two measures of industry activity are the number of tracts that receive bids and the average bonus bid per tract in Federal lease sales. Table 2-16 summarizes OCS leasing activity from 1980 to 1987. The average bonus bid per tract steadily declined during this period. The number and percentage of tracts receiving bids also declined. In 1980, more than half the tracts offered received bids. Beginning in 1983, substantially larger numbers of tracts were offered and, although the number of tracts receiving bids more than tripled from the 1982 figure, only 6.1 percent of the offered tracts

TABLE 2-15

CRUDE OIL PRICES, 1980 TO NOVEMBER 1987

YEAR MONTH	DOMESTIC FIRST PURCHASE PRICES*
1980 Average	21.59
1981 Average	31.77
1982 Average	28.52
1983 Average	26.19
1984 Average	25.88
1985 Average	24.09
1986	
January	23.12
February	17.65
March	12.62
April	10.68
May	10.75
June	10.68
July	9.25
August	9.77
September	11.09
October	11.00
November	11.05
December	11.73
1986 Average	12.51
1987	
January	13.89
February	14.50
March	14.53
April	14.95
May	15.29
June	15.95
July	16.88
August	17.06
September	16.25
October	15.95
November	15.45

*Current dollars.

Source: Petroleum Marketing Monthly, November 1987, U.S. Department of Energy, Energy Information Agency, DOE/EIA-0380(87/11), Feb. 1988, Table 1.

TABLE 2-16

OCS LEASING STATISTICS, 1980- 1987

YEAR	NO. OF TRACTS OFFERED	NO. OF TRACTS BID ON	NO. OF TRACTS SOLD	AVERAGE BONUS BID PER TRACT (millions of $)*
1980	483	258	218	19.3
1981	1,398	520	430	15.4
1982	1,410	404	357	11.2
1983	21,689	1,325	1,251	4.6
1984	27,984	1,530	1,400	2.9
1985	15,754	736	642	2.3
1986	10,724	155	142	1.3
APRIL 1987	5,881	313	293	0.9
AUGUST 1987	5,045	367	--	--

*Current dollars.

Source: "Federal Offshore Statistics: 1985," U.S. Department of the Interior, Minerals Management Service, MMS 87-0008, from Tables 2 and 3; "Outer Continental Shelf Statistical Summary," U.S. Department of the Interior, Minerals Management Service, MMS 86-0122; Pat Bryars, Minerals Management Service, telephone communication, September, 1987.

received bids. In 1986, only 155 tracts received bids -- this is only 1.4 percent of the tracts offered and is the lowest number seen during this period. As fewer tracts are leased, the area likely to be explored will decline. In time, production and reserves also will fall due to a lower number of discoveries.

Two leasing sales have been held in 1987, both in the Gulf of Mexico. More than 300 tracts received bids in each of the April and August sales; that is, each sale had double the number of tracts bid upon than in all of 1986. Part of the increase in activity may be due to the Minerals Management Service decision to reduce minimum bid requirements from $150/acre to $25/acre. More than 77 percent of the high bids in the August sale amounted to less than $150/acre. An industry journal, however, has stated that the revived interest in Gulf leasing is due more to the stabilization of crude oil prices at levels exceeding $18/bbl (Oil and Gas Journal, 17 August 1987, 24-25). With oil prices double what they were in 1986, companies are now generating more capital for new investments.

Lease Sales - Future

The final 5-year Leasing Plan for 1988 to 1992 was announced in April 1987 (see Table 2-17). The plan provides insight on future levels of offshore leasing and exploration activity. The plan projects that annual sales will continue in the Central and Western Gulf of Mexico. As the 1987 sales indicate, interest in this productive and well-studied area is reviving.

Sales in other OCS areas will occur only every three years. Prior to the new plan, lease sales in these areas were held every two years. Of the 37 sales planned for 1988-1992, nearly one-third are frontier sales to be held only if there is sufficient industry interest (Oil and Gas Journal, 4 May 1987, 26). Lack of interest and other factors have led to several sale cancellations in recent years (Federal Offshore Statistics: 1985, Mineral Management Service, MMS 87-0008, Table 1). Six sales scheduled for the Atlantic have been canceled since 1983. The absence of commercially productive discoveries in that region after eight exploratory wells were drilled reduces the incentive to explore further, particularly in a period of low oil prices (Boston Globe, 28 April 1987). Five sales in Alaska have been canceled and one sale enjoined since 1984. The 5-year plan also defers about 70 percent of all the acreage off California. Given the intense resistance to further development off California, the step was taken to end the uncertainty

TABLE 2-17

FIVE-YEAR OCS LEASING PLAN

SALE NO.	AREA	YEAR	MONTH
97	Beaufort Sea	1988	January
113	Central Gulf of Mexico		March
109	Chukchi Sea		May
115	Western Gulf of Mexico		August
107	Navarin Basin		October
116	Eastern Gulf of Mexico		November
91	Northern California	1989	February
96	North Atlantic		February
118	Central Gulf of Mexico		March
122	Western Gulf of Mexico		August
95	Southern California		September
SU1	Supplemental		September
121*	Mid-Atlantic		October
120*	Norton Basin		December
101*	St. George Basin	1990	February
123	Central Gulf of Mexico		March
117	North Aleutian Basin		May
125	Western Gulf of Mexico		August
114*	Gulf Alaska-Cook Inlet		September
SU2	Supplemental		September
108*	South Atlantic		October
119	Central California		November
124	Beaufort Sea	1991	February
131	Central Gulf of Mexico		March
126	Chukchi Sea		May
135	Western Gulf of Mexico		August
130*	Navarin Basin		September
SU3	Supplemental		September
137	Eastern Gulf of Mexico		November
129*	Shumagin	1992	January
134*	North Atlantic		February
128	Northern California		February
139	Central Gulf of Mexico		March
132*	Washington-Oregon		April
133*	Hope Basin		May
138	Southern California		June
140*	Straits of Florida		June

*Frontier sale to be held only if enough industry interest is indicated in the calls for information and nominations.

Source: Oil and Gas Journal, May 4, 1987, 26.

associated with California lease sales (Oil and Gas Journal, 4 May 1987, 26). Leasing activity in the non-Gulf areas, then, will be far less than in the Gulf.

2.5.2 Exploration

The average number of active rigs is one measure of exploration activity (see Table 2-18 and Figure 2-1). In 1986, the industry slumped to less than half its 1985 levels and the decline continued to worsen in the first half of 1987. The West Coast had no more than two mobile rigs active at any time throughout all of 1986 (Offshore Yearbook, 1987 edition, Pennwell Publishing Company, 86-97).

This severe slump led to "stacking" or placing in storage dozens of offshore drilling rigs. This may prove a problem in future Gulf exploration. Table 2-19 summarizes the number of leases in the Gulf of Mexico that will expire in 1988 and 1989. Over 1,000 undrilled leases will expire during this two-year period. OCS leases are issued for an initial 5-year term and are extended for as long as there is production from that lease. If no drilling is done by the lessee during the initial 5-year period, the lessee loses the lease unless an approved "suspension of operations or production" is obtained (Managing Oil and Gas Operations on the Outer Continental Shelf, Minerals Management Service, September 1986). Many companies may chose to drill rather than lose the lease. If this occurs, a logistical problem may develop in reactivating a sufficient number of rigs to complete drilling on all these leases. The Minerals Management Service has issued a warning that a shortage of drilling rigs will not be considered as a valid reason to extend the terms of any offshore lease (Wall Street Journal, 4 August 1987, 6).

An upturn in drilling activity in the Gulf began in the second half of 1987 (see Figure 2-1). During February and March, 1988, the number of rigs under contract ranged from 146 to 154 for a utilization rate between 61 and 66 percent. (Offshore Data Services, weekly newsletters). The number of rigs working, then, has recovered to levels just prior to the 1986 slump. Given the number of undrilled leases that will expire in the next two years, the demand for offshore drilling services looks likely to continue.

TABLE 2-18

ANNUAL AVERAGE NUMBER OF ACTIVE OFFSHORE DRILLING RIGS

YEAR	AVERAGE NUMBER OF RIGS DRILLING
1979	122
1980	138
1981	151
1982	169
1983	139
1984	200
1985	190
1986	94
1987 (Jan-June)	76

Source: Telephone communication between Maureen F. Kaplan, Eastern Research Group, Inc., and T. Cornetius, Electronic Rig Stats, Houston, Texas, 27 July 1987.

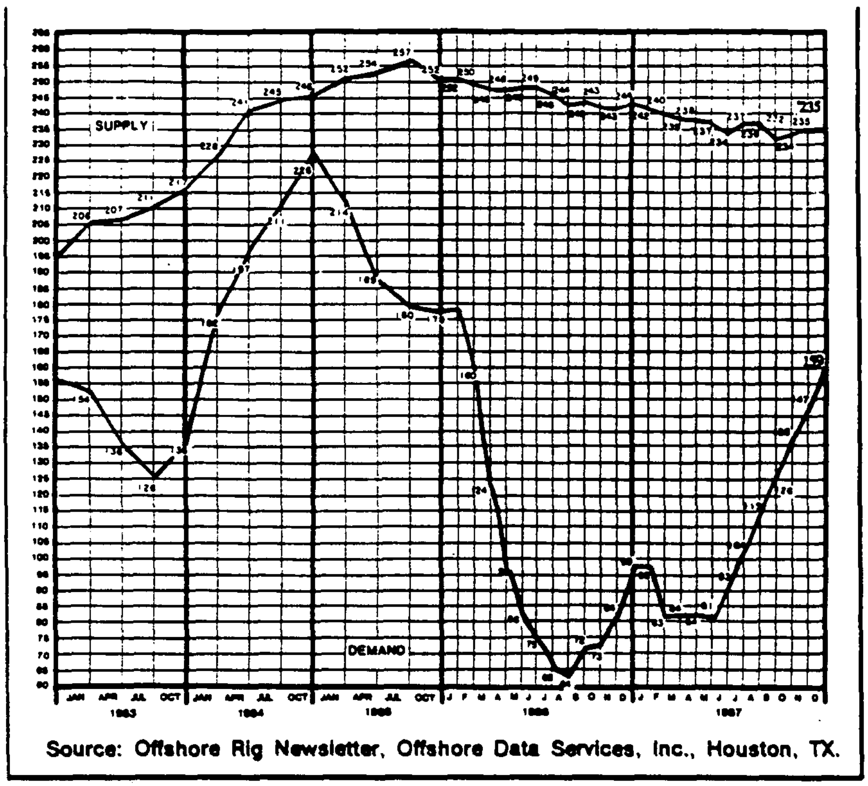

Figure 2-1. Offshore Mobile Rig Utilization Data, Gulf of Mexico, 1983-1988.

Source: Drilling Contractor, December 1987/January 1988.

TABLE 2-19

GULF OF MEXICO LEASES DUE TO EXPIRE 1988-1989

Water Depth (feet)	Year of Exploration			
	1988		1989	
	Drilled	Undrilled	Drilled	Undrilled
up to 150	219	228	61	173
151 to 300	101	81	30	105
301 to 1,300	74	129	42	151
1,301 to 3,000	29	51	24	132
over 3,000	0	0	0	0
TOTAL	423	489	157	561

Source: Drilling Contractor, 1988.

2.5.3 Production

Offshore projects that were begun in 1981-1985, when oil sold for $24-$32/bbl, would only be in the early years of production during 1986 when oil prices fell to less than $10/bbl. It is not surprising, then, that offshore production actually rose by a small amount in 1986 (see Table 2-12). The decline in drilling activity in 1986 will be reflected as a production decline in 1987 and beyond. Onshore oil production in 1986 fell 4 percent as stripper wells were shut-in rather than reworked. Since offshore production remained stable while onshore production declined, offshore production formed a larger proportion (14.4 percent) of total U.S. production than in previous years. Revenues from offshore production, on the other hand, were nearly half of 1985 values due to declining prices.

Offshore petroleum production may continue to increase as a proportion of national production. An article in the Wall Street Journal indicates that oil industry executives believe that only Alaska and the offshore region hold promise of potential giant fields within the U.S. ("Major Oil Firms Intend to Boost Spending in '88," WSJ, November 10, 1987, 4).

SECTION THREE

FINANCIAL PROFILE

The expenditures required to comply with the effluent limitations guidelines and new source performance standards described in Section One will be financed by offshore developers and their investors. Before estimating the impact of the effluent limitation guidelines and standards on the developers, it is useful to evaluate their past and current financial condition. Sections 3.1 through 3.5 provide information on the financial performance of the oil and gas industry.

Section 3.1 identifies and describes the characteristics of companies participating in different phases of offshore development. Section 3.2 reviews the market and financial trends that affect these companies. Section 3.3 presents a ratio analysis of industry segments to identify how key financial ratios have changed over the last 6 years and what this indicates for the future financial condition of those segments. Section 3.4 reviews the principal financial statements of "typical" companies involved in offshore production. Section 3.5 analyzes the industry's future financial prospects. The industry financial ratios (Section 3.3) and representative financial statements (Sections 3.4 and 3.5) are used as the basis for the economic impact analysis presented in Section Seven.

3.1 CORPORATE PARTICIPANTS IN OFFSHORE DEVELOPMENT

3.1.1 Categorization of Participants

Offshore petroleum producers can be divided into two basic categories. The first consists of the major integrated oil companies. These companies are characterized by a high degree of vertical integration, i.e., their activities encompass both "upstream" activities -- oil exploration, development, and production -- and "downstream" activities -- transportation, refining, and marketing. The second category of offshore producers are the large independents. The independents are engaged primarily in exploration, development, and production of oil and gas and are <u>not</u> heavily involved in "downstream" activities. Some independents are strictly producers of oil and gas, while others maintain some service operations, such as contract drilling and pipeline operation. Table 3-1 provides a list of the major domestic integrated and independent oil and gas producing companies.

Producing companies vary in their range of products. In the early 1980's, due to cash surpluses and diminishing oil reserves, many oil companies, and particularly the majors, have diversified into other areas such as mining and development of alternative (nonpetroleum) energy sources. The major oil companies are more oriented toward oil production, while the independents, by contrast, are more oriented toward the production of natural gas.

The major integrated oil companies are generally larger than the independents. Due to the number of mergers and acquisitions in recent years, independents do not appear at all in the top ten companies ranked by domestic oil production, domestic gas production, or net income.[1] As a group, the majors generally produce more oil and gas, earn significantly more revenue and income, have considerably larger assets, and have greater financial resources than the independents.

In addition to the majors and independents, a third group of companies provides a variety of specialized services to the offshore oil and gas developers. These firms construct, own, and operate offshore mobile drilling rigs; fabricate specialized hardware for offshore projects; design, construct, and install offshore platforms; provide geophysical, drilling mud, and well logging services; build and install pipelines to transport oil and gas from platforms to onshore terminals; and own and operate boat and helicopter fleets which provide support services to offshore drilling rigs and platforms. Table 3-2 lists some of the larger participants involved in these support activities.

While all of the companies involved in offshore oil and gas development could be affected by BAT and NSPS regulations, it is the production companies that are directly responsible for having BAT and NSPS systems in operation and they therefore will bear the costs of the regulation. For this reason, the production companies will be the focus of the industry characterization and economic impact assessment. If the costs of BAT or NSPS regulation cause development companies to curtail operations, the companies providing specialized services will experience secondary effects (i.e., a decrease in demand for their services).

[1] Oil and Gas Journal, 8 September 1986, 55-95.

TABLE 3-1

U.S. OIL COMPANIES ENGAGED IN OFFSHORE EXPLORATION, DEVELOPMENT AND PRODUCTION

MAJOR U.S. INTEGRATED OIL COMPANIES	INDEPENDENT U.S. OIL COMPANIES[a]
Amerada Hess	Apache Corp.
American Petrofina	Crystal
Atlantic Richfield	Felmont Oil Co.
Conoco (subsidiary of DuPont)	Inexco Oil Co. (acquired by Louisiana Land and Exploration)
Diamond Shamrock	Louisiana Land and Exploration
Exxon	Mesa Petroleum
Kerr-McGee	Noble Affiliates, Inc.
Marathon Oil (subsidiary of U.S. Steel)	Patrick Petroleum
Mobil Oil	Pogo Producing
Murphy Oil	Sabine Corporation
Occidental Petroleum (acquired Cities Service Co.)	Southland Royalty Company
Phillips Petroleum	Mobil
Shell Oil (subsidiary of Royal Dutch Petroleum)	Wilshire Oil
Standard Oil of California	
Standard Oil of Indiana	
Standard Oil of Ohio	
Sun Company	
Tenneco	
Texaco, Inc.	
Union Oil Company	

Source: "Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 4, 1982; "OGJ 400," Oil and Gas Journal, September 8, 1986.

[a]A sample of the independent companies which are active offshore.

TABLE 3-2

SAMPLE OF COMPANIES PROVIDING SUPPORT SERVICES TO OFFSHORE DEVELOPERS IN 1986

Contract Drilling Services for Offshore Mobile Rigs

Diamond M (subsidiary of Kaneb Services)
Global Marine
Ocean Drilling and Exploration
Penrod Drilling
Pool Offshore (subsidary of ENSERCH Corp.)
Reading and Bates
Rowan Companies
Sedco-Forex (subsidiary of Schlumberger)
Sonat Offshore
Transworld Drilling (subsidiary of Kerr-McGee)
Western Oceanic (Western Co. of North America)
Zapata Corp.

Construction of Offshore Rigs

Bethlehem Steel
CBI Industries
Levingston Shipbuilding
Marathon Manufacturing (subsidiary of Penn Central)

Speciality Hardware Suppliers

Cameron Iron Works
Canocean Resources (subsidiary of Husky Oil)
The Hydril Company
Hughes Tool Co.
NL Industries
VETCO Inc. (subsidiary of Combustion Engineering)

Design, Construction, and Installation of Offshore Platforms

Brown and Root (a division of Halliburton)
CBI Industries
McDermott Inc.
Raymond International

(Cont.)

TABLE 3-2 (CONT.)

Drilling Mud Contractors

Baker International
Dresser
Halliburton
Hughes Tool
Unichem

Well Coring Services

Core Laboratories Inc.
Dowd Co.

Well Logging Services

Gearhart Industries Inc.
Schlumberger

Offshore Pipeline Installation

Brown and Root (a division of Halliburton)
McDermott Inc.

Service Vessel Suppliers

Jackson Marine (subsidiary of Halliburton)
Newpark Resources
Offshore Logistics
Tidewater Marine, Inc.
Zapata Corp.

Contract Diving Services

Oceaneering International

Source: "Oil-Gas Drilling and Services," Basic Analysis, Standard and Poor's Industry Surveys, March 20, 1986; "Offshore 1986: Worldwide Offshore Contractors and Equipment Directory," Pennwell Directories, April, 1986.

3.1.2 Industrial Concentration in Offshore Activities

Company concentration ratios were calculated to determine the degree to which the major integrated companies dominate offshore activities. Table 3-3 presents concentration percentages for offshore domestic operations. The data show that (a) there is a greater degree of concentration for petroleum production offshore than for offshore gas production; (b) the industry concentration ratios for both offshore oil and gas have decreased since 1973 for the 8 and 16 largest company segments; (c) concentration of offshore exploration and development expenditures have tended to vary over the same period; and (d) until 1980, there was a greater concentration in offshore production of oil and gas for the 8 and 16 largest companies than for the country as a whole. These trends indicate that more companies have entered into the oil business since 1973 and particularly into offshore development starting in 1980.

There are four principal areas of offshore oil activity in the United States: Alaska, California, the Gulf of Mexico, and the Atlantic Ocean. The majors dominate operations in all four areas, although much less so in the Gulf. This pattern occurs because the average water depth off the coasts of Alaska and California and in the Atlantic is greater, the areas are less defined geologically, and the operating climates are generally harsher. As a result, development risks are high and few independents have the resources to put at stake in these areas. In contrast, much of the area off the Gulf Coast, especially the state waters, is shallow and has been well explored.

A review of offshore leases announced by the MMS indicates that over 90 percent of all Federal offshore tracts in Alaska and California, 100 percent of the lease tracts in the Atlantic, 85 percent of state lease tracts off the coast of Alaska, and approximately 90 percent of the state tracts off the California coast have been leased by the majors. In contrast, only 75 percent of the Federal leases off the less risky Gulf coasts of Louisiana and Texas are owned by the majors.

TABLE 3-3

OIL INDUSTRY CONCENTRATION RATIOS: OFFSHORE ACTIVITIES AND U.S. ACTIVITIES

	8 LARGEST* COMPANIES					16 LARGEST* COMPANIES					50 LARGEST* COMPANIES					200 LARGEST* COMPANIES				
	1973	1976	1978	1980	1981	1973	1976	1978	1980	1981	1973	1976	1978	1980	1981	1973	1976	1978	1980	1981
__Sales Volume__																				
Crude Petroleum & Condensate																				
Offshore (%)	68.9	57.4	52.1	48.4	46.8	86.0	83.3	72.6	69.0	68.5	96.3	96.3	94.6	93.7	94.5	99.2	99.4	98.8	99.2	98.9
Total Domestic (%	53.5	50.9	47.6	53.5	53.2	72.8	70.7	70.6	72.2	71.8	83.7	82.1	84.3	85.1	84.3	89.9	89.8	90.1	91.2	90.9
Natural Gas																				
Offshore (%)	50.9	48.0	52.9	42.0	41.5	72.6	76.2	73.8	69.3	66.9	93.9	89.6	92.2	90.1	90.2	99.0	99.2	98.9	98.9	99.1
Total Domestic (%)	48.9	44.5	44.8	36.9	36.3	65.5	63.6	60.5	58.5	56.3	81.8	79.2	78.6	79.4	77.9	90.2	89.2	89.5	91.8	90.7
__Lease Revenues__																				
Crude Petroleum & Condensate																				
Offshore ()	68.9	54.2	55.2	46.8	49.4	85.4	77.7	73.2	66.8	71.2	96.3	92.2	93.9	93.7	95.0	99.3	98.9	98.4	99.4	99.6
Total Domestic (%)	54.4	47.1	47.1	50.5	51.9	73.2	64.6	66.2	69.3	71.4	84.2	78.4	78.5	83.4	84.6	90.5	87.8	88.7	90.6	91.5
Natural Gas																				
Offshore (%)	49.7	46.1	46.8	34.5	35.8	71.8	72.1	67.1	62.0	61.8	93.8	88.3	90.5	88.3	88.6	99.1	98.7	98.3	99.0	99.1
Total Domestic (%)	47.9	44.0	41.8	34.9	32.8	64.5	60.4	56.0	53.5	50.8	81.4	77.0	75.6	77.4	74.6	90.4	87.8	88.3	91.8	89.8
__Expenditures (Capitalized and Expensed)__																				
Exploration																				
Offshore (%)	46.3	54.7	45.1	41.4	48.7	66.0	70.7	63.3	66.7	72.0	91.7	89.2	83.7	89.2	90.1	93.9	96.3	97.0	99.4	99.4
Total Domestic (%)	40.1	39.3	34.3	37.0	35.6	56.2	52.9	46.6	56.4	51.5	78.1	71.1	65.9	75.6	70.2	88.4	83.9	84.1	90.5	87.3
Development																				
Offshore (%)	46.9	49.6	43.2	33.6	44.8	62.7	70.1	59.8	60.9	62.4	91.3	88.3	85.8	87.1	89.5	97.1	97.1	97.2	99.3	98.7
Total Domestic (%)	40.8	41.0	36.8	30.3	33.7	54.8	54.5	52.9	59.4	48.3	73.1	77.4	73.9	76.4	66.1	85.0	88.7	88.3	90.3	82.0

Source: Annual surveys of Oil and Gas, Bureau of the Census. The data describe the percentage of industry totals represented by each designated group of the largest firms. These surveys did not continue past 1982. The API __Survey on Oil and Gas Expenditures__ does not contain information categorized by both onshore/offshore operations and company size.

*Companies are ranked by total lease revenues.

3.2 MARKET AND FINANCIAL TRENDS

3.2.1 Market Environment 1975-1986

The environment in which oil companies operate and upon which they base their future plans has changed radically over the last several years. Throughout the 1970's, the world price of oil climbed steadily, beginning with the Arab oil embargo of 1973-1974 and culminating with a large rise in prices in 1979 and 1980. The prevailing industry view in the late 1970's was that oil was relatively price inelastic, i.e., continually rising oil prices would result in little decline in demand and thus generate incrementally higher oil revenues. The industry therefore invested heavily during the 1970's, committing record amounts of capital for exploration and development.

Demand stayed strong throughout most of the 1970's despite rising prices. Demand turned down in 1979, however, and dropped sharply over the next 4 years. Demand rebounded slightly in 1984 and remained level in 1985. Domestic demand for oil fell 19 percent between 1978 and 1981 (Table 3-4), while the average oil wellhead price rose 120 percent in real terms over the same period. Prices peaked in constant dollars in 1981 at an increase of 172 percent over 1978 prices. In 1982, as demand continued to fall, prices also began to slip. The pace of the decline has increased in 1985 and 1986. In 1986, prices fell to levels as low as $12 per barrel before rebounding to approximately $19 at year end. As shown in Table 3-5, demand for natural gas fluctuated during the mid-1970's to the mid-1980's, although the overall trend showed a reduction in demand. During this period, natural gas prices have generally increased, with large jumps in the 1979-1982 period.

There were a number of reasons for the decline in oil prices that began in 1982; a global recession, new supplies brought on-stream in response to higher price expectations, user conservation, and fuel switching all served to slacken demand. The net effect was that the average wellhead price fell 15 percent in real terms from 1981 to 1982. During this time the OPEC oil cartel implemented a variety of supply control strategies to keep the price from falling further. A price war in 1986, engineered by Saudi Arabia in a sharp change in strategy, has driven prices lower still. The falling demand and falling prices quickly affected the industry's spending plans, and had a significant impact on the financial performance and cash flow projections of oil and gas companies. These effects are discussed in more detail below.

TABLE 3-4

TOTAL U.S. PETROLEUM DEMAND, U.S. AVERAGE CRUDE OIL WELLHEAD PRICE, 1975-1986

YEAR	DOMESTIC CONSUMPTION (MILLIONS BARRELS/DAY)	AVERAGE WELLHEAD PRICE	
		CURRENT DOLLARS[b]	CONSTANT DOLLARS[a,b]
1975	16.32	7.67	12.63
1976	17.46	8.19	12.82
1977	18.43	8.57	12.68
1978	18.85	9.00	12.39
1979	18.52	12.64	16.02
1980	17.06	21.59	25.03
1981	16.06	31.77	33.66
1982	15.30	28.52	28.52
1983	15.23	26.19	27.19
1984	15.73	25.88	27.98
1985	15.73	24.09	26.91
1986	16.28	12.51	14.27

Source: Petroleum Marketing Annual 1986, U.S. Department of Energy, Energy Information Administration, DOE/EIA-0487(86)/1; Basic Petroleum Data Book, Vol. VIII, No. 1, January 1988, Section VII, Table 2; Economic Report of the President 1988, Table B3.

[a]Constant 1982 prices calculated using GNP implicit price deflators, 1982 = 100.

[b]U.S. wellhead prices in the 1970's reflect domestic price controls.

TABLE 3-5

TOTAL U.S. NATURAL GAS DEMAND,
U.S. AVERAGE NATURAL GAS WELLHEAD PRICE, 1975-1986

YEAR	DOMESTIC CONSUMPTION (TRILLION CUBIC FEET)	AVERAGE WELLHEAD PRICE	
		CURRENT DOLLARS	CONSTANT DOLLARS[a]
1975	20.4	0.45	0.74
1976	20.8	0.58	0.91
1977	19.52	0.79	1.17
1978	19.63	0.91	1.25
1979	20.24	1.18	1.50
1980	19.88	1.59	1.84
1981	19.40	1.98	2.10
1982	18.00	2.46	2.46
1983	16.83	2.59	2.69
1984	17.95	2.66	2.88
1985	17.28	2.51	2.80
1986	16.22	1.94	2.21

Source: Basic Petroleum Data Book, Vol. VIII, No. 1, January 1988, Section XIII, Table 5; Natural Gas Annual 1985, U.S. Department of Energy Information Administration, DOE/EIA-0131(85), Tables 6 and 26; Economic Report of the President, 1986, Table B3; Natural Gas Annual 1986, Table 1.

[a]Constant 1982 prices calculated using GNP implicit price deflators, 1982 = 100.

3.2.2 Trends in Capital and Exploration Expenditures

Capital and exploration expenditures in the oil and gas industry have quintupled over the last decade (in nominal dollars). Adjusted for inflation, the real level of expenditures has more than doubled.

Table 3-6 shows capital and exploration expenditures by the domestic oil and gas industry for the period 1974-1984. Changes in spending patterns evident in Table 3-6 are closely correlated with oil price movements (see Table 3-4). Capital and exploration spending rose when prices rose sharply between 1979 and 1981. Capital and exploration expenditures in real terms peaked in 1982. The rate of spending fell thereafter as decreased demand and lower prices forced oil companies to cut back on investment programs. In 1986, exploration and development activities fell still further due to the precipitous price decline.

Data on offshore wells drilled, offshore success rates, and offshore drilling costs are shown in Table 3-7. From 1975 to 1986 the average cost per well and per foot increased by a factor of three. Drilling costs tend to correlate with oil price movements with a one-year lag. Drilling costs per foot peaked in 1982 (oil prices in 1981) at a factor of 3.5 from 1975 cost. Drilling costs in 1986 declined measurably from 1985 costs, reflecting the continuing rapid decline in oil prices.

3.2.3 Trends in Offshore Production Reserves

The percentage of U.S. oil production from offshore wells compared to total domestic oil production has generally declined over the last decade, while offshore natural gas production has increased in relative importance. Table 3-8 presents data on the relative importance of offshore oil and gas to total domestic production in terms of revenue. In the ten years ending in 1984, total offshore revenues (in current dollars) grew by a factor of 4.6, to $26.1 billion. These revenues represent approximately one-sixth of total domestic revenues from oil and gas production over that period. The 1984 dollar value of offshore gas production was approximately 29 percent of the value of total gas production, up from 21 percent in 1975. Offshore oil production in 1985 constituted approximately 14 percent of the value of total domestic oil production, down from 16 percent in 1975.

TABLE 3-6

TRENDS IN CAPITAL AND EXPLORATION EXPENDITURES
(UNITED STATES, 1974-1984)

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Total Capital and Exploration Expenditures ($ billion)	17.755	18.920	23.460	24.045	26.450	34.800	46.750	68.700	68.050	49.850	49.925
Increase Over Previous Year (%)	--	6.6	24.0	2.5	10.0	31.6	34.3	47.0	-0.9	-26.7	0.2
Implicit Price Deflator for GNP (1982=100)	54.0	59.3	63.1	67.3	72.2	78.6	85.7	94.0	100.0	103.8	108.1
Total Capital Exploration Expenditures in Constant 1982 Dollars ($ billion)	9.588	11.220	14.803	16.182	19.097	27.353	40.065	64.578	68.050	51.744	53.969

Source: "1984 Capital Investments of the World Petroleum Industry," Chase Manhattan Bank, September 1985; Economic Report of the President, Council of Economic Advisors, February 1986, Table B-3.

TABLE 3-7

OFFSHORE WELLS DRILLED AND DRILLING COSTS 1975-1985*

	# OF OIL WELLS DRILLED	# OF GAS WELLS DRILLED	# OF DRY HOLES	DRY HOLES AS % OF TOTAL	TOTAL WELLS DRILLED	AVG. DEPTH PER WELL (FT.)	AVG. COST PER WELL ($000)	AVG. COST PER FT. ($)
1975	283	271	474	46%	1,028	9,517	1,142	119.99
1976	275	273	480	47%	1,028	9,550	1,435	150.26
1977	288	393	536	44%	1,217	9,466	1,689	178.43
1978	298	419	480	40%	1,197	9,821	2,153	219.22
1979	349	453	458	36%	1,260	9,835	2,545	258.77
1980	317	444	511	40%	1,272	9,829	3,024	307.66
1981	415	515	546	37%	1,476	9,771	3,761	384.87
1982	486	442	536	37%	1,464	9,930	4,203	423.31
1983	459	293	518	41%	1,270	10,104	3,906	386.59
1984	486	372	563	40%	1,421	10,035	3,536	352.33
1985	369	307	571	46%	1,247	10,277	4,073	396.33
1986	333	207	358	40%	898	10,476	4,005	382.28

*Current dollars.

Source: Basic Petroleum Data Book, Vol. VII, No. 1, January 1988, Section III, Table 10; 1985 Joint Association Survey on Drilling Costs, American Petroleum Institute, 1986, Table 3.

TABLE 3-8

DOLLAR VALUE OF ANNUAL OIL AND GAS PRODUCTION 1975-1986
(IN BILLIONS OF CURRENT DOLLARS)

	OFFSHORE PRODUCTION			ONSHORE PRODUCTION			
YEAR	NATURAL GAS	OIL AND CONDENSATE	TOTAL	NATURAL GAS	OIL AND CONDENSATE	TOTAL	OFFSHORE PRODUCTION REVENUES AS A % OF TOTAL
1975	1.9	3.8	5.7	7.1	19.4	26.5	17.7
1976	2.5	3.8	6.3	9.1	20.4	29.5	17.5
1977	3.6	3.8	7.4	12.2	22.0	34.2	17.6
1978	4.6	3.7	8.3	13.4	24.7	38.1	17.9
1979	6.4	5.0	11.4	17.7	34.0	51.7	18.1
1980	8.5	7.9	16.4	23.6	57.8	81.4	16.8
1981	11.0	12.2	23.2	29.0	87.2	116.2	16.6
1982	13.2	11.8	25.0	32.3	78.3	110.6	17.3
1983	11.7	11.2	22.9	31.9	71.9	103.8	18.1
1984	14.0	12.1	26.1	33.9	72.0	105.9	19.8
1985	11.5	11.0	22.5	31.6	67.9	99.5	18.4
1986	8.0	5.8	13.8	24.6	34.3	58.9	19.0

Source: Basic Petroleum Data Book, Vol. VIII, No. 1, January 1988, Section I, Tables 3 and 6; Natural Gas Annual 1986, U.S. Department of Energy, Energy Information Administration, DOE/EIA-131(86), October 1987, Tables 1, 3, and 4.

3.2.4 Financial Trends

During the 1970's to mid-1980's, the oil industry experienced dramatic market changes which affected company revenues and net income.

Table 3-9 presents the data on the oil industry's working capital and capital expenditure levels for the period 1973-1986 from a study of the performance of 25 large domestic and international oil companies (Energy Economics Division, Chase Manhattan Bank, 1981, 1982, 1983, 1985, and 1986 editions). Most of the firms included are major domestic integrated companies; two are large domestic independent companies; also included are several refiners and several foreign companies. Table 3-9 shows aggregate financial measures for the sample companies.

The year-to-year revenue and net income changes for this group of companies is positively correlated with crude oil price increases and worldwide economic cycles. The companies experienced large increases in revenues and net income following the runup in prices resulting from the 1973 Arab oil embargo. In 1975, as the United States and other Western economies were in a recession, net income declined by almost 30 percent, and rates of return fell dramatically. In the following three years, annual increases in net income ranged between 4 and 14 percent, and rates of return improved slightly.

In 1979, another international crisis, the Iranian revolution, precipitated a considerable rise in oil prices. Net income for the group of 25 companies more than doubled in 1979, and rose another 11.7 percent in 1980. Returns on equity and assets peaked in 1979 and 1980 for the 1973-1985 period.

During the 1973-1986 period, internal funds from operations were typically in excess of required capital and exploration expenditures. The exceptions were 1975 and 1981 when net income fell. Net income also fell in 1984 through 1986, but the companies had already begun to reduce capital and exploration expenditures in light of falling oil prices. This excess of funds from operations over expenditures minimizes the need for companies to enter the capital markets to fund their capital programs. Internal cash flow supplied approximately 73 percent of funds used in 1980 by the petroleum industry (Ocean Industry, October 1981). The pattern of financial performance that emerges from a review of financial data from 1973 through 1985 closely tracks

TABLE 3-9

FINANCIAL TRENDS FOR 25 MAJOR PETROLEUM COMPANIES[a,c]
(1973-1985)

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984[b]	1985[b]	1986[b]
Total Revenues ($ billion)	134	245	245	276	317	347	463	603	646	557	514	530	556	397
Net Income ($ billion)	11.7	16.4	11.5	13.1	14.4	15.0	31.5	35.2	29.4	21.3	22.7	20.1	20.0	15.2
% Increase in Net Income	-	40.2	-29.9	13.9	9.9	4.2	110.0	11.7	-16.5	-27.6	6.6	-11.5	-0.5	-24.0
Total Funds from Operations ($ billion)	21.2	28.8	23.6	26.8	30.0	34.3	57.5	66.8	65.4	60.9	60.3	57.2	70.2	54.1
Capital and Exploration Expenditures ($ billion)	14.6	22.9	25.0	26.8	28.0	29.9	43.8	55.6	66.4	71.2	54.9	44.3	49.8	35.0
Capital and Exploration Expenditures as % of Funds From Operations	69	80	106	100	93	87	76	83	102	117	91	77	71	65
Return on Equity (%)	15.5	19.2	12.8	13.8	13.8	13.2	24.0	22.4	16.8	12.2	12.6	11.6	11.8	8.9
Return on Assets (%)	8.6	10.0	6.1	6.6	6.4	6.1	11.0	10.2	7.6	5.6	5.9	5.1	4.8	3.5

[a]Companies include Amerada Hess, Ashland Oil, ARCO (Atlantic Richfield Company), British Petroleum, Champlin Petroleum, Cities Service, Compagnie Francaise des Petroles, Conoco, Exxon, Getty, Gulf, Louisiana Land and Exploration, Marathon Oil, Mobil Oil, Murphy Oil, Petrofina, Phillips Petroleum, Royal Dutch Shell, Standard Oil of California (Chevron), Standard Oil of Indiana (Amoco), Sun Company, Superior Oil, Texaco, Tosco, and Union Oil Company (Unocal).

[b]Revised definitions for "Statements of Income" entries means that 1984, 1985, and 1986 values are not strictly comparable with historical estimates.

[c]Current dollars.

Source: Chase Manhattan Bank, 1985.

the oil price path. A large increase in the price of oil results in large and rapid increases in profitability and funds from operations. Once the rate of price increase moderates, industry profitability returns to more "normal" levels.

To assess the U.S. industry's financial performance for the 1980-1985 period, data are presented for a group of 26 large domestic oil companies (23 are major integrated companies) in Table 3-10. The data in Table 3-10 are based on a study of a slightly different group of 26 companies prepared by the Oil and Gas Journal. Of the 26 companies in the latter sample, 19 were included in the Chase study, and therefore the two groups are readily comparable. The financial data in these tables are calculated by aggregating the appropriate financial measures for each of the companies in the sample and are, therefore, generally representative of major domestic and international oil firms.

Falling demand and prices have affected the major domestic oil companies negatively in this recent period (Oil and Gas Journal, May 25, 1987). Table 3-10 shows the effect of these changes on principal financial variables. Net income fell by $18.4 billion from 1980 through 1986, a decline of 63 percent. Gross revenues also decreased 27 percent.

Capital and exploration expenditures for this group of firms closely track those reported in the Chase study. These expenditures peaked in 1981-82, declined by approximately 25 percent through 1985, and then dropped steeply in 1986 as oil prices plunged.

The profitability measures for the period 1980-86 in Table 3-10 illustrate dramatically the impact of declining oil prices over this period: return on equity fell from 21.0 percent to 7.4 percent, while return on assets fell from 9.3 percent to 2.9 percent.

3.2.5 Increases in Industry Debt

The expansion of capital and exploration expenditures over the period 1979- 1981 was financed primarily through internally generated funds and through an increase in the level of industry debt. Anticipation of an increase in the value of in-ground reserves through rising prices, and an increase in the expected volume of reserves through greater expenditures on exploration, together provided the financial rationale for acquiring this

TABLE 3-10

FINANCIAL STATISTICS FOR 26 LARGE U.S. OIL COMPANIES 1980-1986
(In Billions of Current Dollars)

	1980	1981	1982	1983	1984	1985	1986	PER-CENT CHANGE (1980-1986)
Gross Operating Revenues	493.0	546.4	507.5	500.0	463.8	464.6	358.3	-27.3
Net Income	29.3	28.2	21.9	22.3	20.1	15.8	10.9	-62.8
Funds from Operations	54.9	56.0	52.8	53.1	52.9	56.4	41.2	-25.0
Capital and Exploration Expenditures	52.1	66.9	60.5	48.6	46.6	50.9	33.6	-35.5
Return on Equity (%)	21.0	17.9	12.9	12.3	12.4	10.1	7.4	-64.8
Return on Assets (%)	9.3	7.9	5.9	5.8	5.1	3.8	2.9	-68.8

Companies included in the survey are Amerada Hess*, American Petrofina, ARCO (Atlantic Richfield)*, Ashland Oil*, Cities Service*, Diamond Shamrock, Exxon*, Getty*, Gulf*, Kerr-McGee, Louisiana Land and Exploration*, Marathon*, Mobil*, Murphy*, Occidental, Pennzoil, Phillips*, Shell*, Standard Oil of California (Chevron)*, Standard Oil of Indiana (Amoco)*, Standard Oil of Ohio, Sun*, Superior*, Tenneco, Texaco*, and Union*.

*Companies included in the Chase study.

Source: Oil and Gas Journal, 31 May 1982, 21 March 1983, 11 June 1984, 20 May 1985, 26 May 1986, and May 25, 1987.

additional debt. Independents as a whole increased their use of debt financing at a faster rate than the majors. As prices fell, almost all companies suffered a decline in profits, and those companies that had taken on large amounts of debt also faced increases in interest obligations. In addition, as the value of proven reserves against which much of the debt was secured fell with the decline in prices, pressure mounted for some companies to pay back a portion of their loans. Lenders wanted them to bring the value of their borrowing back into line with the recalculated collateral value of the reserves. This need to provide additional collateral or reduce outstanding debt had a direct and immediate negative impact on the companies' cash position.

A good index measuring a company's debt financing burden is the debt-to-total-capital ratio. As the ratio rises, a company has less flexibility to make further capital expenditures. Table 3-11 presents the debt-to-total-capital ratios for a sample of major integrated companies and independent companies during the 1981-1985 period. The ratios shown were calculated by averaging the ratios of all companies in the sample. The ratios are thus a straightforward company-based average, unaffected by the relative size of companies in the sample. The table shows that major integrated companies experienced an upward trend in their debt-to-capital ratio from 1981 to 1985. For the sample of independent companies, the ratio fluctuated through the 1981-1985 period, with a relatively large seven-percentage-point jump in 1982, a year after capital and exploration expenditures reached their peak. As shown in Table 3-11, the debt-to-capital ratio is significantly higher for the sample of independent companies than for the sample of integrated companies for each year in the 1981-1985 period.

3.3 FINANCIAL CONDITION OF INDUSTRY SEGMENTS

The reduction in demand for oil and natural gas at a time when petroleum companies were expanding their long-term investments had an adverse impact on the companies' financial positions and spending patterns. Profits for the majors generally declined from 1981 to 1985, and spending plans were reduced. The majors retain substantial resources and as a group, have borrowed more conservatively than the independents. The market changes have had a serious impact on certain highly leveraged independents. A review of key financial ratios of the majors and independents highlights these recent trends.

TABLE 3-11

DEBT/CAPITAL RATIOS (%) FOR MAJOR INTEGRATED AND INDEPENDENT COMPANIES

YEAR	SAMPLE OF MAJOR INTEGRATED OIL COMPANIES[a]	SAMPLE OF INDEPENDENT OIL COMPANIES[b]
1981	22.7	34.8
1982	23.9	42.1
1983	23.8	37.3
1984	28.2	39.9
1985	33.1	39.6

[a]Sample consists of Amerada Hess, American Petrofina, ARCO, Diamond Shamrock, Exxon, Getty Oil, Gulf Oil, Kerr-McGee, Mobil Oil, Murphy Oil, Occidental Petroleum, Phillips Petroleum, Shell Oil, Standard Oil of California (Chevron), Standard Oil of Indiana (Amoco), Standard Oil of Ohio, Sun Company, Texaco, Union Oil Company.

[b]Sample consists of Apache Corporation, Cabot Corporation, Conquest Exploration, Damson Oil, Hamilton Oil Corp., Helmerich & Payne, Howell Corporation, Lear Petroleum Corp., LA Land & Exploration, Mitchell Energy & Development, Noble Affiliates, Inc., Pauley Petroleum, Plains Resources, Inc., Pogo Producing, Sabine Corporation, Triton Energy Corporation, Wainco Oil Corporation.

Source: "Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 4, 1982 and November 27, 1986.

3.3.1 Ratios Used to Analyze Industry Segments

The following sections apply ratio analysis methodology to the two basic industry segments under study: major integrated companies and independents. The financial ratios used to analyze the different segments are Return on Equity, Return on Assets, Current Ratio, and Debt/Capital Ratio (already presented in summary form in 3.2, above). The ratios are all calculated using book values. These ratios are important because they are used both by the investment community to evaluate the health and value of the companies and by company executives to formulate exploration, capital expenditure, and production strategies. The expected change in these financial ratios that would occur under each alternative regulatory approach is estimated in Section Seven of this report. Thus, the ratios presented here provide the basis for part of the economic impact assessment which follows.

Return on Equity and Return on Assets are key profitability indicators, measuring the relative earnings performance of a firm. They indicate the overall worth and profitability of the business. Financial lenders, investors, and analysts look for these indices to fall within an acceptable range. Return on Equity is defined as net income divided by shareholders' equity and measures how effective the company's operations are in creating value for the equity holders. Return on Assets is defined as net income divided by the value of assets and measures company efficiency in using assets to make profits. Firms have a certain degree of discretion (within acceptable accounting guidelines) in both stating the value of their assets and in timing and recognizing net income. For this reason, year-to-year comparisons for an individual firm may be misleading. However, the level of these indicators provides a good guide to the earnings performance of a firm if viewed over a number of years.

Current and Debt/Capital Ratios provide measures of a firm's financial health and flexibility. The Current Ratio, which is defined as current assets divided by current liabilities, is used as a measure of a firm's liquidity. It indicates the availability of liquid assets to meet current liabilities. A relatively low ratio (under 1.0) or a falling ratio are danger signals, indicating that a firm may be unable to meet its short-term cash obligations and possibly go into default. If a firm is forced to fall back on non-current assets to meet its current obligations, it may be forced to liquidate these assets at a loss.

The Debt/Capital Ratio[1] measures a company's level of debt or leverage. While some debt is always beneficial for a company's shareholders, too much debt can impose severe constraints on a company's ability to operate and its periodic cash flows. The higher the level of debt, the larger are the regular interest payments the company has to make. These obligations, though tax deductible, reduce net income and use up cash, thus leaving less for reinvestment or for shareholder payments as dividends. In addition, companies with high levels of debt may be unable to acquire additional short-term financing for operations because of constraints placed upon them by existing lenders, or they may only be able to acquire new debt at a very high cost. In general, the higher the level of debt, the greater the possibility that a company may default on its interest payments in the event of an unexpected or severe downturn in revenues.

3.3.2 Ratio Analysis of Major Integrated Companies

Discussion of Financial Ratios

The four financial ratios are presented for 14 domestic integrated companies and five of the international integrated companies who are major U.S. operators, as reported by the Standard and Poor Industrial Surveys. The ratio values for the sample of 19 major integrated companies calculated for 1977 through 1985 or 1986 is presented in Tables 3-12 through 3-18. Also shown are the average value of the ratios for the firms in the sample. The seven tables cover the Return on Equity, Return on Assets, Current and Debt/Capital Ratios. (Table 3-18 provides detailed data on Debt/Capital that were presented in summary form in Table 3-11.) These tables reflect the overall financial performance of the companies covered, not solely their petroleum operations.

The first table (Table 3-12) covering Return on Equity for the ERG sample shows that the average reached a peak in 1980 (23.7 percent) and then declined. The decline in profitability from 1980 is clear. In 1985, 12 of

[1]The Debt/Capital Ratio is defined for this study as the book value of long-term debt as a percent of the book value of invested capital (sum of current liabilities and stockholder equity). This S&P industry survey defines debt/capital ratio as long-term debt as a percentage of total invested capital (sum of stockholder's equity, long-term debt, capital lease obligations, deffered income taxes, investment credits and minority interest). The values on Tables 3-19 and 3-23 are therefore not directly comparable to those on Tables 3-26, 3-22, and 3-32. Values within a given table are calculated on a consistent basis.

TABLE 3-12

RETURN ON EQUITY (%)
MAJOR INTEGRATED OIL C OMPANIES: 19 COMPANY GROUP
(1977-1985)

		RETURN ON EQUITY									
COMPANY	YEAR	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Amerada Hess		25.5	14.0	35.1	26.0	8.9	6.7	8.1	6.7	NM	NM
American Petrofina		10.2	8.2	20.7	22.3	14.2	9.2	9.6	7.2	NM	NM
Atlantic Richfield		17.9	16.8	21.2	25.2	21.3	18.3	15.0	10.9	4.3	11.7
Diamond Shamrock		22.0	15.6	16.4	17.4	16.8	10.8	NM	8.2	NM	NM
Exxon		12.8	14.0	20.2	23.7	20.6	14.7	17.2	19.0	16.8	16.7
Getty Oil (Texaco)		12.9	11.6	19.0	23.1	19.2	14.2	--	--	--	--
Gulf Oil (Chevron)		10.5	10.5	16.1	14.3	12.9	9.4	--	--	--	--
Kerr-McGee		12.4	11.3	13.9	14.3	14.8	13.1	7.0	3.7	7.9	NM
Mobil Oil		12.6	13.1	20.7	23.8	17.5	9.6	10.5	9.2	7.5	9.2
Murphy Oil		11.9	10.7	21.0	24.9	22.2	18.7	14.0	11.8	7.9	NM
Occidental Petroleum		18.3	0.5	52.9	41.4	26.7	2.6	4.2	11.9	8.3	4.2
Phillips Petroleum		17.8	21.1	22.6	23.4	16.9	11.4	12.1	12.7	14.1	11.4

(Cont'd)

TABLE 3-12 (CONT.)

COMPANY YEAR	RETURN ON EQUITY 1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Shell Oil (Royal Dutch Petroleum)	14.7	14.1	17.0	20.4	19.6	10.6	14.9	16.8	12.2	6.2
Standard Oil of California (Chevron)	13.9	13.9	20.4	23.6	20.0	10.6	11.6	10.6	10.2	4.6
Standard Oil of Indiana (Amoco)	15.7	15.5	19.2	21.8	19.1	16.6	15.7	17.5	16.2	6.6
Standard Oil of Ohio	10.1	21.8	45.9	47.3	37.0	28.5	19.7	18.1	3.8	NM
Sun Company	14.8	13.7	20.7	18.1	23.8	10.7	8.6	10.2	9.9	7.3
Texaco	10.1	9.0	17.5	19.4	17.9	9.2	8.5	1.8	9.1	5.3
Unocal	14.6	15.2	18.0	20.1	20.8	18.1	12.6	12.9	8.9	10.5
Unweighted Company Average[a]	14.7	13.9	23.1	23.7	19.5	13.1	11.1	11.1	8.1	NC

NM - Not meaningful, negative net income for that year.

NC - Not calculated. The large number of firms reporting a net loss for 1986 make this average meaningless.

Source: "Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 4, 1982, and November 17, 1986; 1986 data from Oil and Gas Journal, May 25, 1987. May not be strictly comparable to 1977-1985 data.

[a]Simple average of the ratios for the sample.

TABLE 3-13

RETURN ON EQUITY (%)
COMPARISON OF AVERAGE YIELDS
FOR THREE SAMPLES OF MAJOR INTEGRATED OIL COMPANIES
(1977-1986)

	RETURN ON EQUITY										
GROUP	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	10-YEAR AVERAGE
Chase Manhattan Group[a]	13.8	13.2	24.0	22.4	16.8	12.2	12.6	11.6[d]	11.3[d]	8.9	14.7
S&P's Domestic Integrated Oil[b]	14.5	14.3	18.5	20.3	19.8	15.2	13.4	13.9	10.5	4.7	14.5
ERG 19-Company Group[c]	14.7	13.9	23.1	23.7	19.5	13.1	11.1	11.1	8.1	NC	NC

Source: As noted below.

[a]"Financial Analysis of a Group of Petroleum Companies," Energy Economics Division, Chase Manhattan Bank, 1981, 1983, 1985, and 1986 Editions. See Table 3-9 for company list.

[b]Analyst Handbook, Standard & Poor's, Official Series, 1982, 1986, and 1987 Editions.

[c]Table 3-12.

[d]Revised definitions for "Statement of Income" entries means that 1984 and 1985 values are not strictly comparable with historical estimates.

NC - Not calculated.

TABLE 3-14

RETURN ON ASSETS (%)
MAJOR INTEGRATED OIL COMPANIES: 19-COMPANY ERG GROUP
(1977-1985)

	RETURN ON ASSETS									
COMPANY YEAR:	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Amerada Hess	6.0	4.2	11.3	9.6	3.5	2.7	3.3	2.7	NM	NM
American Petrofina	4.6	3.5	8.0	9.2	6.4	4.7	4.3	2.9	NM	NM
Atlantic Richfield	6.8	6.7	8.9	10.7	9.1	8.0	6.9	5.0	1.6	2.8
Diamond Shamrock	9.4	6.7	7.0	7.5	7.5	4.8	NM	4.2	NM	NM
Exxon	6.5	6.9	9.5	10.7	9.4	6.7	7.9	8.8	7.4	7.7
Getty Oil (Texaco)	8.0	7.4	11.2	12.2	9.6	7.2	--	--	--	--
Gulf Oil (Chevron)	5.4	5.4	8.2	7.8	6.5	4.6	--	--	--	--
Kerr-McGee	6.9	6.1	7.3	7.1	6.8	5.8	3.1	1.7	3.7	NM
Mobil Oil	5.1	5.2	8.0	9.3	7.2	4.0	4.2	3.3	2.5	3.6
Murphy Oil	3.7	3.2	6.1	7.2	6.4	5.5	4.6	4.3	3.0	NM

(Cont.)

TABLE 3-14 (CONT.)

COMPANY YEAR:	RETURN ON ASSETS 1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Occidental Petroleum	5.0	0.2	10.9	11.1	9.0	1.3	3.5	4.7	3.8	1.0
Phillips Petroleum	9.5	11.1	11.5	11.7	8.3	5.5	5.7	5.4	3.8	1.8
Shell Oil (Royal Dutch Petroleum)	8.3	8.4	9.1	8.8	9.0	7.7	5.9	7.0	5.4	3.4
Standard Oil of California (Chevron)	7.1	7.0	10.2	11.9	10.4	5.8	6.7	5.1	4.1	2.1
Standard Oil of Indiana (Amoco)	8.4	8.0	9.6	10.4	8.9	7.8	7.5	8.5	7.7	3.2
Standard Oil of Ohio	2.3	5.0	13.4	17.0	14.0	11.8	9.3	8.8	1.7	NM
Sun Company	6.6	6.8	10.2	7.8	9.5	4.5	3.7	4.3	4.1	3.3
Texaco	5.0	4.4	8.1	9.1	8.7	4.7	4.5	0.9	3.3	2.1
Unocal	7.0	7.3	8.7	10.1	11.0	10.0	7.1	7.2	3.1	1.7
Unweighted Company Average*	6.4	6.0	9.3	10.0	8.5	6.0	5.2	5.0	3.2	NC

(Cont.)

TABLE 3-14 (CONT.)

NM = not meaningful.

NC = Not calculated. The large number of firms reporting a net loss for 1986 render this average meaningless.

Source: "Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 4, 1982 and November 27, 1986; 1986 data from Oil and Gas Journal, May 25, 1987. May not be strictly comparable to 1977-1985 data.

[a]Simple average of the ratios for the sample.

TABLE 3-15

RETURN ON ASSETS (%)
COMPARISON OF AVERAGE YIELD FOR 4 SAMPLES OF MAJOR COMPANIES
(1977-1986)

	RETURN ON ASSETS										
GROUP	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	10-YEAR AVERAGE
ERG 19-Company Group[c]	6.4	6.0	9.3	10.0	8.5	6.0	5.2	5.0	3.2	NC	NC
Chase Manhattan Group[a]	6.4	6.1	11.0	10.2	7.6	5.6	5.9	5.1[d]	4.7[d]	3.5	6.6
S&P's Domestic Integrated Oil[b]	7.2	7.1	8.6	9.3	8.9	6.9	6.2	6.2	3.4	1.5	6.5
S&P's 400 Industrials[b]	6.5	6.6	7.2	6.5	6.2	4.6	5.1	5.8	4.4	4.0	5.7

Source: As noted below.

[a]"A Financial Analysis of a Group of Petroleum Companies," Energy Economics Division, Chase Manhattan Bank. Includes large domestic and international petroleum companies. See Table 5-10.

[b]Analyst Handbook, Standard & Poor's, Official Series, 1982 and 1986 Editions.

[c]Table 3-14.

[d]Revised definitions for "Statements of Income" entries means that 1984 and 1985 values are not strictly comparable to historical estimates.

NC = Not calculated.

TABLE 3-16

CURRENT RATIO
MAJOR INTEGRATED OIL COMPANIES: 19-COMPANY ERG GROUP
(1977-1985)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Amerada Hess	1.4	1.3	1.3	1.4	1.3	1.4	1.5	1.4	1.3
American Petrofina	1.4	1.6	1.5	1.5	1.4	1.4	1.2	1.2	1.1
Atlantic Richfield	1.6	1.6	1.6	1.2	1.2	1.2	1.3	0.9	0.6
Diamond Shamrock	2.0	2.0	1.9	2.2	2.0	1.7	1.4	1.2	1.1
Exxon	1.4	1.4	1.3	1.4	1.3	1.2	1.2	1.1	0.9
Getty Oil (Texaco)	1.6	1.5	1.2	0.9	0.9	1.0	--	--	--
Gulf Oil (Chevron)	1.2	1.2	1.3	1.3	1.1	1.1	--	--	--
Kerr-McGee	1.8	1.5	1.7	1.4	1.7	1.5	1.3	1.3	1.2
Mobil Oil	1.2	1.1	1.1	1.1	1.1	1.0	1.1	1.0	1.0
Murphy Oil	1.1	1.1	1.1	1.2	1.1	1.1	1.2	1.2	1.2
Occidental Petroleum	1.4	1.0	1.1	1.1	1.1	1.1	1.0	1.4	1.2
Phillips Petroleum	1.3	1.4	1.3	1.2	0.9	1.1	1.0	0.9	1.0
Shell Oil (Royal Dutch Petroleum)	1.6	1.4	1.0	1.0	1.0	1.0	1.6	1.4	1.4
Standard Oil of California (Chevron)	1.3	1.3	1.4	1.5	1.4	1.3	1.4	1.0	1.1
Standard Oil of Indiana (Amoco)	1.5	1.5	1.3	1.1	1.0	1.1	1.2	1.1	0.9
Standard Oil of Ohio	1.6	1.4	2.0	1.2	0.7	0.8	1.0	0.8	1.1
Sun Company	1.4	1.2	1.3	0.9	1.1	1.1	1.2	1.0	1.2
Texaco	1.4	1.4	1.5	1.7	1.7	1.5	1.5	1.2	1.0
Union Oil Company	1.7	1.7	1.7	1.3	1.1	1.2	1.3	1.2	1.4
Unweighted Company Average[a]	1.5	1.4	1.4	1.3	1.2	1.2	1.3	1.1	1.1

Source: "Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 4, 1982 and November 27, 1986.

[a]Simple average calculated from the ratios for all companies in the sample.

TABLE 3-17

CURRENT RATIO
COMPARISON OF AVERAGE YIELDS FOR
4 SAMPLES OF MAJOR INTEGRATED OIL COMPANIES
(1977-1985)

	CURRENT RATIO										
GROUP	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	10-YEAR AVERAGE
ERG 19-Company Group[a]	1.5	1.4	1.4	1.3	1.2	1.2	1.3	1.1	1.1	NA	1.3
Chase Manhattan Group[b]	1.4	1.3	1.4	1.4	1.3	1.2	1.3	1.2[d]	1.1[d]	1.3	1.3
S&P's Domestic Integrated Oil[c]	1.5	1.5	1.3	1.1	1.0	1.1	1.1	1.0	1.0	1.2	1.2
S&P's 400 Industrials[c]	1.8	1.7	1.6	1.6	1.5	1.5	1.5	1.5	NA	NA	1.6

NA - not available

Source: As noted below.

[a]Table 5-17.

[b]"A Financial Analysis of a Group of Petroleum Companies," Energy Economics Division, Chase Manhattan Bank, 1981, 1983 and 1985 editions.

[c]Analyst Handbook, Standard & Poor's, Official Series, 1982, 1985, 1986, and 1987 Editions.

[d]Revised definitions for "Statements of Income" entries means that 1984 and 1985 values are not strictly comparable to historical estimates.

TABLE 3-18

DEBT/CAPITAL RATIO (%)
MAJOR INTEGRATED OIL COMPANIES IN 19-COMPANY ERG GROUP
(1977-1985)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Amerada Hess	36.7	36.0	30.0	29.5	35.2	38.9	40.3	40.1	40.6
American Petrofina	26.4	45.8	40.4	33.5	28.1	26.0	31.4	39.1	40.8
Atlantic Richfield	34.2	34.6	29.4	27.1	28.9	28.7	26.2	26.9	43.9
Diamond Shamrock	38.1	38.4	38.1	36.0	34.0	34.3	37.0	28.1	40.7
Exxon	14.4	13.3	13.3	12.5	12.0	10.6	10.5	11.6	10.4
Getty Oil (Texaco)	5.8	4.7	4.0	10.8	9.8	16.6	--	--	--
Gulf Oil (Chevron)	13.5	14.1	13.0	10.7	13.0	14.6	--	--	--
Kerr-McGee	20.9	16.6	20.4	24.1	33.1	29.7	27.1	23.5	23.4
Mobil Oil	25.2	25.6	21.3	19.0	17.3	21.1	24.4	40.9	35.8
Murphy Oil	35.5	40.5	32.3	19.1	21.1	16.9	15.1	14.3	13.7
Occidental Petroleum	26.8	39.4	39.0	25.6	20.1	43.5	34.0	43.3	47.6
Phillips Petroleum	21.0	16.3	13.6	12.4	15.0	22.7	23.3	26.0	64.3
Shell Oil (Royal Dutch Petroleum)	20.6	18.4	30.6	33.0	31.3	27.8	19.1	17.3	14.6
Standard Oil of California (Chevron)	16.2	19.7	17.2	13.0	12.4	11.3	10.6	43.4	28.9
Standard Oil of Indiana (Amoco)	25.2	23.5	21.1	18.8	21.4	22.0	20.1	17.3	16.9
Standard Oil of Ohio	71.9	65.4	50.3	39.8	36.1	33.8	29.2	26.4	25.4
Sun Company	18.9	19.4	16.8	34.5	28.6	24.7	24.8	25.3	20.7
Texaco	19.1	24.8	21.8	18.0	15.1	12.8	14.1	41.0	31.6
Union Oil Company	26.8	28.6	26.0	21.9	18.3	18.6	17.6	15.3	64.1
Unweighted Company Average[a]	26.2	27.6	25.2	23.1	22.7	23.9	23.8	28.2	33.1

Source: "Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 4, 1982 and November 27, 1986.

[a]Simple average calculated from the ratios for all companies in the sample.

the 19 companies reported returns below 10 percent, two reported returns between 0 and 5 percent, and three recorded a net loss for the year. In 1986, 16 of the 19 firms recorded returns on equity of less than 10 percent, two recorded returns between 0 and 5 percent, and 6 reported negative net income for the year.

The second table (Table 3-13) compares the performance of three sample groups. A time series on the Return on Equity was examined to determine whether the recent data are characteristic of the industry. Industry averages for the years 1977 through 1986 are 14.7 for the Chase Manhattan Group and 14.5 for the Standard & Poor Domestic integrated oil group. Thus industry returns in 1979 and 1980 are far above the industry average, and oil industry Return on Equity is returning to levels closer to historical averages from peaks established in 1980 and 1981.

The Return on Assets data (Table 3-14) show a pattern similar to the Return on Equity data. The Return on Assets for ERG's sample peaked in 1980. Note that the Return on Asset data for the sample track closely with the return on assets values for the Chase Manhattan Group and the S&P Domestic Integrated Oil Samples as shown in Table 3-15. Over the period 1977-1986, the oil industry, as measured by the three samples, generally outperformed the wider market index of 400 industrials.

In conclusion, profitability for the major integrated oil companies in 1979-1981 was high relative to typical oil industry performance since 1973. In 1982 through 1986, profitability fell to levels below the industry's historical averages. Profitability for the oil industry (as measured by Return on Assets) significantly exceeded profitability for a broader sample of industrial firms for the years 1979 to 1981.

The trend of Current Ratios for the ERG sample, as shown in Table 3-16, reflects the cash outflow caused by the rapid growth in capital and exploration expenditures between 1979 and 1981. The current ratio declined from 1.5 in 1977 to 1.1 in 1984 and 1985 as major integrated producers reduced their working capital levels to help finance their expenditure programs.

The industry's Current Ratios were also measured by other sources of financial data. The Current Ratios for the Chase Manhattan and Standard & Poor surveys are shown in Table 3-17. For S&P's sample of Domestic Integrated Oil Companies, the Current Ratio declined from 1.5 in 1977 to 1.0 in 1981, 1984 and 1985. The Chase Manhattan sample shows less of a downward trend, which may be due to the inclusion of foreign multinationals, whose currency translation effects and sources of foreign capital can offset domestic conditions to some degree. On balance, however, it appears that the average Current Ratio for the industry has declined. For both the Chase Manhattan and the S&P Groups, 1986 current ratios were higher than those recorded in 1985, as firms drastically reduced current liabilities to solidify their financial position in the face of an uncertain and hostile business climate.

The oil industry segment data compares adversely to S&P 400 Industrial data which show an average Current Ratio of 1.6 for the period 1977 to 1984. (Standard and Poor's ceased tabulating current ratio data for the 400 Industrials after 1984.) Although the industrial sample shows a declining pattern similar to that for the several oil industry samples, the S&P 400 Industrial's current ratio was consistently higher. This may result from the fact that the major integrated oil companies were better capitalized; produce products with solid, established, worldwide markets; and are generally more profitable than S&P's general industrial sample. Thus they do not require as large a reserve of working capital because they can rely on expected earnings and can borrow funds more readily.

Table 3-18 shows the Debt/Capital Ratios for the major integrated oil companies in ERG's sample for 1977-1985. Despite the large growth in exploration and capital expenditures, the debt-to-capital ratio actually reached a low in 1981, indicating the major integrated companies were not relying heavily on debt financing. In fact, debt as a percent of capital fell steadily from 1978 to 1981. It did rise in 1982, primarily attributable to the results from Getty and Occidental Petroleum. Occidental purchased Cities Service Company in 1982 and its Debt/Capital Ratio increased from 20.1 percent to 43.5 percent. The effects of the numerous mergers, takeovers, and acquisitions, as well as deteriorating market conditions in recent years, can be seen in the steady increase in the Debt/Capital ratio from 1982 through 1985.

Discussion of Real Corporate Wealth

An outstanding feature of the accounting data filed by oil companies is that reported assets and net worth may bear little relation to actual corporate wealth. This is true because the value of a firm's resource reserves is not recorded as an asset; the value of these reserves is recognized only when they enter the production process and revenues and expenses associated with their production and sale are generated. Instead, oil companies' asset accounts reflect the capitalized cost of exploration and development expenses. (That is, the value of a firm's reserves is set equal to the cost of procuring the reserves and making them ready for production.) These exploration and development costs are subsequently amortized; again, the amortization of these "assets" bears no relation to the size or value of the firm's reserves or to the timing of their consumption.

Since 1978 oil companies have been required to publish supplementary financial information relating to the size and value of their oil, gas, and other mineral reserves. This information makes it possible to estimate the total value of each firm's reserves, and to make a more realistic estimate of a firm's actual net wealth than that reflected in the balance sheet. This estimate will be flawed (for example, because firms are not required to report reserves of minerals other than oil and gas, because of uncertainties in estimates of proven reserves, and because of uncertainties in estimates of future development and production costs), but will nonetheless facilitate a much more realistic assessment of a firm's real wealth than that provided by the standard financial statements.

ERG performed a rough asset valuation for six major integrated U.S. oil companies (Amoco, ARCO, Exxon, Mobil, Shell, and Texaco), based on the supplementary reserve data published in each firm's 1986 annual report. We calculated total gross assets as the sum of the value of all reported mineral reserves (oil and gas, plus coal, sulfur, phosphate rock, and carbon dioxide, if these reserves were reported), at prices approximating year-end 1986 values, plus current assets recorded in the balance sheet. From these assets were subtracted: (1) total balance sheet liabilities; (2) the outlay required to liquidate outstanding preferred stock; (3) future oil and gas development and production costs, as estimated by each firm; and (4) estimated costs to produce other reported mineral resources (calculated as 75 percent of the estimated resource value). The result of this calculation is an estimate of the net asset value of each firm; this value is an approximation of the "liquidation value" of each firm, the net proceeds to stockholders if the firm were to be dismantled and its assets sold at current market prices.

Table 3-19 shows the results of this asset valuation process for the six American integrated oil companies specified above. The estimated gross value of the firms' mineral reserves is nearly $700 billion; with the addition of current assets, the total gross asset value of the six firms equals $749 billion. Total reported liabilities plus liquidation value of preferred stock equal $120 billion; development and production costs of reported mineral reserves are estimated to be $280 billion. Subtracting these totals from

TABLE 3-19

ESTIMATED VERSUS REPORTED NET ASSET VALUE OF SIX MAJOR U.S. INTEGRATED OIL COMPANIES, 1986

	Quant.	Units	Price	Units	Conversion	Units	Value*
GROSS ASSETS							
RESOURCE RESERVES							
Oil	20,146	MMBbl	$15.00	/Bbl Gross	1,000,000	bBL/mmbBL	$302,190,000,000
Nat Gas Liquids	876	MMBbl	$9.83	/Bbl Gross	1,000,000	Bbl/MMBbl	8,608,965,517
Nat Gas	103,9999	Bcf	$2.50	/Mcf Gross	1,000,000	Mcf/Bcf	259,997,500,000
Coal	5,400	MMtons	$22.50	/ton Gross	1,000,000	tons/MMtons	121,500,000,000
Sulfur	8,293	Mtons	$100.00	/ton Gross	1,000	tons/Mtons	829,300,000
Carbon Dioxide	7,673	Bcf	$0.45	/Mcf Gross	1,000,000	Mcf/Bcf	3,452,850,000
Phosphate	132,000	Mtons	$21.50	/ton Gross	1,000	tons/Mton	2,838,000,000
TOTAL GROSS VALUE OF RESOURCES							$699,416,615,517
CURRENT ASSETS							50,022,000,000
TOTAL GROSS VALUE OF ASSETS							$749,438,615,517
COSTS AND LIABILITIES							
Total Liabilities							($119,952,000,000)
Liquidation of Preferred Stock							(128,751,000)
Future Oil/Gas Production and Development Costs							(183,905,000,000)
Future Production/Development Costs, Other Commodities (75% of Gross Value)							(96,465,112,500)
TOTAL COSTS AND LIABILITIES							($400,450,863,500
NET ASSET VALUE							$348,987,752,017
GROSS BOOK VALUE OF ASSETS (PER 1986 BALANCE SHEET)							$215,360,000,000
SHAREHOLDER'S EQUITY (PER 1986 BALANCE SHEET)							$91,975,000,000

* 1986 dollars.

Source: ERG estimates based on values reported in the 1986 Annual Reports of six oil companies specified in the text.

estimated gross assets yields an estimated net asset value for the six firms of $349 billion.

Table 3-19 also tabulates the total book asset value and the total book value of owner's equity reported by the six oil companies in 1986. Gross reported assets were $216 billion -- less than 30 percent of the gross asset value calculated on the basis of reserves in place, and only 62 percent of the net asset value calculated on this basis. Total common shareholder's equity reported by the six firms was $92 billion. This total -- which equals the net book asset value of the firm -- is approximately one-fourth of the firms' net asset value calculated on the basis of their mineral reserves.

This alternative valuation process demonstrates that the real wealth of major American oil companies is significantly greater than that reported in their common financial disclosures. Coupled with the fact that even during periods of relative economic hardship oil companies tend to generate large cash earnings[1], this finding supports a conclusion that the financial condition of the major oil companies may be significantly stronger than a simple analysis of their published financial data indicates.

3.3.3 Ratio Analysis of Independent Companies

The decline in profits from 1980 seen for the large integrated corporations is magnified for the sample of independent producers. Of the 16 companies listed in the 1982 edition of Standard and Poor's Industry Survey for Oil, only 4 appear on the list of companies in the 1986 edition. The tenuous position of some of the latter companies is shown by the various "NM" entries in Table 3-20 through 3-23, indicating that the company was either not in existence or had a negative net income for that year. This is not to imply that the absence of a company from the 1986 list is due solely to bankruptcy; mergers and acquisitions account for most of the removals.

The return on equity for independents (Table 3-20) slides from 13 percent in 1980 to 3.9 percent in 1985. The increase seen in 1982 is due solely to the entry of Pauley Petroleum. The other measure of profitability, return on assets, shows the same downward trend, from 5.8 percent in 1981 to 1.6 percent

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[1]Standard and Poor's Industry Survey, "Oil, Basic Analysis," November 1986, p. 0-38.

TABLE 3-20

RETURN ON EQUITY (%)
INDEPENDENT OIL COMPANIES IN ERG 17-COMPANY SAMPLE

	1981	1982	1983	1984	1985
Apache Corp.	14.0	13.2	9.4	9.5	4.1
Cabot Corp.	19.6	14.1	9.7	13.9	10.6
Conquest Exploration	NM	NM	6.2	4.7	4.1
Damson Oil	12.2	7.4	5.9	13.0	NM
Hamilton Oil Corp.	9.3	3.6	5.8	6.5	9.1
Helmerich & Payne	27.7	22.5	12.4	5.2	4.4
Howell Corp.	NM	3.1	2.1	4.5	5.6
Lear Petroleum Corp.	6.8	7.3	11.3	8.5	NM
LA Land & Exploration	18.5	9.2	12.8	18.6	1.8
Mitchell Energy & Dev.	34.2	19.0	14.9	6.7	8.6
Noble Affiliates, Inc.	28.3	19.7	5.8	4.3	3.3
Pauley Petroleum	NM	NM	54.1	2.1	9.6
Plains Resources, Inc.	NM	NM	NM	10.9	2.5
Pogo Producing	26.8	18.0	7.7	5.6	NM
Sabine Corp.	16.5	12.5	18.5	4.1	2.4
Triton Energy Corp.	7.6	2.1	19.8	10.1	NM
Wainco Oil Corp.	NM	NM	7.1	0.9	NM
Unweighted Company Average[a]	13.0	8.9	12.0	7.6	3.9

NM - Not meaningful, negative net income for those years, or company not yet formed.

Source: "Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 27, 1986.

[a]Simple average calculated from the ratios of the sample.

TABLE 3-21

RETURN ON ASSETS (%)
INDEPENDENT OIL COMPANIES IN ERG 17-COMPANY SAMPLE

	1981	1982	1983	1984	1985
Apache Corp.	6.1	5.0	3.7	4.2	1.8
Cabot Corp.	9.1	6.8	4.9	6.3	4.3
Conquest Exploration	NM	NM	3.4	3.4	2.7
Damson Oil	3.4	2.7	3.0	4.7	NM
Hamilton Oil Corp.	5.4	2.5	3.0	2.5	2.9
Helmerich & Payne	16.4	13.0	7.9	3.5	3.0
Howell Corp.	NM	1.3	0.8	1.7	2.3
Lear Petroleum Corp.	2.1	1.6	3.5	3.4	NM
LA Land & Exploration	10.8	4.7	5.6	7.1	0.7
Mitchell Energy & Dev.	8.0	4.5	3.8	1.8	2.3
Noble Affiliates, Inc.	14.9	10.5	3.3	2.4	1.8
Pauley Petroleum	NM	NM	9.2	0.5	2.5
Plains Resources, Inc.	NM	NM	NM	2.4	1.6
Pogo Producing	10.2	5.9	2.7	2.2	NM
Sabine Corp.	9.6	6.3	11.1	2.9	1.6
Triton Energy Corp.	2.9	0.7	7.4	5.4	NM
Wainco Oil Corp.	NM	NM	0.9	0.2	NM
Unweighted Company Average[a]	5.8	3.9	4.4	3.2	1.6

NM - Not meaningful, negative net income, or company not yet formed.

Source: "Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 27, 1986.

[a]Simple average calculated from the ratios of the sample.

TABLE 3-22

CURRENT RATIO
INDEPENDENT OIL COMPANIES IN ERG 17-COMPANY SAMPLE

	1981	1982	1983	1984	1985
Apache Corp.	3.4	1.7	1.5	1.2	1.1
Cabot Corp.	2.2	2.2	2.6	1.8	1.9
Conquest Exploration	NA	1.1	1.4	1.0	0.7
Damson Oil	1.1	1.3	1.4	1.3	1.0
Hamilton Oil Corp.	1.9	1.7	1.4	1.4	1.2
Helmerich & Payne	1.4	1.7	3.5	3.3	4.6
Howell Corp.	1.3	1.1	1.2	1.1	1.0
Lear Petroleum Corp.	1.5	1.3	1.2	1.1	0.8
LA Land & Exploration	1.4	1.1	1.1	1.1	1.1
Mitchell Energy & Dev.	1.2	1.0	1.0	1.0	1.1
Noble Affiliates, Inc.	1.0	1.2	1.5	1.2	1.3
Pauley Petroleum	1.4	1.3	1.3	1.1	1.2
Plains Resources, Inc.	1.9	0.8	1.0	0.9	0.7
Pogo Producing	1.1	1.2	0.9	1.0	1.2
Sabine Corp.	0.9	1.6	1.7	1.2	2.3
Triton Energy Corp.	1.8	1.4	1.0	2.4	2.1
Wainco Oil Corp.	1.3	0.8	1.5	1.3	1.2
Unweighted Company Average[a]	1.5	1.3	1.5	1.4	1.4

NA - Not available.

Source: "Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 27, 1986.

[a]Simple average calculated from the ratios of the sample.

TABLE 3-23

DEBT/CAPITAL RATIO (%)
INDEPENDENT OIL COMPANIES IN ERG 17-COMPANY SAMPLE

	1981	1982	1983	1984	1985
Apache Corp.	42.6	42.4	32.6	19.6	25.3
Cabot Corp.	26.3	24.6	23.1	27.3	33.5
Conquest Exploration	NA	57.1	4.2	15.8	22.4
Damson Oil	55.7	54.2	56.3	53.3	49.2
Hamilton Oil Corp.	23.2	21.1	29.2	49.3	47.9
Helmerich & Payne	22.6	20.1	16.7	15.4	14.9
Howell Corp.	7.7	6.0	14.3	39.8	30.9
Lear Petroleum Corp.	67.2	74.1	63.9	59.1	66.7
LA Land & Exploration	27.1	25.6	36.6	34.8	31.7
Mitchell Energy & Dev.	54.4	52.4	49.6	50.0	48.1
Noble Affiliates, Inc.	22.1	19.8	17.4	15.8	19.3
Pauley Petroleum	69.1	82.9	66.3	58.7	51.9
Plains Resources, Inc.	1.0	29.3	69.3	72.2	46.3
Pogo Producing	43.7	48.1	47.9	46.0	63.0
Sabine Corp.	30.6	31.9	5.8	11.5	12.2
Triton Energy Corp.	36.2	46.9	25.8	42.7	42.3
Wainco Oil Corp.	61.3	78.6	75.3	67.1	68.1
Unweighted Company Average[a]	34.8	42.1	37.3	39.9	39.6

NA - Not available.

Source: "Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 27, 1986.

[a]Simple average calculated from the ratios of the sample.

in 1985 (Table 3-21). The impact of falling oil prices is clearly evident from these tables.

The Current Ratio data for ERG's sample of independents shown in Table 3-22 exhibits no clear overall trend. It has hovered at approximately 1.4 for the period shown. From 1981 to 1985, the Current Ratio for independents was higher than that for the majors. This indicates that the independents are financing exploration and capital expenditures with debt rather than working capital.

One reason the independents need greater liquidity is their increasing reliance on debt financing since debt covenants usually include minimum Current Ratio values. The Debt/Capital ratio hovers around 39 percent for independents (Table 3-23) compared to 26 percent for the majors (Table 3-18).

3.4 FINANCIAL PROFILES OF "TYPICAL" COMPANIES

This section reviews in more detail the performance trends and financial conditions of the two primary groups engaged in offshore petroleum development by presenting financial profiles of a "typical" major integrated company and a "typical" independent company. The financial profiles for majors are presented for selected years from 1973 to 1986. For independents, a time period of 1980- 1985 is used. To provide a basis for this analysis, financial data for six randomly selected major integrated companies[1] and three independent oil companies[2] (chosen on the basis of an examination of Pennwell Maps of offshore producers) were averaged to produce financial statements for "typical" companies. Thus, these averages reflect the relative size of the companies in the two samples. The "typical" profiles will be used in Section Seven to illustrate the potential impacts of the NSPS regulations on the two major categories of industry participants.

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[1]ARCO (Atlantic Richfield), Exxon, Mobil, Shell (Royal Dutch Petroleum), Standard Oil of Indiana (Amoco), and Texaco.

[2]Inexco Oil, Sabine Corporation and Pogo Producing.

3.4.1 Financial Profile of "Typical" Majors

Balance sheets and income statements of a "typical" major integrated oil company were prepared from the sample data. These statements are shown in Tables 3-24 and 3-25. These financial statements were then used to develop the series of performance indicators shown in Table 3-26. The more important points concerning the financial performance and condition of the "typical" major are:

1. Profitability peaked in 1980 and has declined slowly thereafter as shown by the return on assets and return on equity values.

2. Working capital declined after 1980, with a negative net working capital shown in 1985. The current ratio (the ratio of current assets to current liabilities) fell from 1.53 in 1973 to 0.93 in 1985 before recovering somewhat in 1986.

3. Despite the ambitious capital spending program of the "typical" major, both the long-term debt-to-equity and debt-to-capital ratios actually declined from 1976 to 1982, indicating that the "typical" major was not acquiring debt to finance its capital spending program. Apparently, the effect of large increases in exploration and capital expenditures fell more heavily on the major's working capital or equity financing than it did on the level of debt financing.

This situation changed markedly in 1984 and 1985 when both the long-term debt-to-equity and debt-to-capital ratios jumped 9 percent and 54 percent from 1983 levels respectively. The majors are becoming increasingly leveraged in response to or as a result of recent corporate takeover actions.

3.4.2 Financial Profile of "Typical" Independents

Financial Performance of a "Typical" Independent

A balance sheet and income statement of a "typical" independent oil company for the years 1980-1985 are provided in Tables 3-27 and 3-28. These financial statements were then used to develop the series of performance indicators in Table 3-29. Data for 1986 were not developed because one of the three independents analyzed (Inexco) was acquired by the Louisiana Land and Exploration Company during 1986, and ceased publishing financial data. The "disappearance" of Inexco is emblematic of the financial difficulties which have beset independents since oil and natural gas prices started to slide in the early 1980s. Firms have been trapped by the need to finance aggressive exploration and development programs while their annual revenues have

TABLE 3-24

BALANCE SHEET FOR A "TYPICAL" MAJOR INTEGRATED OIL COMPANY (IN MILLIONS OF CURRENT DOLLARS)

	1973	1976	1978	1980	1981	1982	1983	1984	1985	1986
Assets										
Current Assets	3,841	6,435	7,330	10,609	10,610	9,332	8,931	8,665	8,903	8,337
Property, Plant and Equipment (Net)	6,499	9,135	11,428	16,013	18,450	20,445	21,377	24,323	25,145	24,799
Other Assets	805	1,296	1,411	1,728	2,049	2,412	2,440	2,727	2,722	2,758
Total Assets	11,145	16,866	20,169	28,350	31,109	32,189	32,748	35,715	36,770	35,893
Liabilities										
Current Liabilities	2,506	4,706	5,495	8,229	8,488	7,717	7,335	8,001	9,529	7,536
Long-Term Debt	1,463	2,377	2,620	3,064	3,385	3,414	3,972	6,180	5,652	5,443
Other Liabilities[a]	883	1,457	2,494	4,402	5,115	6,228	5,974	6,437	6,916	7,600
Total Liabilities	4,852	8,540	10,609	15,695	16,988	17,359	17,280	20,619	22,097	20,579
Shareholder's Equity	6,293	8,326	9,560	12,655	14,121	14,830	15,468	15,096	14,673	15,314
Total Liabilities and Net Worth	11,145	16,866	20,169	28,350	31,109	32,189	32,748	35,715	36,770	35,893

[a]Other liabilities include: deferred Federal and foreign income taxes, deferred revenue, production payments, and other medium-term commitments.

Source: Annual Reports for ARCO, Exxon, Mobil, Shell, Standard Oil of Indiana (Amoco), Texaco. Component items may not add to totals due to rounding. Balance sheet items for "typical" company are calculated by single averaging of balance sheet items for the six major integrated oil companies in the sample.

TABLE 3-25

INCOME STATEMENT FOR A "TYPICAL" MAJOR INTEGRATED OIL COMPANY (IN MILLIONS OF CURRENT DOLLARS)

	1973	1976	1978	1980*	1981	1982	1983	1984	1985	1986
Revenues	11,624	23,134	28,633	49,795	54,170	48,861	44,902	46,802	45,570	35,395
Expenses	9,438	20,139	25,334	44,672	49,502	45,093	37,824	39,701	38,741	29,430
Depletion, Depreciation, and Amortization	554	735	951	1,328	1,592	1,774	1,958	2,440	2,541	2,630
Income Before Income Taxes	2,186	2,995	3,299	5,123	4,668	3,768	7,078	7,101	6,829	5,965
Income Taxes	1,236	1,893	2,060	2,537	2,191	1,776	4,951	5,164	5,072	4,343
Net Income	950	1,102	1,239	2,586	2,477	1,992	2,127	1,937	1,757	1,623

*Excludes extraordinary income related to sale of an oil company.

Source: Annual Reports for ARCO, Exxon, Mobil, Shell, Standard Oil of Indiana, Texaco. Component items may not add to totals due to rounding. Income statement items for "typical" company are calculated by averaging income statement items for the six major integrated oil companies in the sample.

TABLE 3-26

FINANCIAL RATIO AND PERFORMANCE INDICATORS FOR A "TYPICAL" MAJOR INTEGRATED OIL COMPANY

RATIOS AND PERFORMANCE INDICATORS	1973	1976	1978	1980	1981	1982	1983	1984	1985	1986
Net Working Capital ($M)	1,335	1,729	1,835	2,380	2,122	1,615	1,597	664	(626)	801
Current Ratio	1.53	1.37	1.33	1.29	1.25	1.21	1.22	1.08	0.93	1.11
Long-Term Debt to Equity Ratio (%)	23.2	28.5	27.4	24.2	24.0	23.0	25.7	40.9	38.5	35.5
Debt to Capital Ratio (%)	16.6	18.2	17.4	14.7	15.0	15.1	17.4	26.8	23.4	23.8
Return on Year-End Assets (%)	8.5	6.5	6.1	9.1	8.0	6.2	6.5	5.4	4.8	4.5
Return on Year-End Equity (%)	15.1	13.2	13.0	20.4	17.5	13.4	13.8	12.8	12.0	11.1
Return on Revenues(%)	8.2	4.8	4.3	5.2	4.6	4.1	4.7	4.1	3.9	3.6

Source: ERG estimates.

TABLE 3-27

BALANCE SHEET FOR A "TYPICAL" INDEPENDENT OIL COMPANY
(Millions of Current Dollars)

	1980	1981	1982	1983	1984	1985
Assets						
Current Assets	55	87	71	55	55	53
Property, Plant and Equipment (net)	387	543	647	613	626	528
Other Assets	5	5	4	4	4	3
TOTAL ASSETS	447	635	722	671	686	583
Liabilities						
Current Liabilities	52	82	64	51	47	49
Long-term Debt	148	246	311	269	280	268
Other Liabilities	46	73	102	139	152	108
TOTAL LIABILITIES	247	401	477	459	479	424
Shareholder's Equity	200	233	245	212	207	159
TOTAL LIABILITIES AND NET WORTH	447	635	722	671	686	583

Source: Annual reports for Inexco, Pogo Producing, and Sabine. Component items may not add to totals due to independent rounding. Balance sheets for "typical" company are calculated by simple averaging of balance sheet items for three independent oil companies.

TABLE 3-28

INCOME STATEMENT FOR A "TYPICAL" INDEPENDENT OIL COMPANY
(Millions of Current Dollars)

	1980	1981	1982	1983	1984	1985
Revenue	164	236	231	172	179	161
Expenses	106	163	181	133	176	239
Depletion, Depreciation, and Amortization	51	65	75	71	71	69
Income Before Taxes	58	73	50	39	3	(78)
Net Income	34	42	31	24	3	(41)
Domestic Exploration and Development Expenditures[a]	193	187	173	101	105	69

Source: Annual reports for Inexco, Pogo Producing, and Sabine. Component items may not add to totals due to independent rounding. Balance sheets for "typical" company are calculated by simple averaging of balance sheet items for three independent oil companies.

[a]Defined as sum of property acquisition, exploration, and development expenditures.

TABLE 3-29

FINANCIAL RATIOS AND PERFORMANCE INDICATORS FOR A "TYPICAL" INDEPENDENT OIL COMPANY

RATIOS AND PERFORMANCE INDICATORS	1980	1981	1982	1983	1984	1985
Net Working Capital ($M)	3	5	7	3	9	4
Current Ratio	1.05	1.06	1.12	1.06	1.19	1.08
Long-Term Debt to Equity Ratio (%)	74.2	105.4	127.2	126.9	135.3	168.3
Debt to Capital Ratio (%)	58.8	77.9	101.0	102.2	110.4	128.7
Return on Year-End Assets (%)	7.6	6.6	4.3	3.6	0.4	NM
Return on Year-End Equity (%)	17.0	18.0	4.3	11.3	1.4	NM
Return on Revenues (%)	20.7	17.8	9.1	14.0	1.7	NM

NM - Not meaningful, negative net income for 1985.

Source: ERG estimates.

declined; an unprecedented volume of merger and takeover activity has been the direct result.

The most important points about the financial performance and condition of the "typical" independent are:

1. Profitability results were mixed over the period. From 1976 through 1981, net income and return on equity increased. In 1982, net income, return on equity, and return on assets began to decrease until they reached 1985 levels with a negative net income.

2. The current ratio, which greatly declined in the early eighties from the seventies, rose slightly in 1982 and 1984. Working capital fluctuates during 1980-1985 period.

3. Both the long-term debt-to-equity and debt-to-capital ratios in the mid- 1980's climbed substantially from 1980 values. The amount of long-term debt increased 80 percent from 1980 to 1985. Clearly, the "typical" independent used a large amount of debt financing to fund its exploration and development programs, leaving it in a much more highly leveraged position in 1985 than in 1980, and substantially higher than the majors.

3.4.3 Financial Comparisons Among "Typical" Oil Companies

This section uses the data developed in the previous sections as the basis for comparing the financial performance and condition of "typical" majors and independents. These comparisons will provide insight into the potential financial problems the different types of oil companies have faced or may face in the future.

<u>Profitability</u>

From 1980 through 1985, the typical major performed consistently better than the typical independent with respect to higher returns on equity and assets, yet the independent made more on each dollar of revenue than did the major as shown by the Profitability index (returns or revenues, see Table 3-30). From 1980 to 1984, return on assets declined 7.2 percentage points for the independent versus 3.7 percentage points for the major. For the same period, return on equity fell 15.6 percentage points for the independent as opposed to only a 7.6-point drop for the major.

The effects of reduced demand and lower wellhead prices can be clearly seen in drop in profitability for both major and independent companies. Majors reduced capital and exploration expenditures after 1982, due to

TABLE 3-30

PROFITABILITY COMPARISONS BETWEEN "TYPICAL" OFFSHORE OIL COMPANIES

	1980	1981	1982	1983	1984	1985
Return on Year-End Assets (%)						
Major Integrated Company	9.1	8.0	6.2	6.5	5.4	4.8
Independent Company	7.6	6.6	4.3	3.6	0.4	NM
Return on Year-End Equity (%)						
Major Integrated Company	20.4	17.5	13.4	13.8	12.8	12.0
Independent Company	17.0	18.0	4.3	11.3	1.4	NM
Return on Revenues (%)						
Major Integrated Company	5.2	4.6	4.1	4.7	4.1	3.9
Independent Company	20.7	17.8	9.1	14.0	1.7	NM

NM = Not meaningful, negative net income in 1985.

Source: ERG estimates.

dropping demand and price (see Sections 3.2.1 and 3.2.2). The lower crude prices in 1985 cut refining and chemical feedstock costs for the downstream operation of the majors. Lower crude prices lead to losses on upstream operations. For the majors, downstream savings offset upstream losses. Independents have no downstream operations to mitigate the financial detriment caused by lower crude prices on upstream operations. In addition, independents are more highly leveraged than the majors, and the drop in oil prices devalues their proven reserves, thereby creating pressure to pay back a portion of their long-term debt.

Liquidity

The typical major relied more heavily on working capital rather than outside borrowings to finance its capital and exploration expenditures from 1980 to 1985. The level of working capital fell during this period and the current ratio dropped from 1.29 in 1980 to 0.93 in 1985 (Table 3-31). The "typical" independent saw its current ratio fluctuate between 1.05 and 1.19 during 1980- 1985. The overall financial strength of the majors relative to the independents is evident by the way they have maintained higher levels of profitability than independents in a declining oil-price market. The major can usually borrow in the short term and raise funds with relative ease. Therefore, the majors' current ratios can be less than the independents' and still be considered healthy. Yet the current ratio for independents tends to be lower than that for the majors during the 1980-1985 period.

Leverage

The independent companies are more highly leveraged than the major companies especially in the 1980's. Data relating to past and existing capital structures are summarized in Table 3-32.

As most oil companies embarked on ambitious exploration and capital spending programs in the early 1980's, the independents financed these programs primarily through the issue of long-term debt. As can be seen for the period 1980 to 1982, the long-term debt-to-equity ratio had actually declined for the typical major, in contrast to an increase of almost 50 percent for the typical independent. In 1985, the Debt/Equity Ratio was 5.5 times as high for the typical independent as for the major. The Debt/Capital Ratio parallels the long- term Debt/Equity Ratio.

TABLE 3-31

LIQUIDITY COMPARISONS BETWEEN "TYPICAL" OFFSHORE OIL COMPANIES

	1980	1981	1982	1983	1984	1985
Current Ratio						
Major Integrated Company	1.29	1.25	1.21	1.22	1.08	0.93
Independent Company	1.05	1.06	1.12	1.06	1.19	1.08
Change in Working Capital Capital (%)						
Major Integrated Company	--	-0.1	-0.2	0.0	-0.6	NM
Independent Company	--	0.7	0.4	-0.6	2.0	-0.6

NM - not meaningful, negative net working capital in 1985.

Source: ERG estimates.

TABLE 3-32

LEVERAGE COMPARISONS BETWEEN "TYPICAL" OFFSHORE OIL COMPANIES

	1980	1981	1982	1983	1984	1985
Long-Term Debt to Equity Ratio (%)						
Major Integrated Company	24.2	24.0	23.0	25.7	40.9	38.5
Independent Company	74.2	105.4	127.2	126.9	135.3	168.3
Debt to Capital Ratio (%)						
Major Integrated Company	14.7	15.0	15.1	17.4	26.8	23.4
Independent Company	58.8	77.9	101.0	102.2	110.4	128.7
Equity to Total Assets (%)						
Major Integrated Company	44.6	45.4	46.1	47.2	42.3	39.9
Independent Company	44.7	36.7	33.9	31.6	30.2	27.3

Source: ERG estimates.

The other data in Table 3-32 serve to amplify this observation. Equity to total assets is a measure of how soundly capitalized is the company. The higher the proportion of equity, the greater is its buffer against short-term losses, and the greater is its ability to take on more debt to finance future expenditures. The data show that this ratio improved somewhat for the "typical" major from 1980 to 1983, in spite of large exploration and capital expenditure programs. In contrast, the ratio has declined steadily for the typical independent from 1980 to 1985.

Growth and Spending

The major and independent companies were also compared in terms of revenue growth and expenditure programs. Table 3-33 displays these comparisons.

The recent spending programs of the majors were less sensitive to price and demand fluctuations than the independents' programs since the majors need to keep the product pipeline filled. The majors, as part of their long-range production and reserve acquisition plans, attempt to maintain relative stability in their exploration spending goals and have more financial flexibility to vary their sources of funds. The relative volatility of the independents' plans is increased by their more highly leveraged positions. In a downturn, the independents must reduce expenditures more sharply in order to limit further new debt-financing costs.

Another comparison is the difference in exploration and development expenditures as a percent of total revenues. Independents are more focused on domestic exploration and development (although a few have diversified into overseas development, refining, pipelines, and other minerals). This fact is apparent in the data shown. Domestic exploration and production expenditures as a percent of revenues for the "typical" major between 1980 and 1982 ranged between 8.5 and 11 percent. In contrast, the percentage for the "typical" independent ranged between 42.9 and 118 percent.

TABLE 3-33

GROWTH AND SPENDING COMPARISONS BETWEEN "TYPICAL" OFFSHORE OIL COMPANIES

	1980	1981	1982	1983	1984	1985
Growth in Domestic Oil and Gas Exploration and Development Expenditures (Capitalized and Expensed) (%)						
Major Integrated Company	--	8.0	3.3	-22.1	9.2	3.5
Independent Company	--	3.11	-7.49	-41.62	3.96	-34.29
Change in Total Revenues (%)						
Major Integrated Company	--	8.8	-9.8	-8.1	4.2	-2.6
Independent Company	--	43.9	-2.1	-25.5	4.1	-10.1
Domestic Oil and Gas Exploration and Development Expenditures as a Percent of Total Revenues (%)						
Major Integrated Company	8.5	9.8	11.0	9.8	10.3	11.0
Independent Company	117.7	79.2	74.9	58.7	58.7	42.9

Source: ERG estimates.

Note: All values calculated from current dollar data.

3.5 FINANCIAL CONDITION IN 1986 AND FUTURE OUTLOOK

3.5.1 1986 Financial Performance

The analysis can be updated further using recent financial reports. Net income for 25 large U.S. oil companies during 1986 was down 33.4 percent from 1985. The continued fall of oil and gas prices caused a 23.9 percent decline in group revenues in 1986. Capital and exploration outlays were down 33.4 percent from the 1985 levels. The main reasons are lower oil prices, write downs of assets and continued restructuring for these companies. The drop in revenues occurred mainly in upstream operations, while downstream earnings were up for most companies in the group. Lower crude prices reduce refining and chemical feedstock costs, thereby increasing earnings from downstream operations.[1]

Prospects for the future are mixed. On the plus side, 1986 saw an increase in demand for petroleum products, and demand increased again in 1987.[2] The uncertainty about tax reform is over, and the industry did not fare as poorly as it had feared.[3] Oil and natural gas prices stabilized during 1987. World production continues to exceed demand, however, so prices are unlikely to rise significantly in the short term.[4] Continued low prices should foster additional demand growth, which in turn should pull prices higher, but this effect may not occur for several years. For companies with downstream operations, continued lower oil prices will benefit earnings from those operations, particularly if demand goes up. For independents, with no downstream operations, the short-term outlook is not very positive.

3.5.2 Future Strategy for the Majors

The realization that they are faced with a declining demand trend has led the major oil companies to make major adjustments to spending strategies since 1981. Companies have redirected their focus from long-term plans designed to

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[1]Oil and Gas Journal, May 25, 1987.

[2]Oil and Gas Journal, January 25, 1988.

[3]"Oil, Basic Analysis," Standard and Poor's Industry Survey, November 27, 1986.

[4]Oil and Gas Journal, January 25, 1988.

maximize asset values to concentrating more on increasing short-run cash flows. An Oil and Gas Journal article reports that since 1981, companies have streamlined operations by cutting payrolls, reducing surplus refining capacity, and halting marketing operations in areas of marginal value. Many companies have reduced debt and sold assets with little short-term potential for revenue.[1] Following an average 44.6 percent drop from 1985 to 1986, capital and exploration expenditures declined an additional 5.6 percent in 1987. With stabilizing oil and gas prices, however, most producers plan to expand development and exploration activity in 1988.[2]

A number of factors have combined to create a mixed environment for major, integrated firms. Many firms diversified in the late 1970's and early 1980's. By the mid 1980's, many of these diversifications have been either shut down, spun off to shareholders, or written down (e.g., synfuels). The takeover activity of recent years has also led to the majors becoming increasingly financially leveraged.[3] Low oil prices have resulted in drastic cutbacks in exploration and development activity, essentially since it has been less expensive for the majors to increase oil imports than to locate and develop new resources. The curtailment of exploration programs has been reflected graphically in the lack of interest in recent OCS lease sales, and in the very low bids offered for Federal OCS lease tracts (see Table 2-2).

With rising demand, rising oil imports, and a severely depressed domestic exploration program, the U.S. may have prepared the ground for another "oil crisis" in coming years. The financially strong companies are in a position to obtain productive properties from financially distressed companies and to be in an excellent position when the seller's market returns; weaker companies may need to sell off assets or merge with financially stronger companies.

3.5.3 Future of the Independents

The financial outlook for the independent oil companies is less optimistic than that for the majors. Many independents borrowed heavily in recent years in order to finance new operations. In doing so they essentially mortgaged

[1]Oil and Gas Journal, February 28, 1983.

[2]Oil and Gas Journal, March 28, 1988.

[3]"Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 27, 1986.

their future against crude oil and natural gas reserves, expecting that the value of these reserves would steadily increase. Until late in 1981, it was common practice for companies and commercial lenders to assume that the price of crude would increase significantly faster than inflation during the term of any loan. This meant that the value of oil and gas reserves used to secure debt was set at a higher amount for loan purposes than their actual market values. Borrowing was done on the assumption that higher crude prices in the future would cover the debt accrued in the present.

When the price of crude oil fell and demand for natural gas slumped, the calculated market value of the reserves fell. Lenders found themselves with loans that were not completely secured by reserve values, and asked for partial loan repayments or increased collateral. This put the independents in the position of having to pay back both principal and interest on their loans at a time of reduced earnings and cash flow, resulting in the failure of some small independents.

In addition to financing troubles, the independents have other problems. In general, independents have traditionally concentrated much more on natural gas production than oil, and the prospects for recovery in the oil segment are brighter than for gas. Those independents which have provided contract drilling services are also suffering from a low rig utilization rate. The utilization rate, which peaked at 98 percent in 1981, had fallen to under 40 percent in March of 1983.[1] The number of active rigs peaked at 3,974 in 1981; 1986 saw an average of 965 active rigs per week.[2] For many independents, idle rigs represent a significant amount of depreciating capital tied up with no economic use and little collateral value.

The impact of these conditions on the growth and survival of firms within the industry has been mixed. Many small firms have gone bankrupt or have been purchased by stronger companies in the past year. Other producers are attempting to restructure debts, sell assets, or merge with other companies. Independents who are financially secure are in a good position to grow stronger by acquiring acreage from other independents at bargain prices. Onshore production costs have also declined sharply due to the slack in demand for oil field services and equipment.

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[1]Oil and Gas Journal, April 4, 1983; "Oil, Basic Analysis," Standard and Poor's Industry Survey, November 27, 1986.

[2]Oil and Gas Database, Hughes Rig Count, 1970-1986, requested March 1987.

In summary, the financial position of most independents will prohibit them from participating at the same level in exploration and development programs as they did in 1979-1981. If the independent is in the position to consider development at all, it will more likely focus on development onshore rather than offshore. Most independents are in a financially weaker condition than the majors.[1]

[1]"Oil, Basic Analysis," Standard and Poor's Industry Surveys, November 27, 1986.

SECTION FOUR

WELL AND PLATFORM PROJECTIONS

This section presents projections of offshore oil and gas activity for the 1986-2000 time period. These projections are used in later sections to calculate total costs of the alternative regulatory approaches for BAT and NSPS. The projections presented below begin with the Minerals Management Service (MMS) production projections (Section 4.1) which serve as a basis for the well projections (Section 4.2). The MMS projections are presented for three oil price variations: $15/bbl, $21/bbl, and $32/bbl. From these forecasts, ERG developed two different platform projections: an unrestricted development scenario (Section 4.3) and a restricted development scenario (Section 4.4).[1] Finally the projections are summarized in Section 4.5. In Sections 4.1 and 4.2, tables labeled "a" (i.e., 4-1a) refer to the $32/bbl, tables labeled "b" refer to the $21/bbl scenario, and tables labeled "c" refer to the $15/bbl scenario. The oil prices are in 1986 dollars.

The forecasts of Federal water activity are based on MMS production projections. The State water forecasts are based on an analysis of State water activity from 1980-1985 for the Pacific and Alaskan regions and 1967-1985 for the Gulf region. Together these forecasts make up the unrestricted development scenario which represents the high end of expected offshore activity during the 1986-2000 time period (i.e., all resources that are economically feasible to be developed will be.) A restricted development scenario has been created based upon the same MMS projections, but altered to account for recent moratoria on offshore oil and gas leasing and development in the Pacific and Atlantic regions. This projection represents the lowest case scenario of the amount of offshore activity that will be occurring from 1986-2000.

Based upon the two patterns of development and three alternative oil prices, ERG analyzed four alternative scenarios:

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[1]The terms "unrestricted" and "restricted" as used throughout this report correspond to "unconstrained" and "constrained" as used in the preamble to the proposed rulemaking.

- Unrestricted development:
  - \$21/bbl
  - \$32/bbl (This represents the high end of development.)

- Restricted development:
  - \$21/bbl
  - \$15/bbl (This represents the low end of development.)

This approach assures that the entire range of potential regulatory costs have been addressed.

4.1 PROJECTED OCS OIL AND GAS PRODUCTION, 1986-2000

4.1.1 MMS Projections

The OCS forecast was developed using the MMS 30-year projections of oil and gas production (MMS, 1985a). MMS developed this forecast from data in its Environmental Impact Statement for the Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program Mid-1987 to Mid-1992 (MMS, 1986). In that report, MMS estimated "conditional resources" for 21 OCS regions, assuming a market value of \$32 per barrel of oil. These conditional resources represent the mean amount of oil and gas reserves that are economically recoverable from the leased areas, given that exploration confirms the presence of hydrocarbon reserves. The probability of finding reserves varies from region to region. An estimate of the resources expected to be developed in each leased area can be obtained by multiplying the probability of finding reserves (estimated by MMS) by the conditional resource estimates. Using this risked resource estimate, and rules of thumb regarding the amount of time it takes to develop the resources in each area, MMS has developed a schedule of resource production for the mid-1987 to mid-1992 lease sale.

To develop the full 30-year projections at \$32 per barrel, MMS utilized its estimates of the percentage of undeveloped resources to be leased during each of its subsequent leasing periods. For example, if 25 percent of Alaska's resources are expected to be leased in 1987-1991, and 25 percent of Alaska's resources are to be leased in 1992-1996, then the resource projections for the 1992-1996 period would replicate the resource projections from the 1987-1991 period, with a 5-year lag. If 50 percent of Alaska's resources were to be leased in 1992-1996, then the projections would be double those for the 1987-1991 period.

Based on this methodology, MMS has published 30-year projections of OCS oil and gas production for four major regions: the Atlantic, Gulf of Mexico, Pacific, and Alaska. These projections were selected for this analysis for the following reasons. First, the MMS forecast is based on a disaggregated analysis of risked resource potential and lease sale activity in each of the four regions. Second, the forecast extends to 2015; many forecasts do not extend beyond 1995. This report is concerned with the period 1986-2000; the use of actual projections for 1995-2000 increases their accuracy. Finally, the MMS forecast is easily amenable to different price scenarios. In its Secretarial Issue Document (SID), MMS developed alternative leasable resource estimates for various prices.[2] Based on these resource estimates, the ratio of resources at $21 to $32 per barrel, and $15 to $32 per barrel are as follows:

Region	Ratio of $21/bbl to $32/bbl Resources	Ratio of $15/bbl to $32/bbl Resources
Gulf	0.965	0.858
Pacific	0.790	0.541
Atlantic	0.514	0.327
Alaska	0.098	0.0

These ratios mean, for example, that using the MMS resource estimates for the Pacific OCS at $32 per barrel (i.e., MMS projections at $32 per barrel equal 100 percent), the Agency estimates that 79 percent of these Pacific resources would be developed if the price of oil fell to $21 per barrel. Similarly, if the price fell from $32 to $15 per barrel, the Agency projects that it would make economic sense for the oil and gas industry to develop 54.1 percent of these Pacific resources. These ratios were used to develop alternative forecasts from the $32 per barrel forecast.

Table 4-1 presents the MMS production projections. Table 4-1a, the $32 scenario, was derived from the 30-year forecast developed by MMS. OCS oil production for 1990 is estimated at 1.2 million barrels per day. Gas production for 1990 is estimated at 3.5 trillion cubic feet. Table 4-1b was developed by ERG based upon Table 4-1a and the ratios developed from MMS's Secretarial Issue Document. As shown in Table 4-1b, oil production in 1990 is approximately 10 percent lower under the $21 scenario than the $32 scenario. Gas production is approximately 4 percent lower under the $21 scenario than

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[2]See MMS 1987, Appendix F, p. F-75. The oil prices in the SID are in $1984 and are listed as $14, $19, and $29 scenarios. ERG estimated 1986 prices based on world oil prices, a 5 percent inflation rate, and a 1 percent real growth rate to obtain the $15, $21, and $32 scenarios, respectively.

TABLE 4-1a

MMS FEDERAL OCS MODEL OUTPUTS: TOTAL 1990, 1993, 1995, AND 2000 PRODUCTION

($32/bbl of oil - 1986 dollars)

	OIL PRODUCTION (BARRELS PER DAY)				GAS PRODUCTION (TRILLIONS OF CUBIC FEET PER YEAR)			
REGION	1990	1993	1995	2000	1990	1993	1995	2000
Gulf of Mexico	822,000	836,000	882,000	877,000	3.36	3.15	3.22	3.2
Pacific	356,000	411,000	425,000	370,000	0.14	0.21	0.24	0.31
Atlantic	0	68,000	55,000	41,000	0	0.41	0.31	0.24
Alaska	0	0	96,000	384,000	0	0	0.07	0.21
Total	1,178,000	1,315,000	1,458,000	1,672,000	3.5	3.77	3.84	3.96

Source: 30-Year Projections of Oil and Gas Production from the United States Outer Continental Shelf Areas, as transmitted by Chief, Offshore Resource Evaluation Division, MMS, to Associate Director for Offshore Minerals Management, December 2, 1985. The MMS data were provided in a graphic format. The numeric amounts were then estimated by ERG.

TABLE 4-1b

MMS FEDERAL OCS MODEL OUTPUTS: TOTAL 1990, 1993, 1995, AND 2000 PRODUCTION

($21/bbl of oil - 1986 dollars)

	OIL PRODUCTION (BARRELS PER DAY)				GAS PRODUCTION (TRILLIONS OF CUBIC FEET PER YEAR)			
REGION	1990	1993	1995	2000	1990	1993	1995	2000
Gulf of Mexico	793,000	807,000	851,000	846,000	3.24	3.04	3.11	3.09
Pacific	281,000	325,000	336,000	292,000	0.11	0.17	0.19	0.24
Atlantic	0	35,000	28,000	21,000	0	0.21	0.16	0.12
Alaska	0	0	0	0	0	0	0.01	0.02
Total	1,074,000	1,167,000	1,224,000	1,197,000	3.35	3.42	3.47	3.47

Source: ERG estimates based upon the MMS Secretarial Issue Document, Final Draft, Appendix F, p. F-75, 1986 and the 30-Year Projections of Oil and Gas Production from the United States Outer Continental Shelf Areas, as transmitted by Chief, Offshore Resource Evaluation Division, MMS, to Associate Director for Offshore Minerals Management, December 2, 1985.

TABLE 4-1c

MMS FEDERAL OCS MODEL OUTPUTS: TOTAL 1990, 1993, 1995, AND 2000 PRODUCTION

($15/bbl of oil - 1986 dollars)

REGION	OIL PRODUCTION (BARRELS PER DAY) 1990	1993	1995	2000	GAS PRODUCTION (TRILLIONS OF CUBIC FEET PER YEAR) 1990	1993	1995	2000
Gulf of Mexico	705,000	717,000	757,000	752,000	2.88	2.70	2.76	2.75
Pacific	193,000	222,000	230,000	200,000	0.08	0.11	0.13	0.17
Atlantic	0	22,000	18,000	13,000	0	0.13	0.10	0.08
Alaska	0	0	0	0	0	0	0	0
Total	898,000	961,000	1,005,000	965,000	2.96	2.94	2.99	3.00

Source: ERG estimates based upon the MMS Secretarial Issue Document, Final Draft, Appendix F, p. F-75, 1986 and the 30-Year Projections of Oil and Gas Production from the United States Outer Continental Shelf Areas, as transmitted by Chief, Offshore Resource Evaluation Division, MMS, to Associate Director for Offshore Minerals Management, December 2, 1985.

the $32 scenario. Table 4-1c, the $15 scenario, shows that in 1990 oil production is 31 percent lower and gas production is 18 percent lower than under the $32 scenario.

4.1.2 Pre-1986 Production

Pre-1986 production is defined as all production from wells drilled prior to 1986. Oil and gas wells typically produce at an initial peak level, and production gradually declines with time. Therefore, in order to calculate production in years following 1986, the initial rate of production, years at peak production, and the production decline rate must be specified. To estimate the production from pre-1986 sources, the following values were assumed:

	Initial Rate of Production	Years at Peak Production	Decline Rate
Oil Production	Barrels/Day	Years	Percent
Gulf	500	2	15
Pacific	900	2	33
Atlantic	1,000	2	15
Alaska	1,960	2	10
Gas Production	MMCFD	Years	Percent
Gulf	4.0	4	15
Pacific	5	4	22
Atlantic	7.5	8	15
Alaska	15	16	15

The initial rates of production and the number of years at peak production are based primarily on data presented in a previous report (EPA, 1985). However, the initial rates of oil production in the Pacific and gas production in the Gulf are based on data provided by MMS. The decline rates were developed from several information sources. For example, the MMS projections use a 40 percent decline rate for oil and a 25 percent decline rate for gas in southern and central California (MMS, 1985b). Field data provided by the Department of Energy indicated these rates may be high (DOE, 1989). ERG, therefore, lowered the decline rates to 33 percent and 22 percent for oil and gas, respectively. In the case of Alaska, MMS used unique decline rates for each year of production; the ERG analysis uses 10 percent and 15 percent for oil and gas, respectively, which are the averages of the MMS decline rates (MMS, 1985b).

Table 4-2 shows the OCS production from pre-1986 sources over time. There is currently no OCS production in the Atlantic or Alaska regions. In Table 4-2a, pre-1986 oil production declines from 491,000 barrels per day in 1990 to 94,000 barrels per day in 2000. Pre-1986 gas production declines from 2.48 trillion cubic feet in 1990 to 0.49 trillion cubic feet in 2000. Tables 4-2b and 4-2c show similar decline patterns for the other two scenarios.

4.1.3 Future OCS Production from 1986 and Later Sources

Production levels in 1986 and after were developed by subtracting the pre-1986 sources of production (Table 4-2) from total projected production (Table 4-1). Table 4-3 illustrates this calculation for total production. Under the $32 scenario, oil production from wells drilled in 1986 and later will rise from 687,000 barrels per day in 1990 to 1,578,000 barrels per day in 2000. Gas production will rise from 1.02 trillion cubic feet in 1990 to 3.47 trillion cubic feet in 2000. Tables 4-3b and 4-3c document similar, though lower, production figures for the $21 and $15 scenarios for 1986 and later.

Table 4-4 shows the 1986 and later sources of production for each of the four regions. These production amounts were developed in the same manner as the total 1986 and later production levels shown in Table 4-3.

4.2 FORECAST OF OFFSHORE OIL AND GAS WELLS, 1986-2000

Alternative regulatory approaches for drilling fluids and drill cuttings affect both productive and unproductive drilling efforts. In order to distinguish between the two, the number of productive wells in Federal and State waters are forecast and then the proportion of dry holes is estimated based on historical data of offshore drilling efforts. The combination of these forecasts provides the average number of offshore wells drilled for the 1986-2000 time period.

TABLE 4-2a

OCS PRODUCTION FROM PRE-1986 SOURCES
($32/bbl of oil - 1986 dollars)

	OIL PRODUCTION (BARRELS PER DAY)			GAS PRODUCTION (TCF/YEAR)		
YEAR	GULF[a]	PACIFIC[b]	TOTAL	GULF[a]	PACIFIC[c]	TOTAL
1990	480,000	11,000	491,000	2.47	0.01	2.48
1993	295,000	3,000	298,000	1.52	0	1.52
1995	213,000	1,000	214,000	1.1	0	1.1
2000	94,000	0	94,000	0.49	0	0.49

Source: ERG estimates based upon pre-1986 production levels in the MMS forecast.

[a]Calculated using a 15 percent annual decline rate.

[b]Calculated using a 33 percent annual decline rate.

[c]Calculated using a 22 percent annual decline rate.

TABLE 4-2b

OCS PRODUCTION FROM PRE-1986 SOURCES
($21/bbl of oil - 1986 dollars)

	OIL PRODUCTION (BARRELS PER DAY)			GAS PRODUCTION (TCF/YEAR)		
YEAR	GULF[a]	PACIFIC[b]	TOTAL	GULF[a]	PACIFIC[c]	TOTAL
1990	463,000	9,000	472,000	2.38	0.01	2.39
1993	285,000	2,000	287,000	1.47	0	1.47
1995	206,000	1,000	207,000	1.06	0	1.06
2000	91,000	0	91,000	0.47	0	0.47

Source: ERG estimates based upon pre-1986 production levels in the MMS forecast.

[a]Calculated using a 15 percent annual decline rate.

[b]Calculated using a 33 percent annual decline rate.

[c]Calculated using a 22 percent annual decline rate.

TABLE 4-2c

OCS PRODUCTION FROM PRE-1986 SOURCES
($15/bbl of oil - 1986 dollars)

	OIL PRODUCTION (BARRELS PER DAY)			GAS PRODUCTION (TCF/YEAR)		
YEAR	GULF[a]	PACIFIC[b]	TOTAL	GULF[a]	PACIFIC[c]	TOTAL
1990	412,000	6,000	418,000	2.12	0.01	2.13
1993	253,000	2,000	255,000	1.30	0	1.3
1995	183,000	1,000	184,000	0.94	0	0.94
2000	81,000	0	81,000	0.42	0	0.42

Source: ERG estimates based upon pre-1986 production levels in the MMS forecast.

[a]Calculated using a 15 percent annual decline rate.

[b]Calculated using a 33 percent annual decline rate.

[c]Calculated using a 22 percent annual decline rate.

TABLE 4-3a

OCS PRODUCTION FROM 1986 AND LATER SOURCES
($32/bbl of oil - 1986 dollars)

	OIL PRODUCTION (BARRELS PER DAY)			GAS PRODUCTION (TCF/YEAR)		
YEAR	TOTAL[a]	PRE-1986 SOURCES[b]	1986 AND LATER SOURCES[c]	TOTAL[a]	PRE-1986 SOURCES[b]	1986 AND LATER SOURCES[c]
1990	1,178,000	491,000	687,000	3.5	2.48	1.02
1993	1,315,000	298,000	1,017,000	3.77	1.52	2.25
1995	1,458,000	214,000	1,244,000	3.84	1.1	2.74
2000	1,672,000	94,000	1,578,000	3.96	0.49	3.47

Source: ERG estimates.

[a]MMS projections, see Table 4-1.

[b]See Table 4-2.

[c]Total production minus pre-1986 production.

TABLE 4-3b

OCS PRODUCTION FROM 1986 AND LATER SOURCES
($21/bbl of oil - 1986 dollars)

	OIL PRODUCTION (BARRELS PER DAY)			GAS PRODUCTION (TCF/YEAR)		
YEAR	TOTAL[a]	PRE-1986 SOURCES[b]	1986 AND LATER SOURCES[c]	TOTAL[a]	PRE-1986 SOURCES[b]	1986 AND LATER SOURCES[c]
1990	1,074,000	472,000	602,000	3.35	2.39	0.96
1993	1,167,000	287,000	880,000	3.42	1.47	1.95
1995	1,224,000	207,000	1,017,000	3.47	1.06	2.41
2000	1,197,000	91,000	1,106,000	3.47	0.47	3.00

Source: ERG estimates.

[a]MMS projections, see Table 4-1.

[b]See Table 4-2.

[c]Total production minus pre-1986 production.

TABLE 4-3c

OCS PRODUCTION FROM 1986 AND LATER SOURCES
($15/bbl of oil - 1986 dollars)

	OIL PRODUCTION (BARRELS PER DAY)			GAS PRODUCTION (TCF/YEAR)		
YEAR	TOTAL[a]	PRE-1986 SOURCES[b]	1986 AND LATER SOURCES[c]	TOTAL[a]	PRE-1986 SOURCES[b]	1986 AND LATER SOURCES[c]
1990	898,000	418,000	480,000	2.96	2.13	0.83
1993	961,000	255,000	706,000	2.94	1.3	1.64
1995	1,005,000	184,000	821,000	2.99	0.94	2.05
2000	965,000	81,000	884,000	3.00	0.42	2.58

Source: ERG estimates.

[a]MMS projections, see Table 4-1.

[b]See Table 4-2.

[c]Total production minus pre-1986 production.

TABLE 4-4a

1986 AND LATER NSPS PRODUCTION
($32/bbl of oil - 1986 dollars)

	OIL PRODUCTION (BARRELS PER DAY)				GAS PRODUCTION (TCF/YEAR)			
REGION	1990	1993	1995	2000	1990	1993	1995	2000
Gulf of Mexico	342,000	541,000	669,000	783,000	0.89	2.12	2.71	2.33
Pacific	345,000	408,000	424,000	370,000	0.13	0.21	0.24	0.31
Atlantic	0	68,000	55,000	41,000	0	0.41	0.31	0.24
Alaska	0	0	96,000	384,000	0	0	0.07	0.21
Total	687,000	1,017,000	1,244,000	1,578,000	1.02	2.74	3.47	2.58

Source: ERG estimates developed using Table 4-1 and Table 4-2.

TABLE 4-4b

1986 AND LATER NSPS PRODUCTION
($21/bbl of oil - 1986 dollars)

	OIL PRODUCTION (BARRELS PER DAY)				GAS PRODUCTION (TCF/YEAR)			
REGION	1990	1993	1995	2000	1990	1993	1995	2000
Gulf of Mexico	330,000	522,000	645,000	755,000	0.86	1.57	2.05	2.62
Pacific	272,000	323,000	335,000	292,000	0.10	0.17	0.19	0.24
Atlantic	0	35,000	28,000	21,000	0	0.21	0.16	0.12
Alaska	0	0	0	0	0	0	0.01	0.02
Total	602,000	880,000	1,017,000	1,106,000	0.96	1.95	2.41	3.00

Source: ERG estimates developed using Table 4-1 and Table 4-2.

TABLE 4-4c

1986 AND LATER NSPS PRODUCTION
($15/bbl of oil - 1986 dollars)

	OIL PRODUCTION (BARRELS PER DAY)				GAS PRODUCTION (TCF/YEAR)			
REGION	1990	1993	1995	2000	1990	1993	1995	2000
Gulf of Mexico	293,000	464,000	574,000	671,000	0.76	1.40	1.82	2.33
Pacific	187,000	220,000	229,000	200,000	0.07	0.11	0.13	0.17
Atlantic	0	22,000	18,000	13,000	0	0.13	0.10	0.08
Alaska	0	0	0	0	0	0	0	0
Total	480,000	706,000	821,000	884,000	0.83	1.64	2.05	2.58

Source: ERG estimates developed using Table 4-1 and Table 4-2.

4.2.1 Productive Wells

Federal OCS Well Projections

Once 1986 and later production levels are established, the number of wells likely to be installed to account for this production can be estimated. ERG estimated new wells for each region using the initial rates of production, years at peak production, and decline rates shown above. Tables 4-5a, b, and c show total new OCS development wells for 1986-2000. At $32 per barrel, OCS development wells for 1986-2000 total 8,588, of which 5,173 are oil wells. At $21 per barrel, well projections total 7,601; at $15 per barrel, they total 6,384. The majority (70 to 80 percent) of the wells are located in the Gulf of Mexico.

State Water Well Projections

State water activity in Alaska between 1980 and 1985 was quantified relative to OCS activity in that region. During that period, the ratio of State-to-Federal oil development was found to be 3:1 for Alaska. For the Pacific region, Table 2-11 lists 1,656 wells on State leases and 341 wells on Federal leases. The State well counts, however, include Huntington, Wilmington, and Belmont fields which may be considered coastal rather than offshore (i.e., they are beyond the natural coastline but may not be seaward of the inner boundary of the territorial seas). Not including the wells from these fields results in 225 wells on State leases, or about two-thirds of the number of wells on Federal leases. Since future activity may be less due to the extensive exploration already performed in State waters, an estimated State-to-Federal ratio of 1:2 is used for the Pacific.[3] The 1:2 and 3:1 ratios for the Pacific and Alaska, respectively, are assumed to be valid for the 1986-2000 period. Since no Atlantic State water activity is expected to occur in the projected future, this region was not included in State waters' projections.

In the Gulf, the State-to-Federal ratio is based on data from 1967 to 1985. American Petroleum Institute (API) data for all offshore wells were used to obtain total well counts, while MMS data were used for well counts in

[3]In light of the recent moratorium on activity in California State waters (Meier, 1990) this assumption may create an overestimate of the number of projected wells and thus an overestimate of the regulatory costs. This issue is addressed under the restricted activity scenario explained in Section 4.4.

TABLE 4-5a

FEDERAL OCS WELL PROJECTIONS BY REGION, 1986-2000
($32/bbl of oil - 1986 dollars)

REGION	OIL WELLS	GAS WELLS	TOTAL WELLS
Gulf	3,213	2,912	6,125
Pacific	1,617	302	1,919
Atlantic	109	165	274
Alaska	234	36	270
Total Federal Waters	5,173	3,415	8,588

Source: ERG estimates.

TABLE 4-5b

FEDERAL OCS WELL PROJECTIONS BY REGION, 1986-2000
($21/bbl of oil - 1986 dollars)

REGION	OIL WELLS	GAS WELLS	TOTAL WELLS
Gulf	3,103	2,812	5,915
Pacific	1,277	239	1,516
Atlantic	56	85	141
Alaska	23	6	29
Total Federal Waters	4,459	3,142	7,601

Source: ERG estimates.

TABLE 4-5c

FEDERAL OCS WELL PROJECTIONS BY REGION, 1986-2000
($15/bbl of oil - 1986 dollars)

REGION	OIL WELLS	GAS WELLS	TOTAL WELLS
Gulf	2,757	2,501	5,258
Pacific	874	162	1,036
Atlantic	36	54	90
Alaska	0	0	0
Total Federal Waters	3,667	2,717	6,384

Source: ERG estimates.

Federal waters. State well counts were estimated as the difference between total offshore activity and Federal activity. During this period, the State-to-Federal ratio dropped approximately 30 percent every 7 years. Based on this data, the Gulf ratios for oil and gas were calculated as follows: 11 percent for 1986-1992, 8 percent for 1993-2000, 6 percent for 2001-2008, and 4 percent for 2009-2015. Only in the Gulf will State water gas activity be significant.

Table 4-6 presents estimates of State water wells for 1986-2000. In the $32 scenario, a total of 2,075 State water wells are projected. Oil wells in that scenario total 1,810. In the $21 and $15 scenarios, State water wells total 1,250 and 920 wells, respectively.

Inasmuch as the API offshore well counts include coastal as well as offshore wells, projected activity in State waters in the Gulf of Mexico may be overestimated. The number of projected wells, however, does not affect the per-well costs (see Section Five) used in the economic impact analysis of model projects (discussed in Section Six). If no or minimal impacts are seen on representative projects or companies that bear these costs (Section Seven), then the inclusion of coastal wells in projected State water activity does not affect the conclusions drawn from the analysis.

The inclusion of some coastal wells may, however, lead to overestimation of total annual regulatory costs. State water activity in the Gulf ranges from 5.3 to 6.7 percent of all activity under the various scenarios (see Tables 4-5 and 4-6). Even if all future activity in State waters in the Gulf occurs in the coastal regions, the total projections would decrease by no more than 6.7 percent. While more precise estimates are not available at the time of this report, any revisions in State activity estimates are not expected to decrease by more than this.

4.2.2 Unproductive Drilling Efforts

The API Basic Petroleum Data Book (API, 1988, Section XI, Table 7a) lists an all-time total of 29,954 offshore wells drilled in Federal and State waters as of January 1, 1985. Of these, 12,049 were dry holes; therefore, the discovery efficiency was 60 percent. This value was used to forecast the number of dry holes in our projections. At $32 per barrel, dry well

TABLE 4-6a

WELL PROJECTIONS IN STATE WATERS BY REGION, 1986-2000
($32/bbl of oil - 1986 dollars)

REGION	OIL WELLS	GAS WELLS	TOTAL WELLS
Gulf State Waters (Texas, Louisiana, Mississippi, Alabama)	297	265	562
Pacific State Waters	811	0	811
Atlantic State Waters	0	0	0
Alaska State Waters	702	0	702
Total State Waters	1,810	265	2,075

Source: ERG estimates based on the historic ratio of Federal-to-State water activity.

TABLE 4-6b

WELL PROJECTIONS IN STATE WATERS BY REGION, 1986-2000
($21/bbl of oil - 1986 dollars)

REGION	OIL WELLS	GAS WELLS	TOTAL WELLS
Gulf State Waters (Texas, Louisiana, Mississippi, Alabama)	283	255	538
Pacific State Waters	643	0	643
Atlantic State Waters	0	0	0
Alaska State Waters	69	0	69
Total State Waters	955	255	1,250

Source: ERG estimates based on the historic ratio of Federal-to-State water activity.

TABLE 4-6c

WELL PROJECTIONS IN STATE WATERS BY REGION, 1986-2000
($15/bbl of oil - 1986 dollars)

REGION	OIL WELLS	GAS WELLS	TOTAL WELLS
Gulf State Waters (Texas, Louisiana, Mississippi, Alabama)	253	227	480
Pacific State Waters	440	0	440
Atlantic State Waters	0	0	0
Alaska State Waters	0	0	0
Total State Waters	693	227	920

Source: ERG estimates based on the historic ratio of Federal-to-State water activity.

projections total 7,005. Dry well projections for the $21 per barrel and $15 per barrel scenarios are 5,820 and 4,800 wells, respectively, and represent unrestricted development for these oil prime scenarios. See Section 4.4 for a discussion of the restricted development scenario.

4.2.3 Total Well Projections

Table 4-7 presents total productive development wells by region, by combining the data shown in Tables 4-5 and 4-6. At $32 per barrel, productive wells total 10,663. For the $21 and $15 forecasts, productive wells total 8,851 and 7,304, respectively.

Combining productive and dry wells, ERG obtains 17,668 wells drilled for the $32/bbl scenario, 14,671 wells drilled for the $21/bbl scenario, and 12,104 wells drilled for the $15/bbl scenario. Table 4-8 presents the average number of total wells drilled per year during the 15-year period. These figures are 1,178, 978, and 807 for the $32/bbl, $21/bbl, and $15/bbl scenarios, respectively, and represent unrestricted development for these oil price scenarios. See Section 4.4 for a discussion of the restricted development scenario.

4.3 PLATFORM PROJECTIONS, 1986-2000 - UNRESTRICTED DEVELOPMENT

4.3.1 Total Platforms

To convert projections of well drilling in each region into projections of platform installations, ERG used selected model project sizes. Table 4-9 summarizes the methodology for allocating wells to platforms. Platform sizes vary from single well structures in the Gulf platforms to 48 well slots on Alaskan gravel islands. Six different platform sizes were modeled in the Gulf, two in the Pacific, three in Alaska, and one in the Atlantic region. The distribution of platforms was based upon platform configuration data provided in a previous report (EPA, 1985), 1988 platform configurations in the Gulf, and the well projections discussed above.

The unrestricted platform projections for the four regions are shown in Tables 4-10 and 4-11. For 1986-2000, the total number of platforms is expected to be 931 under the $32 scenario (Table 4-10). Of these, 778

TABLE 4-7a

FEDERAL AND STATE POST-NSPS OFFSHORE WELLS, 1986-2000
($32/bbl of oil - 1986 dollars)

REGION	OIL WELLS	GAS WELLS	TOTAL WELLS
Gulf			
State	297	265	562
OCS	3,213	2,912	6,125
Pacific			
State	811	0	811
OCS	1,617	302	1,919
Atlantic			
State	0	0	0
OCS	109	165	274
Alaska			
State	702	0	702
OCS	234	36	270
Total	6,983	3,680	10,663

Source: ERG estimates; see Tables 4-5a and 4-6a.

TABLE 4-7b

FEDERAL AND STATE POST-NSPS OFFSHORE WELLS, 1986-2000
($21/bbl of oil - 1986 dollars)

REGION	OIL WELLS	GAS WELLS	TOTAL WELLS
Gulf			
State	283	255	538
OCS	3,103	2,812	5,915
Pacific			
State	643	0	643
OCS	1,277	239	1,516
Atlantic			
State	0	0	0
OCS	56	85	141
Alaska			
State	69	0	69
OCS	23	6	29
Total	5,454	3,397	8,851

Source: ERG estimates; see Tables 4-5b and 4-6b.

TABLE 4-7c

FEDERAL AND STATE POST-NSPS OFFSHORE WELLS, 1986-2000
($15/bbl of oil - 1986 dollars)

REGION	OIL WELLS	GAS WELLS	TOTAL WELLS
Gulf			
State	253	227	480
OCS	2,757	2,501	5,258
Pacific			
State	440	0	440
OCS	874	162	1,036
Atlantic			
State	0	0	0
OCS	36	54	90
Alaska			
State	0	0	0
OCS	0	0	0
Total	4,360	2,944	7,304

Source: ERG estimates; see Tables 4-5c and 4-6c.

TABLE 4-8

TOTAL OFFSHORE PRODUCING WELLS AND DRY HOLES - AVERAGE NUMBER OF WELLS PER YEAR

UNRESTRICTED DEVELOPMENT

PRICE ASSUMPTION $/BARREL*	AVERAGE NO. OF PRODUCING WELLS PER YEAR	AVERAGE NO. OF DRY HOLES PER YEAR	AVERAGE NO. OF TOTAL WELLS PER YEAR
$15	487	320	807
$21	590	388	978
$32	711	467	1,178

*1986 dollars.

Source: ERG estimates based upon pre-1986 production levels in the MMS forecast.

TABLE 4-9

PLATFORM CONFIGURATION SUMMARY

UNRESTRICTED ACTIVITY

REGION	WELL SLOTS	ACTIVE WELLS	PERCENT ALLOCATION OF REGIONAL PLATFORMS				PERCENT ALLOCATION OF REGIONAL WELLS			
			FEDERAL WATERS		STATE WATERS		FEDERAL WATERS		STATE WATERS	
			OIL	GAS	OIL	GAS	OIL	GAS	OIL	GAS
GULF	1	1	5%	15%	5%	15%	0.4%	2%	1%	3%
	4	4	32%	35%	32%	53%	9%	18%	19%	31%
	6	6	8%	17%	38%	50%	4%	13%	35%	66%
	12	10	25%	22%	25%	0%	22%	34%	45%	0%
	24	18	20%	11%	0%	0%	35%	34%	0%	0%
	40	32	10%	0%	0%	0%	29%	0%	0%	0%
Pacific	16	14	30%	100%	0%	0%	15%	100%	0%	0%
	40	32	70%	0%	100%	0%	85%	0%	100%	0%
Alaska	24	18	15%	0%	0%	0%	15%	0%	0%	0%
	12	10	0%	100%	0%	0%	0%	100%	0%	0%
	48(a)	40	85%	0%	100%	0%	85%	0%	100%	0%
Atlantic	24	18	100%	100%	0%	0%	100%	100%	0%	0%

(a) For platforms within 4 miles, a gravel island was utilized.

Source: ERG estimates based on MMS data.

TABLE 4-10
($32/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - TOTAL
UNRESTRICTED ACTIVITY

ALL PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		16 WELLS	40 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	62	0	0	0		6	18	9	12	9	2		3	3		0	
1987	64	0	0	0		6	19	10	13	10	3		1	2		0	
1988	14	0	0	0		0	2	1	2	1	1		3	4		0	
1989	35	0	0	0		2	9	5	7	5	1		1	5		0	
1990	48	0	0	0		4	11	7	9	5	1		4	7		0	
1991	54	0	0	0		5	15	8	11	7	2		2	4		0	
1992	76	0	0	0		7	19	10	14	9	2		2	5		8	
1993	73	0	0	0		6	18	10	15	9	3		3	5		4	
1994	78	0	1	2		7	22	11	16	10	2		2	5		0	
1995	71	0	0	3		5	18	10	14	9	2		4	6		0	
1996	72	0	1	3		7	19	10	15	10	2		2	3		0	
1997	76	0	0	4		6	18	10	14	9	2		3	8		2	
1998	73	0	1	3		7	20	9	14	9	2		3	4		1	
1999	67	0	0	3		6	17	9	14	8	2		4	4		0	
2000	68	2	1	6		6	16	8	13	8	2		3	3		0	
2001	50	0	0	2		4	13	6	10	7	2		1	4		1	
2002	59	0	0	4		4	14	7	11	7	2		1	4		5	
2003	53	0	0	2		5	12	6	9	6	1		3	4		5	
2004	53	0	0	3		4	14	7	11	6	2		2	2		2	
2005	40	0	0	3		3	11	5	8	5	1		2	2		0	
2006	38	0	1	0		3	11	5	8	5	1		2	2		0	
2007	33	0	0	2		2	8	3	7	4	1		1	3		2	
2008	34	0	0	2		2	9	4	5	4	1		2	2		3	
2009	29	0	0	0		2	8	4	7	4	1		1	2		0	
2010	13	0	0	1		1	4	2	2	1	0		1	1		0	
2011	24	0	1	1		1	5	3	5	3	1		1	2		1	
2012	17	0	0	2		1	3	1	3	2	0		1	2		2	
2013	11	0	0	0		0	2	0	2	2	1		1	1		2	
2014	12	0	0	0		1	2	1	2	1	0		1	2		2	
2015	11	0	1	0		1	3	2	2	2	0		0	0		0	
1985-2015	1408	2	7	46	55	114	360	183	275	177	43	1152	60	101	161	40	40
1985-2000	931	2	4	24	30	80	241	127	183	118	29	778	40	68	108	15	15

TABLE 4-11
($21/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - TOTAL
UNRESTRICTED ACTIVITY

ALL PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		16 WELLS	40 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	57	0	0	0		6	17	8	12	8	2		2	2		0	
1987	64	0	0	0		6	18	10	15	9	2		1	3		0	
1988	16	0	0	0		0	3	2	3	2	1		2	3		0	
1989	32	0	0	0		2	9	5	7	4	1		1	3		0	
1990	39	0	0	0		2	11	6	7	5	1		2	5		0	
1991	54	0	0	0		5	15	8	11	6	2		3	4		0	
1992	71	0	0	0		7	19	10	14	9	2		1	4		5	
1993	67	0	0	0		6	18	9	15	9	2		3	4		1	
1994	74	0	0	0		7	21	12	16	10	2		2	4		0	
1995	61	0	0	0		5	17	8	14	9	2		2	4		0	
1996	66	0	0	1		6	19	9	14	9	2		2	4		0	
1997	68	0	0	0		6	18	10	14	9	2		2	5		2	
1998	65	0	1	0		6	17	9	14	9	2		3	4		0	
1999	60	0	0	0		6	17	9	12	8	2		3	3		0	
2000	57	1	0	1		6	16	8	12	8	2		1	2		0	
2001	42	0	0	0		4	12	5	9	6	2		1	3		0	
2002	53	0	0	0		4	14	7	11	7	2		1	4		3	
2003	47	0	0	0		4	12	6	9	6	1		3	3		3	
2004	44	0	0	1		4	13	6	10	6	2		1	1		0	
2005	36	0	0	0		3	11	5	7	5	1		2	2		0	
2006	32	0	0	0		3	8	5	7	5	1		1	2		0	
2007	32	0	0	0		2	8	5	6	4	1		1	3		2	
2008	28	0	0	1		2	7	5	5	4	1		1	1		1	
2009	23	0	0	0		2	6	3	5	4	1		1	0		1	
2010	12	0	0	0		1	3	2	2	1	0		1	2		0	
2011	22	0	0	0		1	6	3	5	3	1		1	2		0	
2012	13	0	0	0		1	3	2	3	2	0		0	1		1	
2013	7	0	0	0		0	2	0	1	1	1		0	2		0	
2014	13	0	0	0		1	3	1	2	2	0		1	1		2	
2015	7	0	0	0		1	2	1	2	1	0		0	0		0	
1985-2015	1262	1	1	4	6	109	345	179	264	171	41	1109	45	81	126	21	21
1985-2000	851	1	1	2	4	76	235	123	180	114	27	755	30	54	84	8	8

platforms are located in the Gulf. This projection represents the high end of the projections and thus would create the highest cost scenario. For the $21 scenario, the total number of platforms is projected to be 851 (see Table 4-11).

4.3.2 Platforms in 4-Mile Category

Certain regulatory options require different pollution controls depending on whether the platform is within 4 miles of shore. It is, therefore, necessary to subcategorize the platforms according to their distance from shore. The 4-mile category includes all activity in State waters plus platforms that may occur in the 1-mile band in Federal waters between 3 and 4 miles from shore.[4] For the Gulf, the MMS data base was used to determine the percentages of wells and structures that occur in the 1-mile band in Federal waters between 3 and 4 miles from shore. The percentages were done on a model basis:

Gulf 1b	20.9%[5]
Gulf 4	12.7%
Gulf 6	1.4%
Gulf 12	0.7%
Gulf 24	2.7%
Gulf 40	0.0%

See Kaplan 1990.

For Alaska and the Pacific, only platforms in State waters are considered. This is not to presume that no activity will occur in that 1-mile band in Federal waters that adjoin State waters. In the platform projections, wells

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[4]The offshore authority of Texas and Florida (on its Gulf Coast side only) extends to 3 marine leagues (about 10.35 statute miles) for historical reasons. Within these areas, all offshore activity within 4 miles of shore would be in State waters. The well and platform projections for State water activity in the Gulf of Mexico are not subcategorized by State. No attempt has been made to subtract projected activity that may occur between the 4 mile and 3 league lines in Texas and Florida. As mentioned earlier in this section, State water activity in the Gulf ranges from 5.3 to 6.3 percent of all projected activity (see Tables 4-5 and 4-6). Historically, most development has been off Louisiana (see Table 2-10). The approach taken in this analysis, then, would lead to only a small overestimate of regulatory costs.

[5]This is not to say that no single well structures without production equipment will be set in the Gulf. Since four Gulf 1a structures are assumed to share production equipment, they have been included in the Gulf 4 projections since the per-project impacts are so similar. This approach does not change the total estimated cost of an option.

are allocated to whole platforms only (i.e., there are no fractional platforms in the projections). Two gravel islands are included in the projections for Alaska State waters for the $21/bbl scenario, which more than accounts for the wells projected in Table 4-6. These islands remain as shallow water, or within 4 miles, structures under this definition.

In the Pacific, the number of projected wells in State waters is derived by estimating activity in State waters as a percentage of activity in Federal waters. As mentioned in Section 4.2.1, this estimate may be high in light of the current moratorium on activity in California waters. The amount of estimated activity in State waters is sufficiently high to address any activity that might occur in the 1-mile band adjacent to the Federal/State boundary.

Tables 4-12 and 4-13 present the distribution of projected platforms based on the 4-mile cutoff under the $32 and $21 scenarios, respectively. Tables 4-14 and 4-15 show the oil-producing platform projections under the $32 and $21 scenarios, respectively.

4.4 PLATFORM PROJECTIONS, 1986-2000 - RESTRICTED DEVELOPMENT

4.4.1 Total Platforms

The number of platforms projected in Section 4.3.1 assumes that all oil and gas development which is economically feasible will take place. In this section these projections have been adjusted for the Pacific and Atlantic regions to account for recent governmental decisions.

<u>California State Waters</u>

A combination of State legislation and declarations by the California State Lands Commission has essentially banned further leasing of California State waters from development for oil and gas. Under article 4, Section 6871 of the California Public Resources Code, discretion over whether to lease submerged lands for oil and gas development is given to the State Lands

TABLE 4-12
($32/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - WITHIN 4-MILES
UNRESTRICTED ACTIVITY

ALL PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	GRAVEL ISLAND		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		16 WELLS	40 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	13	0	0	0		2	5	4	1	0	0		0	1		0	
1987	14	0	0	0		2	6	4	1	0	0		0	1		0	
1988	2	0	0	0		0	0	1	0	0	0		0	1		0	
1989	8	0	0	0		0	3	2	1	0	0		0	2		0	
1990	12	0	0	0		2	3	3	1	0	0		0	3		0	
1991	12	0	0	0		2	5	3	1	0	0		0	1		0	
1992	14	0	0	0		2	5	4	1	0	0		0	2		0	
1993	12	0	0	0		2	4	3	1	0	0		0	2		0	
1994	16	0	0	2		2	5	4	1	0	0		0	2		0	
1995	13	0	0	2		1	4	3	1	0	0		0	2		0	
1996	13	0	0	2		2	4	3	1	0	0		0	1		0	
1997	16	0	0	3		2	4	3	1	0	0		0	3		0	
1998	15	0	0	2		2	5	3	1	0	0		0	2		0	
1999	14	0	0	3		2	4	3	1	0	0		0	1		0	
2000	15	0	0	4		2	4	3	1	0	0		0	1		0	
2001	9	0	0	2		1	3	1	0	0	0		0	2		0	
2002	12	0	0	3		1	4	2	1	0	0		0	1		0	
2003	8	0	0	2		1	2	1	0	0	0		0	2		0	
2004	11	0	0	2		1	4	2	1	0	0		0	1		0	
2005	6	0	0	2		1	2	1	0	0	0		0	0		0	
2006	8	0	0	0		1	3	2	1	0	0		0	1		0	
2007	4	0	0	2		0	1	0	0	0	0		0	1		0	
2008	5	0	0	1		0	2	1	0	0	0		0	1		0	
2009	5	0	0	0		0	2	1	1	0	0		0	1		0	
2010	3	0	0	1		0	1	1	0	0	0		0	0		0	
2011	3	0	0	1		0	1	0	0	0	0		0	1		0	
2012	2	0	0	1		0	0	0	0	0	0		0	1		0	
2013	0	0	0	0		0	0	0	0	0	0		0	0		0	
2014	1	0	0	0		0	0	0	0	0	0		0	1		0	
2015	1	0	0	0		0	0	1	0	0	0		0	0		0	
1985-2015	267	0	0	35	35	31	86	59	18	0	0	194	0	38	38	0	0
1985-2000	189	0	0	18	18	25	61	46	14	0	0	146	0	25	25	0	0

TABLE 4-12 (Cont.)
($32/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - BEYOND 4-MILES
UNRESTRICTED ACTIVITY

ALL PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		16 WELLS	40 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	49	0	0	0		4	13	5	11	9	2		3	2		0	
1987	50	0	0	0		4	13	6	12	10	3		1	1		0	
1988	12	0	0	0		0	2	0	2	1	1		3	3		0	
1989	27	0	0	0		2	6	3	6	5	1		1	3		0	
1990	36	0	0	0		2	8	4	8	5	1		4	4		0	
1991	42	0	0	0		3	10	5	10	7	2		2	3		0	
1992	62	0	0	0		5	14	6	13	9	2		2	3		8	
1993	61	0	0	0		4	14	7	14	9	3		3	3		4	
1994	62	0	1	0		5	17	7	15	10	2		2	3		0	
1995	58	0	0	1		4	14	7	13	9	2		4	4		0	
1996	59	0	1	1		5	15	7	14	10	2		2	2		0	
1997	60	0	0	1		4	14	7	13	9	2		3	5		2	
1998	58	0	1	1		5	15	6	13	9	2		3	2		1	
1999	53	0	0	0		4	13	6	13	8	2		4	3		0	
2000	53	2	1	2		4	12	5	12	8	2		3	2		0	
2001	41	0	0	0		3	10	5	10	7	2		1	2		1	
2002	47	0	0	1		3	10	5	10	7	2		1	3		5	
2003	45	0	0	0		4	10	5	9	6	1		3	2		5	
2004	42	0	0	1		3	10	5	10	6	2		2	1		2	
2005	34	0	0	1		2	9	4	8	5	1		2	2		0	
2006	30	0	1	0		2	8	3	7	5	1		2	1		0	
2007	29	0	0	0		2	7	3	7	4	1		1	2		2	
2008	29	0	0	1		2	7	3	5	4	1		2	1		3	
2009	24	0	0	0		2	6	3	6	4	1		1	1		0	
2010	10	0	0	0		1	3	1	2	1	0		1	1		0	
2011	21	0	1	0		1	4	3	5	3	1		1	1		1	
2012	15	0	0	1		1	3	1	3	2	0		1	1		2	
2013	11	0	0	0		0	2	0	2	2	1		1	1		2	
2014	11	0	0	0		1	2	1	2	1	0		1	1		2	
2015	10	0	1	0		1	3	1	2	2	0		0	0		0	
1985-2015	1141	2	7	11	20	83	274	124	257	177	43	958	60	63	123	40	40
1985-2000	742	2	4	6	12	55	180	81	169	118	29	632	40	43	83	15	15

TABLE 4-13
($21/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - WITHIN 4-MILES
UNRESTRICTED ACTIVITY

ALL PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		16 WELLS	40 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	12	0	0	0		2	5	3	1	0	0		0	1		0	
1987	14	0	0	0		2	5	4	2	0	0		0	1		0	
1988	2	0	0	0		0	0	1	0	0	0		0	1		0	
1989	7	0	0	0		0	3	2	1	0	0		0	1		0	
1990	7	0	0	0		0	3	2	0	0	0		0	2		0	
1991	12	0	0	0		2	5	3	1	0	0		0	1		0	
1992	14	0	0	0		2	5	4	1	0	0		0	2		0	
1993	11	0	0	0		2	4	3	1	0	0		0	1		0	
1994	14	0	0	0		2	5	4	1	0	0		0	2		0	
1995	9	0	0	0		1	4	2	1	0	0		0	1		0	
1996	14	0	0	1		2	5	3	1	0	0		0	2		0	
1997	12	0	0	0		2	4	3	1	0	0		0	2		0	
1998	11	0	0	0		2	4	3	1	0	0		0	1		0	
1999	11	0	0	0		2	4	3	1	0	0		0	1		0	
2000	12	0	0	1		2	4	3	1	0	0		0	1		0	
2001	5	0	0	0		1	2	1	0	0	0		0	1		0	
2002	10	0	0	0		1	4	2	1	0	0		0	2		0	
2003	5	0	0	0		1	2	1	0	0	0		0	1		0	
2004	8	0	0	1		1	3	2	1	0	0		0	0		0	
2005	5	0	0	0		1	2	1	0	0	0		0	1		0	
2006	5	0	0	0		1	1	2	0	0	0		0	1		0	
2007	4	0	0	0		0	1	2	0	0	0		0	1		0	
2008	3	0	0	0		0	1	2	0	0	0		0	0		0	
2009	1	0	0	0		0	1	0	0	0	0		0	0		0	
2010	2	0	0	0		0	0	1	0	0	0		0	1		0	
2011	4	0	0	0		0	2	1	0	0	0		0	1		0	
2012	1	0	0	0		0	0	1	0	0	0		0	0		0	
2013	1	0	0	0		0	0	0	0	0	0		0	1		0	
2014	0	0	0	0		0	0	0	0	0	0		0	0		0	
2015	0	0	0	0		0	0	0	0	0	0		0	0		0	
1985-2015	216	0	0	3	3	29	79	59	16	0	0	183	0	30	30	0	0
1985-2000	162	0	0	2	2	23	60	43	14	0	0	140	0	20	20	0	0

TABLE 4-13 (Cont.)
($21/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS- BEYOND 4-MILES
UNRESTRICTED ACTIVITY

ALL PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		16 WELLS	40 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	45	0	0	0		4	12	5	11	8	2		2	1		0	
1987	50	0	0	0		4	13	6	13	9	2		1	2		0	
1988	14	0	0	0		0	3	1	3	2	1		2	2		0	
1989	25	0	0	0		2	6	3	6	4	1		1	2		0	
1990	32	0	0	0		2	8	4	7	5	1		2	3		0	
1991	42	0	0	0		3	10	5	10	6	2		3	3		0	
1992	57	0	0	0		5	14	6	13	9	2		1	2		5	
1993	56	0	0	0		4	14	6	14	9	2		3	3		1	
1994	60	0	0	0		5	16	8	15	10	2		2	2		0	
1995	52	0	0	0		4	13	6	13	9	2		2	3		0	
1996	52	0	0	0		4	14	6	13	9	2		2	2		0	
1997	56	0	0	0		4	14	7	13	9	2		2	3		2	
1998	54	0	1	0		4	13	6	13	9	2		3	3		0	
1999	49	0	0	0		4	13	6	11	8	2		3	2		0	
2000	45	1	0	0		4	12	5	11	8	2		1	1		0	
2001	37	0	0	0		3	10	4	9	6	2		1	2		0	
2002	43	0	0	0		3	10	5	10	7	2		1	2		3	
2003	42	0	0	0		3	10	5	9	6	1		3	2		3	
2004	36	0	0	0		3	10	4	9	6	2		1	1		0	
2005	31	0	0	0		2	9	4	7	5	1		2	1		0	
2006	27	0	0	0		2	7	3	7	5	1		1	1		0	
2007	28	0	0	0		2	7	3	6	4	1		1	2		2	
2008	25	0	0	1		2	6	3	5	4	1		1	1		1	
2009	22	0	0	0		2	5	3	5	4	1		1	0		1	
2010	10	0	0	0		1	3	1	2	1	0		1	1		0	
2011	18	0	0	0		1	4	2	5	3	1		1	1		0	
2012	12	0	0	0		1	3	1	3	2	0		0	1		1	
2013	6	0	0	0		0	2	0	1	1	1		0	1		0	
2014	13	0	0	0		1	3	1	2	2	0		1	1		2	
2015	7	0	0	0		1	2	1	2	1	0		0	0		0	
1985-2015	1046	1	1	1	3	80	266	120	248	171	41	926	45	51	96	21	21
1985-2000	689	1	1	0	2	53	175	80	166	114	27	615	30	34	64	8	8

TABLE 4-14
($32/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - WITHIN 4-MILES
UNRESTRICTED ACTIVITY

OIL PRODUCING PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		16 WELLS	40 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	6	0	0	0		0	2	2	1	0	0		0	1		0	
1987	7	0	0	0		0	3	2	1	0	0		0	1		0	
1988	2	0	0	0		0	0	1	0	0	0		0	1		0	
1989	5	0	0	0		0	1	1	1	0	0		0	2		0	
1990	6	0	0	0		0	1	1	1	0	0		0	3		0	
1991	5	0	0	0		0	2	1	1	0	0		0	1		0	
1992	6	0	0	0		0	2	1	1	0	0		0	2		0	
1993	6	0	0	0		0	2	1	1	0	0		0	2		0	
1994	8	0	0	2		0	2	1	1	0	0		0	2		0	
1995	8	0	0	2		0	2	1	1	0	0		0	2		0	
1996	7	0	0	2		0	2	1	1	0	0		0	1		0	
1997	10	0	0	3		0	2	1	1	0	0		0	3		0	
1998	8	0	0	2		0	2	1	1	0	0		0	2		0	
1999	8	0	0	3		0	2	1	1	0	0		0	1		0	
2000	9	0	0	4		0	2	1	1	0	0		0	1		0	
2001	5	0	0	2		0	1	0	0	0	0		0	2		0	
2002	8	0	0	3		0	2	1	1	0	0		0	1		0	
2003	4	0	0	2		0	0	0	0	0	0		0	2		0	
2004	7	0	0	2		0	2	1	1	0	0		0	1		0	
2005	2	0	0	2		0	0	0	0	0	0		0	0		0	
2006	5	0	0	0		0	2	1	1	0	0		0	1		0	
2007	3	0	0	2		0	0	0	0	0	0		0	1		0	
2008	2	0	0	1		0	0	0	0	0	0		0	1		0	
2009	4	0	0	0		0	1	1	1	0	0		0	1		0	
2010	1	0	0	1		0	0	0	0	0	0		0	0		0	
2011	2	0	0	1		0	0	0	0	0	0		0	1		0	
2012	2	0	0	1		0	0	0	0	0	0		0	1		0	
2013	0	0	0	0		0	0	0	0	0	0		0	0		0	
2014	1	0	0	0		0	0	0	0	0	0		0	1		0	
2015	0	0	0	0		0	0	0	0	0	0		0	0		0	
1985-2015	147	0	0	35	35	0	35	21	18	0	0	74	0	38	38	0	0
1985-2000	101	0	0	18	18	0	27	17	14	0	0	58	0	25	25	0	0

TABLE 4-14 (Cont.)
($32/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - BEYOND 4-MILES
UNRESTRICTED ACTIVITY

OIL PRODUCING PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		16 WELLS	40 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	22	0	0	0		1	5	1	5	5	2		1	2		0	
1987	26	0	0	0		1	6	2	6	6	3		1	1		0	
1988	8	0	0	0		0	1	0	1	1	1		1	3		0	
1989	15	0	0	0		0	3	1	3	3	1		1	3		0	
1990	16	0	0	0		0	3	1	3	2	1		2	4		0	
1991	19	0	0	0		1	3	1	4	4	2		1	3		0	
1992	24	0	0	0		1	4	1	5	4	2		1	3		3	
1993	27	0	0	0		1	5	2	6	5	3		1	3		1	
1994	24	0	0	0		1	5	1	6	5	2		1	3		0	
1995	28	0	0	1		1	5	2	6	5	2		2	4		0	
1996	25	0	0	1		1	5	2	6	5	2		1	2		0	
1997	30	0	0	1		1	5	2	6	5	2		2	5		1	
1998	24	0	0	1		1	5	1	5	5	2		1	2		1	
1999	21	0	0	0		1	4	1	5	4	2		1	3		0	
2000	24	2	0	2		1	4	1	5	4	2		1	2		0	
2001	18	0	0	0		1	3	1	4	4	2		1	2		0	
2002	21	0	0	1		1	3	1	4	4	2		1	3		1	
2003	17	0	0	0		1	3	1	3	3	1		1	2		2	
2004	18	0	0	1		1	3	1	4	3	2		1	1		1	
2005	14	0	0	1		0	3	1	3	2	1		1	2		0	
2006	13	0	0	0		1	3	1	3	3	1		0	1		0	
2007	14	0	0	0		0	3	1	3	2	1		1	2		1	
2008	13	0	0	1		0	3	1	2	2	1		1	1		1	
2009	9	0	0	0		0	2	1	2	2	1		0	1		0	
2010	2	0	0	0		0	0	0	0	0	0		1	1		0	
2011	10	0	0	0		0	2	1	2	2	1		0	1		1	
2012	7	0	0	1		0	1	0	1	1	0		1	1		1	
2013	8	0	0	0		0	2	0	2	2	1		0	1		0	
2014	2	0	0	0		0	0	0	0	0	0		0	1		1	
2015	3	0	0	0		0	1	0	1	1	0		0	0		0	
1985-2015	502	2	0	11	13	17	95	29	106	94	43	384	27	63	90	15	15
1985-2000	333	2	0	6	8	12	63	19	72	63	29	258	18	43	61	6	6

TABLE 4-15
($21/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - WITHIN 4-MILES
UNRESTRICTED ACTIVITY

OIL PRODUCING PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		16 WELLS	40 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	5	0	0	0		0	2	1	1	0	0		0	1		0	
1987	8	0	0	0		0	3	2	2	0	0		0	1		0	
1988	1	0	0	0		0	0	0	0	0	0		0	1		0	
1989	4	0	0	0		0	1	1	1	0	0		0	1		0	
1990	4	0	0	0		0	1	1	0	0	0		0	2		0	
1991	5	0	0	0		0	2	1	1	0	0		0	1		0	
1992	6	0	0	0		0	2	1	1	0	0		0	2		0	
1993	5	0	0	0		0	2	1	1	0	0		0	1		0	
1994	6	0	0	0		0	2	1	1	0	0		0	2		0	
1995	5	0	0	0		0	2	1	1	0	0		0	1		0	
1996	7	0	0	1		0	2	1	1	0	0		0	2		0	
1997	6	0	0	0		0	2	1	1	0	0		0	2		0	
1998	5	0	0	0		0	2	1	1	0	0		0	1		0	
1999	5	0	0	0		0	2	1	1	0	0		0	1		0	
2000	6	0	0	1		0	2	1	1	0	0		0	1		0	
2001	2	0	0	0		0	1	0	0	0	0		0	1		0	
2002	6	0	0	0		0	2	1	1	0	0		0	2		0	
2003	1	0	0	0		0	0	0	0	0	0		0	1		0	
2004	5	0	0	1		0	2	1	1	0	0		0	0		0	
2005	1	0	0	0		0	0	0	0	0	0		0	1		0	
2006	2	0	0	0		0	0	1	0	0	0		0	1		0	
2007	2	0	0	0		0	0	1	0	0	0		0	1		0	
2008	1	0	0	0		0	0	1	0	0	0		0	0		0	
2009	0	0	0	0		0	0	0	0	0	0		0	0		0	
2010	1	0	0	0		0	0	0	0	0	0		0	1		0	
2011	3	0	0	0		0	1	1	0	0	0		0	1		0	
2012	0	0	0	0		0	0	0	0	0	0		0	0		0	
2013	1	0	0	0		0	0	0	0	0	0		0	1		0	
2014	0	0	0	0		0	0	0	0	0	0		0	0		0	
2015	0	0	0	0		0	0	0	0	0	0		0	0		0	
1985-2015	103	0	0	3	3	0	33	21	16	0	0	70	0	30	30	0	0
1985-2000	78	0	0	2	2	0	27	15	14	0	0	56	0	20	20	0	0

TABLE 4-15 (Cont.)
($21/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - BEYOND 4-MILES
UNRESTRICTED ACTIVITY

OIL PRODUCING PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		16 WELLS	40 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	20	0	0	0		1	5	1	5	5	2		0	1		0	
1987	24	0	0	0		1	5	2	6	5	2		1	2		0	
1988	11	0	0	0		0	2	1	2	2	1		1	2		0	
1989	13	0	0	0		0	3	1	3	2	1		1	2		0	
1990	15	0	0	0		0	3	1	3	3	1		1	3		0	
1991	18	0	0	0		1	3	1	4	3	2		1	3		0	
1992	22	0	0	0		1	4	1	5	4	2		1	2		2	
1993	24	0	0	0		1	5	1	6	5	2		1	3		0	
1994	24	0	0	0		1	5	2	6	5	2		1	2		0	
1995	25	0	0	0		1	5	2	6	5	2		1	3		0	
1996	22	0	0	0		1	5	1	5	5	2		1	2		0	
1997	26	0	0	0		1	5	2	6	5	2		1	3		1	
1998	22	0	0	0		1	4	1	5	5	2		1	3		0	
1999	19	0	0	0		1	4	1	4	4	2		1	2		0	
2000	18	1	0	0		1	4	1	4	4	2		0	1		0	
2001	17	0	0	0		1	3	1	4	3	2		1	2		0	
2002	19	0	0	0		1	3	1	4	4	2		1	2		1	
2003	16	0	0	0		1	3	1	3	3	1		1	2		1	
2004	15	0	0	0		1	3	1	4	3	2		0	1		0	
2005	11	0	0	0		0	3	1	2	2	1		1	1		0	
2006	13	0	0	0		1	3	1	3	3	1		0	1		0	
2007	13	0	0	0		0	3	1	2	2	1		1	2		1	
2008	11	0	0	1		0	3	1	2	2	1		0	1		0	
2009	9	0	0	0		0	2	1	2	2	1		0	0		1	
2010	2	0	0	0		0	0	0	0	0	0		1	1		0	
2011	8	0	0	0		0	2	0	2	2	1		0	1		0	
2012	4	0	0	0		0	1	0	1	1	0		0	1		0	
2013	6	0	0	0		0	2	0	1	1	1		0	1		0	
2014	5	0	0	0		0	1	0	1	1	0		0	1		1	
2015	0	0	0	0		0	0	0	0	0	0		0	0		0	
1985-2015	452	1	0	1	2	17	94	28	101	91	41	372	19	51	70	8	8
1985-2000	303	1	0	0	1	12	62	19	70	62	27	252	13	34	47	3	3

Commission. Under section 6871.2 of the code, the legislature has prohibited the Commission from issuing oil and gas leases in certain areas along the coast (deemed "sanctuary zones"). In addition to these sanctuary zones, the State Lands Commission has declared that no new oil and gas leasing and development will take place in certain designated areas (calendar items adopted 10/26/88 and 12/6/89). These declarations have resulted in the inclusion of all remaining unleased submerged lands with those that are currently established as sanctuaries (Meier, 1990).

Recent actions by the State Lands Commission indicate that no further development will occur even in existing leases in State waters. In 1969, following a well blow-out in the Santa Barbara Channel, the State Lands Commission imposed a drilling moratorium on all State oil and gas leases in submerged lands. The Commission later began lifting the moratorium on a lease by lease basis; however, it has denied all applications for drilling permits in recent years. The most recent case was an application by Atlantic Richfield Co. (ARCO) in 1987 (case # 663 010). The court issued a ruling in January of this year supporting the Lands Commission's decision to deny the permit. (The Superior Court's official judgment, expected within the next several weeks, is expected to be similar to the initial ruling. The decision will certainly be appealed by ARCO; however, it is believed that the Lands Commission's decision to deny drilling permits will stand (Meier, 1990).) Given the recent actions by the State Lands Commission, the restricted projections include <u>no</u> activity in Pacific State waters.

<u>Federal Waters</u>

On June 26, 1990, President Bush announced his decision to implement a moratorium on oil and gas leasing and development in Federal waters off of California until the year 2000 (DOI, 1990). The moratorium eliminates the proposed leasing in sale areas 91 and 119, and the vast majority of sale area 95. This means that 99 percent of Federal waters off California are off-limits to leasing for the remainder of the century. The remaining 1 percent of tracts in the Southern California Planning Area, located in the Santa Maria Basin and the Santa Barbara Channel, will not be available until at least 1996, and only then <u>if</u> further studies indicate that development appears viable in relation to the environmental impacts and economic considerations. This means that the only exploration and development likely will occur on existing Federal leases.

The President indicated that, in the event of a national emergency, these restrictions on leasing could be lifted. Even if such an event occurred, the oil and gas industry, which was decimated during the oil price collapse of 1986, would be hard pressed to increase production in the short term due to the shortage of available equipment, personnel, and capital (OGJ, 1990). Nonetheless, the unrestricted platform projections reflect an upper bound for activity in the Pacific in the absence of any environmental or materiel constraints.

The President's decision also cancels lease sale 96, in the George's Bank region of the North Atlantic, and essentially prohibits any activity in this planning area until after the year 2000 (DOI, 1990). Given the cancellation of sale 96, the lack of sufficient infrastructure to support production in the region, and the prevailing attitudes opposing offshore drilling, we have deleted all Atlantic activity in the restricted projections.

4.4.2 Implications for Platform Projections

The MMS production projections will remain the basis of the restricted activity projections for the Gulf and Alaska regions. However, ERG has made several assumptions regarding the Pacific and Atlantic regions to reflect recent legislative actions:

- All future activity in State waters off California will equal zero.
- Activity in Federal waters off California will be limited to platforms installed between 1985 and 1989, since wells in these platforms will be drilled during the 1986-2000 time period (see Table 4-16.).
- All future activity in the Atlantic region will equal zero.

Table 4-16 indicates that a total of seven platforms will be considered as part of the restricted activity scenario in the Pacific region under the $21/bbl assumption. All of these platforms fall outside of the 4-mile regulatory boundary. The average annual number of wells drilled in the Pacific during the 1986 to 1989 period is 32 (see Table 4-17). ERG believes this number accurately reflects the number of wells to be drilled under current restrictions. Assuming this level of activity continues throughout the 15-year period, it will result in a total of 480 wells. This number is sufficient to address the needs of the productive and exploratory wells of the platforms listed in Table 4-16.

TABLE 4-16

PACIFIC PLATFORMS CONSIDERED IN RESTRICTED DEVELOPMENT ANALYSIS
FEDERAL WATERS

Platform Name	Year Installed	Year of Production**	Number of Well Slots	ERG Model Type
Irene	1985	1987	72	Pacific 70
Gail	1987	1988	36	Pacific 40
Harvest	1985ø	1991	50	Pacific 40
Hermosa	1985ø	1991	48	Pacific 40
Hidalgo	1986ø	1991	56	Pacific 70
Harmony	1989ø *	1992	60	Pacific 70
Heritage	1989ø *	1992	60	Pacific 70
Total Projected Well Slots			382	

ø These platforms are not yet producing.
* Platforms Harmony and Heritage were not completed as of 10/90.
** ERG estimates.

Sources: CCC, 1988; MMS, 1990a; and Winham, 1990.

TABLE 4-17

ACTUAL DRILLING RATES FOR THE PACIFIC - 1986-1989

	Year				
	1986	1987	1988	1989	Average
Exploratory	3	4	3	5	4
Development	34	39	29	11	28
Total	37	43	32	16	32

Source: MMS, 1990b.

Recent events suggest that production in the Atlantic region will not occur before the turn of the century; thus, activity in this region has been excluded from the restricted projections as well.

Table 4-18 summarizes the methodology for allocating wells to platforms. This configuration remains the same as under the unrestricted development scenario, except that the Atlantic region has been eliminated and activity in the Pacific is limited to seven platforms, including four 70 well slot structures.

Using these restricted assumptions, two sets of platform projections were created as shown in Tables 4-19 and 4-20. The projections under the $21/bbl scenario are shown in Table 4-19, while those under the $15/bbl scenario are in Table 4-20. The $15/bbl projections represent the low estimate of the number of platforms expected to begin production during the 1986-2000 period, and therefore would produce the lowest total regulatory costs. Note that under the $15/bbl assumption:

- The number of platforms in the Atlantic remains zero.
- Activity in the Pacific remains the same as under the $21/bbl scenario. (This occurs because the platforms from which production is projected are either completed or near completion. Therefore, these companies would continue to utilize these platforms to recover the costs already incurred.)
- The only changes occur in the Gulf and Alaska regions, since that is where the decline in oil prices would negatively affect the viability of projects.

Table 4-21 shows platform distribution within and beyond 4 miles from shore. Table 4-22 repeats this information for oil producing platforms only.

4.5 SUMMARY

Tables 4-23 through 4-26 summarize the platform projections under the four alternative scenarios. Note that, assuming $21/bbl, the total number of platforms set during the 1986-2000 time period drops from 851 to 766 when activity is restricted. The platform projections for the high and low case scenarios are shown in Tables 4-25 and 4-26, respectively. The average annual number of wells drilled under each of the four scenarios is summarized in Table 4-27. The number of wells has been back-calculated from the platform distribution. Since only whole platforms are assigned to a region in any given year, some rounding differences occur between the numbers in Table 4-27

TABLE 4-18

PLATFORM CONFIGURATION SUMMARY

RESTRICTED ACTIVITY

			PERCENT ALLOCATION OF REGIONAL PLATFORMS				PERCENT ALLOCATION OF REGIONAL WELLS			
			FEDERAL WATERS		STATE WATERS		FEDERAL WATERS		STATE WATERS	
REGION	WELL SLOTS	ACTIVE WELLS	OIL	GAS	OIL	GAS	OIL	GAS	OIL	GAS
GULF	1	1	5%	15%	5%	15%	0.4%	2%	1%	3%
	4	4	32%	35%	32%	53%	9%	18%	19%	31%
	6	6	8%	17%	38%	50%	4%	13%	35%	66%
	12	10	25%	22%	25%	0%	22%	34%	45%	0%
	24	18	20%	11%	0%	0%	35%	34%	0%	0%
	40	32	10%	0%	0%	0%	29%	0%	0%	0%
Alaska	24	18	15%	0%	0%	0%	15%	0%	0%	0%
	12	10	0%	100%	0%	0%	0%	100%	0%	0%
	48(a)	40	85%	0%	100%	0%	85%	0%	100%	0%

Note: For the Pacific region, projections include only those platforms installed during the 1985-1990 time period. For the Atlantic, no development was assumed.

(a) For platforms within 4-miles, a gravel island was utilized.

Source: ERG estimates based on MMS data.

TABLE 4-19
($21/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - TOTAL
RESTRICTED ACTIVITY

ALL PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		40 WELLS	70 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	53	0	0	0		6	17	8	12	8	2		0	0		0	
1987	61	0	0	0		6	18	10	15	9	2		0	1		0	
1988	12	0	0	0		0	3	2	3	2	1		1	0		0	
1989	28	0	0	0		2	9	5	7	4	1		0	0		0	
1990	32	0	0	0		2	11	6	7	5	1		0	0		0	
1991	50	0	0	0		5	15	8	11	6	2		2	1		0	
1992	63	0	0	0		7	19	10	14	9	2		0	2		0	
1993	59	0	0	0		6	18	9	15	9	2		0	0		0	
1994	68	0	0	0		7	21	12	16	10	2		0	0		0	
1995	55	0	0	0		5	17	8	14	9	2		0	0		0	
1996	60	0	0	1		6	19	9	14	9	2		0	0		0	
1997	59	0	0	0		6	18	10	14	9	2		0	0		0	
1998	58	0	1	0		6	17	9	14	9	2		0	0		0	
1999	54	0	0	0		6	17	9	12	8	2		0	0		0	
2000	54	1	0	1		6	16	8	12	8	2		0	0		0	
2001	38	0	0	0		4	12	5	9	6	2		0	0		0	
2002	45	0	0	0		4	14	7	11	7	2		0	0		0	
2003	38	0	0	0		4	12	6	9	6	1		0	0		0	
2004	42	0	0	1		4	13	6	10	6	2		0	0		0	
2005	32	0	0	0		3	11	5	7	5	1		0	0		0	
2006	29	0	0	0		3	8	5	7	5	1		0	0		0	
2007	26	0	0	0		2	8	5	6	4	1		0	0		0	
2008	25	0	0	1		2	7	5	5	4	1		0	0		0	
2009	21	0	0	0		2	6	3	5	4	1		0	0		0	
2010	9	0	0	0		1	3	2	2	1	0		0	0		0	
2011	19	0	0	0		1	6	3	5	3	1		0	0		0	
2012	11	0	0	0		1	3	2	3	2	0		0	0		0	
2013	5	0	0	0		0	2	0	1	1	1		0	0		0	
2014	9	0	0	0		1	3	1	2	2	0		0	0		0	
2015	7	0	0	0		1	2	1	2	1	0		0	0		0	
1985-2015	1122	1	1	4	6	109	345	179	264	171	41	1109	3	4	7	0	0
1985-2000	766	1	1	2	4	76	235	123	180	114	27	755	3	4	7	0	0

TABLE 4-20
($15/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - TOTAL
RESTRICTED ACTIVITY

ALL PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		40 WELLS	70 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	48	0	0	0		5	14	8	12	7	2		0	0		0	
1987	49	0	0	0		5	14	8	11	8	2		0	1		0	
1988	13	0	0	0		1	3	3	2	2	1		1	0		0	
1989	23	0	0	0		1	8	4	6	3	1		0	0		0	
1990	31	0	0	0		3	10	6	7	4	1		0	0		0	
1991	45	0	0	0		5	12	8	10	6	1		2	1		0	
1992	57	0	0	0		6	17	9	13	8	2		0	2		0	
1993	51	0	0	0		5	16	7	13	8	2		0	0		0	
1994	59	0	0	0		6	19	9	14	9	2		0	0		0	
1995	51	0	0	0		5	16	8	12	8	2		0	0		0	
1996	52	0	0	0		5	16	8	13	8	2		0	0		0	
1997	49	0	0	0		5	15	8	11	8	2		0	0		0	
1998	52	0	0	0		5	16	9	12	8	2		0	0		0	
1999	48	0	0	0		5	15	8	11	7	2		0	0		0	
2000	41	0	0	0		4	13	6	10	6	2		0	0		0	
2001	35	0	0	0		4	11	5	8	6	1		0	0		0	
2002	42	0	0	0		4	13	6	10	7	2		0	0		0	
2003	33	0	0	0		3	11	5	8	5	1		0	0		0	
2004	36	0	0	0		4	11	6	8	6	1		0	0		0	
2005	30	0	0	0		2	10	6	7	4	1		0	0		0	
2006	27	0	0	0		2	8	5	6	5	1		0	0		0	
2007	23	0	0	0		2	6	5	5	4	1		0	0		0	
2008	20	0	0	0		2	6	2	5	4	1		0	0		0	
2009	21	0	0	0		2	7	4	4	3	1		0	0		0	
2010	6	0	0	0		1	2	1	1	1	0		0	0		0	
2011	15	0	0	0		1	5	1	4	3	1		0	0		0	
2012	8	0	0	0		1	3	1	2	1	0		0	0		0	
2013	6	0	0	0		0	2	0	2	1	1		0	0		0	
2014	8	0	0	0		1	2	3	1	1	0		0	0		0	
2015	9	0	0	0		1	3	1	2	2	0		0	0		0	
1985-2015	988	0	0	0	0	96	304	160	230	153	38	981	3	4	7	0	0
1985-2000	669	0	0	0	0	66	204	109	157	100	26	662	3	4	7	0	0

TABLE 4-21
($15/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - WITHIN 4-MILES
RESTRICTED ACTIVITY

ALL PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		40 WELLS	70 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	10	0	0	0		2	4	3	1	0	0		0	0		0	
1987	11	0	0	0		2	4	4	1	0	0		0	0		0	
1988	2	0	0	0		0	0	2	0	0	0		0	0		0	
1989	6	0	0	0		0	3	2	1	0	0		0	0		0	
1990	5	0	0	0		1	2	2	0	0	0		0	0		0	
1991	9	0	0	0		2	3	3	1	0	0		0	0		0	
1992	12	0	0	0		2	5	4	1	0	0		0	0		0	
1993	8	0	0	0		1	4	2	1	0	0		0	0		0	
1994	11	0	0	0		2	5	3	1	0	0		0	0		0	
1995	9	0	0	0		1	4	3	1	0	0		0	0		0	
1996	9	0	0	0		1	4	3	1	0	0		0	0		0	
1997	8	0	0	0		1	4	3	0	0	0		0	0		0	
1998	9	0	0	0		1	4	3	1	0	0		0	0		0	
1999	8	0	0	0		1	4	3	0	0	0		0	0		0	
2000	7	0	0	0		1	3	2	1	0	0		0	0		0	
2001	4	0	0	0		1	2	1	0	0	0		0	0		0	
2002	7	0	0	0		1	3	2	1	0	0		0	0		0	
2003	4	0	0	0		1	2	1	0	0	0		0	0		0	
2004	5	0	0	0		1	2	2	0	0	0		0	0		0	
2005	4	0	0	0		0	2	2	0	0	0		0	0		0	
2006	3	0	0	0		0	1	2	0	0	0		0	0		0	
2007	3	0	0	0		0	1	2	0	0	0		0	0		0	
2008	1	0	0	0		0	1	0	0	0	0		0	0		0	
2009	5	0	0	0		0	3	2	0	0	0		0	0		0	
2010	0	0	0	0		0	0	0	0	0	0		0	0		0	
2011	1	0	0	0		0	1	0	0	0	0		0	0		0	
2012	0	0	0	0		0	0	0	0	0	0		0	0		0	
2013	0	0	0	0		0	0	0	0	0	0		0	0		0	
2014	2	0	0	0		0	0	2	0	0	0		0	0		0	
2015	0	0	0	0		0	0	0	0	0	0		0	0		0	
1985-2015	163	0	0	0	0	22	71	58	12	0	0	163	0	0	0	0	0
1985-2000	124	0	0	0	0	18	53	42	11	0	0	124	0	0	0	0	0

TABLE 4-21 (Cont.)
($15/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - BEYOND 4-MILES
RESTRICTED ACTIVITY

ALL PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		40 WELLS	70 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	38	0	0	0		3	10	5	11	7	2		0	0		0	
1987	38	0	0	0		3	10	4	10	8	2		0	1		0	
1988	11	0	0	0		1	3	1	2	2	1		1	0		0	
1989	17	0	0	0		1	5	2	5	3	1		0	0		0	
1990	26	0	0	0		2	8	4	7	4	1		0	0		0	
1991	36	0	0	0		3	9	5	9	6	1		2	1		0	
1992	45	0	0	0		4	12	5	12	8	2		0	2		0	
1993	43	0	0	0		4	12	5	12	8	2		0	0		0	
1994	48	0	0	0		4	14	6	13	9	2		0	0		0	
1995	42	0	0	0		4	12	5	11	8	2		0	0		0	
1996	43	0	0	0		4	12	5	12	8	2		0	0		0	
1997	41	0	0	0		4	11	5	11	8	2		0	0		0	
1998	43	0	0	0		4	12	6	11	8	2		0	0		0	
1999	40	0	0	0		4	11	5	11	7	2		0	0		0	
2000	34	0	0	0		3	10	4	9	6	2		0	0		0	
2001	31	0	0	0		3	9	4	8	6	1		0	0		0	
2002	35	0	0	0		3	10	4	9	7	2		0	0		0	
2003	29	0	0	0		2	9	4	8	5	1		0	0		0	
2004	31	0	0	0		3	9	4	8	6	1		0	0		0	
2005	26	0	0	0		2	8	4	7	4	1		0	0		0	
2006	24	0	0	0		2	7	3	6	5	1		0	0		0	
2007	20	0	0	0		2	5	3	5	4	1		0	0		0	
2008	19	0	0	0		2	5	2	5	4	1		0	0		0	
2009	16	0	0	0		2	4	2	4	3	1		0	0		0	
2010	6	0	0	0		1	2	1	1	1	0		0	0		0	
2011	14	0	0	0		1	4	1	4	3	1		0	0		0	
2012	8	0	0	0		1	3	1	2	1	0		0	0		0	
2013	6	0	0	0		0	2	0	2	1	1		0	0		0	
2014	6	0	0	0		1	2	1	1	1	0		0	0		0	
2015	9	0	0	0		1	3	1	2	2	0		0	0		0	
1985-2015	825	0	0	0	0	74	233	102	218	153	38	818	3	4	7	0	0
1985-2000	545	0	0	0	0	48	151	67	146	100	26	538	3	4	7	0	0

TABLE 4-22
($15/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - WITHIN 4-MILES
RESTRICTED ACTIVITY

OIL PRODUCING PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		40 WELLS	70 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	4	0	0	0		0	2	1	1	0	0		0	0		0	
1987	5	0	0	0		0	2	2	1	0	0		0	0		0	
1988	1	0	0	0		0	0	1	0	0	0		0	0		0	
1989	3	0	0	0		0	1	1	1	0	0		0	0		0	
1990	1	0	0	0		0	0	1	0	0	0		0	0		0	
1991	3	0	0	0		0	1	1	1	0	0		0	0		0	
1992	4	0	0	0		0	2	1	1	0	0		0	0		0	
1993	4	0	0	0		0	2	1	1	0	0		0	0		0	
1994	4	0	0	0		0	2	1	1	0	0		0	0		0	
1995	4	0	0	0		0	2	1	1	0	0		0	0		0	
1996	4	0	0	0		0	2	1	1	0	0		0	0		0	
1997	3	0	0	0		0	2	1	0	0	0		0	0		0	
1998	4	0	0	0		0	2	1	1	0	0		0	0		0	
1999	3	0	0	0		0	2	1	0	0	0		0	0		0	
2000	4	0	0	0		0	2	1	1	0	0		0	0		0	
2001	0	0	0	0		0	0	0	0	0	0		0	0		0	
2002	4	0	0	0		0	2	1	1	0	0		0	0		0	
2003	0	0	0	0		0	0	0	0	0	0		0	0		0	
2004	2	0	0	0		0	1	1	0	0	0		0	0		0	
2005	2	0	0	0		0	1	1	0	0	0		0	0		0	
2006	1	0	0	0		0	0	1	0	0	0		0	0		0	
2007	1	0	0	0		0	0	1	0	0	0		0	0		0	
2008	0	0	0	0		0	0	0	0	0	0		0	0		0	
2009	2	0	0	0		0	1	1	0	0	0		0	0		0	
2010	0	0	0	0		0	0	0	0	0	0		0	0		0	
2011	0	0	0	0		0	0	0	0	0	0		0	0		0	
2012	0	0	0	0		0	0	0	0	0	0		0	0		0	
2013	0	0	0	0		0	0	0	0	0	0		0	0		0	
2014	1	0	0	0		0	0	1	0	0	0		0	0		0	
2015	0	0	0	0		0	0	0	0	0	0		0	0		0	
1985-2015	64	0	0	0	0	0	29	23	12	0	0	64	0	0	0	0	0
1985-2000	51	0	0	0	0	0	24	16	11	0	0	51	0	0	0	0	0

TABLE 4-22 (Cont.)
($15/bbl of oil - 1986 dollars)

PLATFORM PROJECTIONS - BEYOND 4-MILES
RESTRICTED ACTIVITY

OIL PRODUCING PROJECTS

		ALASKA				GULF							PACIFIC			ATLANTIC	
YEAR	TOTAL	24 WELLS	12 WELLS	48 WELLS		1 WELL	4 WELLS	6 WELLS	12 WELLS	24 WELLS	40 WELLS		40 WELLS	70 WELLS		24 WELLS	
1985	0	0	0	0		0	0	0	0	0	0		0	0		0	
1986	17	0	0	0		1	4	1	5	4	2		0	0		0	
1987	19	0	0	0		1	4	1	5	5	2		0	1		0	
1988	6	0	0	0		0	2	0	1	1	1		1	0		0	
1989	10	0	0	0		0	3	1	3	2	1		0	0		0	
1990	10	0	0	0		0	3	1	3	2	1		0	0		0	
1991	15	0	0	0		1	3	1	3	3	1		2	1		0	
1992	19	0	0	0		1	4	1	5	4	2		0	2		0	
1993	17	0	0	0		1	4	1	5	4	2		0	0		0	
1994	19	0	0	0		1	5	1	5	5	2		0	0		0	
1995	17	0	0	0		1	4	1	5	4	2		0	0		0	
1996	17	0	0	0		1	4	1	5	4	2		0	0		0	
1997	18	0	0	0		1	4	1	5	5	2		0	0		0	
1998	16	0	0	0		1	4	1	4	4	2		0	0		0	
1999	14	0	0	0		1	3	1	4	3	2		0	0		0	
2000	14	0	0	0		1	3	1	4	3	2		0	0		0	
2001	12	0	0	0		1	3	1	3	3	1		0	0		0	
2002	15	0	0	0		1	3	1	4	4	2		0	0		0	
2003	10	0	0	0		0	3	1	3	2	1		0	0		0	
2004	12	0	0	0		1	3	1	3	3	1		0	0		0	
2005	10	0	0	0		0	3	1	3	2	1		0	0		0	
2006	11	0	0	0		0	3	1	3	3	1		0	0		0	
2007	8	0	0	0		0	2	1	2	2	1		0	0		0	
2008	7	0	0	0		0	2	0	2	2	1		0	0		0	
2009	4	0	0	0		0	1	0	1	1	1		0	0		0	
2010	0	0	0	0		0	0	0	0	0	0		0	0		0	
2011	7	0	0	0		0	2	0	2	2	1		0	0		0	
2012	2	0	0	0		0	1	0	1	0	0		0	0		0	
2013	6	0	0	0		0	2	0	2	1	1		0	0		0	
2014	0	0	0	0		0	0	0	0	0	0		0	0		0	
2015	3	0	0	0		0	1	0	1	1	0		0	0		0	
1985-2015	335	0	0	0	0	15	83	21	92	79	38	328	3	4	7	0	0
1985-2000	228	0	0	0	0	12	54	14	62	53	26	221	3	4	7	0	0

TABLE 4-23

TOTAL PROJECTED NSPS STRUCTURES (1986-2000)
UNRESTRICTED ACTIVITY

$21/bbl SCENARIO

Region	Model	All Platforms			Within 4-Miles			Beyond 4-Miles		
		Total	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas
Gulf										
	Gulf 1b	76	12	64	23	0	23	53	12	41
	Gulf 4	235	89	146	60	27	33	175	62	113
	Gulf 6	123	34	89	43	15	28	80	19	61
	Gulf 12	180	84	96	14	14	0	166	70	96
	Gulf 24	114	62	52	0	0	0	114	62	52
	Gulf 40	27	27	0	0	0	0	27	27	0
	Gulf Totals	755	308	447	140	56	84	615	252	363
Pacific										
	Pacific 16	30	13	17	0	0	0	30	13	17
	Pacific 40	54	54	0	20	20	0	34	34	0
	Pacific Totals	84	67	17	20	20	0	64	47	17
Atlantic										
	Atlantic 24	8	3	5	0	0	0	8	3	5
Alaska										
	Cook Inlet 12	1	0	1	0	0	0	1	0	1
	Cook Inlet 24	1	1	0	0	0	0	1	1	0
	B. Gravel Island*	2	2	0	2	2	0	0	0	0
	Alaska Totals	4	3	1	2	2	0	2	1	
Total Platforms - All Regions		851	381	470	162	78	84	689	303	386

* Oil only; all other projects are assumed to produce oil and casinghead gas.

TABLE 4-24

TOTAL PROJECTED NSPS STRUCTURES (1986-2000)
RESTRICTED ACTIVITY

$21/bbl SCENARIO

Region	Model	All Platforms			Within 4-Miles			Beyond 4-Miles		
		Total	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas
Gulf										
	Gulf 1b	76	12	64	23	0	23	53	12	41
	Gulf 4	235	89	146	60	27	33	175	62	113
	Gulf 6	123	34	89	43	15	28	80	19	61
	Gulf 12	180	84	96	14	14	0	166	70	96
	Gulf 24	114	62	52	0	0	0	114	62	52
	Gulf 40	27	27	0	0	0	0	27	27	0
	Gulf Totals	755	308	447	140	56	84	615	252	363
Pacific										
	Pacific 40	3	3	0	0	0	0	3	3	0
	Pacific 70	4	4	0	0	0	0	4	4	0
	Pacific Totals	7	7	0	0	0	0	7	7	0
Atlantic										
	Atlantic 24	0	0	0	0	0	0	0	0	0
Alaska										
	Cook Inlet 12	1	0	1	0	0	0	1	0	1
	Cook Inlet 24	1	1	0	0	0	0	1	1	0
	B. Gravel Island*	2	2	0	2	2	0	0	0	0
	Alaska Totals	4	3	1	2	2	0	2	1	1
Total Platforms - All Regions		766	318	448	142	58	84	624	260	364

* Oil only; all other projects are assumed to produce oil and casinghead gas.

TABLE 4-25

TOTAL PROJECTED NSPS STRUCTURES (1986-2000)
UNRESTRICTED ACTIVITY - (HIGH DEVELOPMENT SCENARIO)

$32/bbl SCENARIO

Region	Model	All Platforms			Within 4-Miles			Beyond 4-Miles		
		Total	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas
Gulf										
	Gulf 1b	80	12	68	25	0	25	55	12	43
	Gulf 4	241	90	151	61	27	34	180	63	117
	Gulf 6	127	36	91	46	17	29	81	19	62
	Gulf 12	183	86	97	14	14	0	169	72	97
	Gulf 24	118	63	55	0	0	0	118	63	55
	Gulf 40	29	29	0	0	0	0	29	29	0
	Gulf Totals	778	316	462	146	58	88	632	258	374
Pacific										
	Pacific 16	40	18	22	0	0	0	40	18	22
	Pacific 40	68	68	0	25	25	0	43	43	0
	Pacific Totals	108	86	22	25	25	0	83	61	22
Atlantic										
	Atlantic 24	15	6	9	0	0	0	15	6	9
Alaska										
	Cook Inlet 12	4	0	4	0	0	0	4	0	4
	Cook Inlet 24	2	2	0	0	0	0	2	2	0
	B. Gravel Island*	24	24	0	18	18	0	6	6	0
	Alaska Totals	30	26	4	18	18	0	12	8	4
Total Platforms - All Regions		931	434	497	189	101	88	742	333	409

* Oil only.

TABLE 4-26

TOTAL PROJECTED NSPS STRUCTURES (1986-2000)
RESTRICTED ACTIVITY - (LOW DEVELOPMENT SCENARIO)

$15/bbl SCENARIO

		All Platforms			Within 4-Miles			Beyond 4-Miles		
Region	Model	Total	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas
Gulf										
	Gulf 1b	66	12	54	18	0	18	48	12	36
	Gulf 4	204	78	126	53	24	29	151	54	97
	Gulf 6	109	30	79	42	16	26	67	14	53
	Gulf 12	157	73	84	11	11	0	146	62	84
	Gulf 24	100	53	47	0	0	0	100	53	47
	Gulf 40	26	26	0	0	0	0	26	26	0
	Gulf Totals	662	272	390	124	51	73	538	221	317
Pacific										
	Pacific 40	3	3	0	0	0	0	3	3	0
	Pacific 70	4	4	0	0	0	0	4	4	0
	Pacific Totals	7	7	0	0	0	0	7	7	0
Atlantic										
	Atlantic 24	0	0	0	0	0	0	0	0	0
Alaska										
	Cook Inlet 12	0	0	0	0	0	0	0	0	0
	Cook Inlet 24	0	0	0	0	0	0	0	0	0
	B. Gravel Island*	0	0	0	0	0	0	0	0	0
	Alaska Totals	0	0	0	0	0	0	0	0	0
Total Platforms - All Regions		669	279	390	124	51	73	545	228	317

* Oil only.

TABLE 4-27

AVERAGE ANNUAL NUMBER OF WELLS DRILLED, BAT AND NSPS

Scenario	Region				Total
	Gulf	Pacific	Alaska	Atlantic	
$32/bbl - Unrestricted Development					
Average Annual Number of Wells	741	302	105	30	1,178
Percentage Within 4 Miles of Shore	10%	30%	75%	0%	21%
Number Within 4 Miles of Shore	74	91	79	0	243
Number Beyond 4 Miles of Shore	667	211	26	30	935
$21/bbl - Unrestricted Development					
Average Annual Number of Wells	715	237	12	16	980
Percentage Within 4 Miles of Shore	10%	30%	75%	0%	15%
Number Within 4 Miles of Shore	72	71	9	0	152
Number Beyond 4 Miles of Shore	643	166	3	16	828
$21/bbl - Restricted Development					
Average Annual Number of Wells	715	32	12	0	759
Percentage Within 4 Miles of Shore	10%	0%	75%	NA	11%
Number Within 4 Miles of Shore	72	0	9	0	81
Number Beyond 4 Miles of Shore	643	32	3	0	678
$15/bbl - Restricted Development					
Average Annual Number of Wells	638	32	0	0	670
Percentage Within 4 Miles of Shore	10%	0%	NA	NA	10%
Number Within 4 Miles of Shore	64	0	0	0	64
Number Beyond 4 Miles of Shore	574	32	0	0	606

NA: Not Applicable 08-Feb-91

Source: ERG estimates

Note: Totals may not agree with Table 4-8 counts due to rounding.

and Table 4-8. It should be noted that, under the $21/bbl restricted development scenario, 759 wells per year are projected. For comparison, the most recent prodiction for offshore wells drilled in 1991 is 749 wells (Petzet, 1990).

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SECTION FIVE

ECONOMIC METHODOLOGY

This section describes the model that has been developed to simulate the economic performance of offshore drilling and production projects. Thirty-four projects are constructed to reflect cost and productivity differences throughout the country. Costs for current practices for the disposal of drilling and production wastes are incorporated into the 34 baseline projects. Section 5.1 presents a description of the economic simulation methodology while the 34 regional projects are described in Section 5.2. The baseline summary financial statistics for NSPS projects are given in Section 5.3 while those for BAT projects are listed in Section 5.4.

Ten appendices to this section provide details of all the data sets and calculations described in summary fashion in the report text (Appendices A through J). These appendices also describe the input data and algorithm logic of the baseline economic cases.

5.1 DESCRIPTION OF THE ECONOMIC MODEL

To estimate the effects of the regulatory approaches, the economic performance of model projects is simulated before and after new pollution control requirements. This section reviews the economic model and its components.

5.1.1 Economic Model Overview

The economic model simulates the performance and measures the profitability of a petroleum production project. For the purposes of this report, a project is defined as a single platform or island. For each project, economic data representing typical costs for leasing, exploration, delineation, production, and operating are entered, as well as typical production rates, oil and gas selling prices, and other pertinent data. The model calculates the annual after-tax cash flow for each year of operation, as well as cumulative (i.e., lifetime) measures of a project's performance such as net present value (NPV) and internal rate of return (IRR).

The schematic design of the model is summarized in Figure 5-1. Two sets of exogenous values -- project-specific and general-model variables -- are entered into the model. The model provides the integrative calculation procedures and algorithms that duplicate (1) the oil industry's standard accounting procedures, (2) federal taxation rules after the Tax Reform Act of 1986, and (3) standard financial rate-of-return calculation methods. The outputs of the economic model are a series of yearly project cash flows and cumulative performance measures.

The regulatory approaches are incorporated into the economic model by adding relevant capital costs and operating expenses to the set of cost data. The model calculates all yearly and cumulative outputs for both the base case and regulated cases for each project.

5.1.2 Parameter Description

A distinct set of parameter values is required for each of the model projects and constitutes a complete economic description of each project. The following categories of parameters are incorporated into each project:

1. Lease Cost - Bonus payments to Federal or state governments or to private individuals for the land.
2. Geological and Geophysical Cost - Cost of analytic work prior to drilling.
3. Drilling Cost per Well.
4. Cost of Production Equipment.
5. Discovery Efficiency - The number of wells drilled for one successful well.
6. Production Rates - Initial production rates of oil and gas and production decline rates.
7. Operation and Maintenance Costs.
8. Tax Rates - Rates for: Federal and state income taxes, severance taxes, royalty payments, depreciation, and depletion.
9. Price - Wellhead selling price of oil and gas (also called the "first purchase price" of the product).
10. Cost of Capital - Real rate of return for the industry.
11. Timing - Length of time required for each project phase (i.e. leasing, exploration, delineation, development, and production).

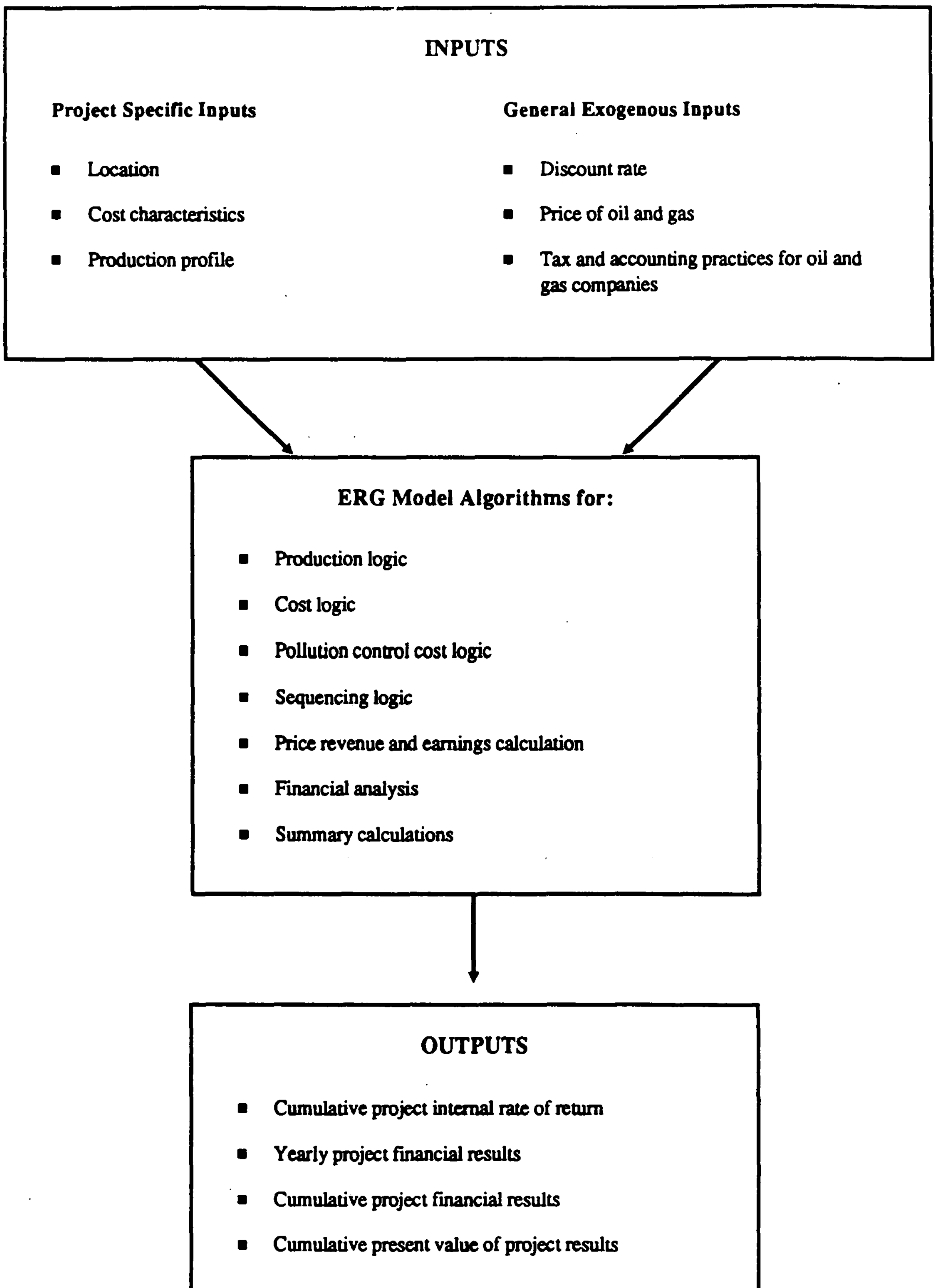

Figure 5-1. General schematic diagram of ERG economic model.

The parameter values used in the analysis are summarized in Section 5.2 and described more fully in Appendices A through I.

5.1.3 Model Calculation Procedures

The model's calculational procedures are a set of rules and logic used to convert the project parameters into measures of a project's financial performance. These procedures fall into several categories:

Sequencing Logic - The economic model includes a scheduling sequence for each phase of a project life: leasing, exploration, delineation, development, and production. Project lead times range from as little as one year for small single-well platforms in the Gulf of Mexico to 12 years for a deep-water platform in Arctic Alaska.

Production Logic - The model equations use exogenous values for peak production rates and production decline rates to define a production profile for the well. Summary measures of production for the entire project lifetime are also calculated.

Cost Logic - The model equations use exogenous cost data to define yearly capital and operating costs of each project. Exogenous parameters include capital cost (e.g., leasehold costs, geological and geophysical costs, drilling cost, and production equipment cost) and operating costs. Using the model sequencing logic, the exogenous cost information is converted to annual capital and operating cost streams. Summary measures of all capital and operating costs are calculated for the entire project lifetime.

Pollution Control Cost Logic - A set of equations incorporates the capital and operating costs of additional pollution control approaches into the project cost stream, thus creating a simulation of the economic effect of alternative regulatory approaches.

Cost Accounting Practices - Specialized oil industry accounting procedures are applied to project cost streams. Capital and operating costs are treated in accordance with oil industry accounting practices. The model calculates the expensed and capitalized portions of each capital expenditure, which in turn are used as a base to estimate depreciation for each year of the project's life. Cost accounting practices hold for both onshore and offshore operations with a distinction being made that costs such as labor, fuel, etc., incurred in the construction of offshore platform be considered as intangible drilling costs (Houghton 1987). Firms with both "upstream" activities -- exploration, development, and production -- and "downstream" activities -- transportation, refining and marketing -- are called major integrated oil companies (the "majors"). Majors expense 70 percent of intangible drilling costs. Depletion allowances, which are also credited to the project, are calculated on a cost basis for majors.

Firms with only "upstream" activities are called independents. Cost accounting practices differ for independents -- they may expense 100 percent of intangible drilling costs and may take a depletion allowance on either a cost or percentage basis. Since most activity in the offshore regions is performed by major oil companies, the analysis incorporates those cost accounting measures. Independents play a larger role in coastal oil and gas operations. An investigation of coastal operations may warrant consideration of the alternate cost accounting practices appropriate for independents.

<u>Price and Revenue Calculations</u> - The wellhead price (also known as a "first purchase price") of oil and gas is an exogenous parameter for the model. These vary by region; see Section 5.2. The prices are multiplied by the annual production volumes to calculate annual project revenues. Revenues are calculated both as an annual stream and as a total for project lifetime.

<u>Earnings and Cash Flow Analysis</u> - The model calculates a project's annual earnings, which are the difference between a project's revenues and its costs. Tax and royalty payments are subtracted from before-tax earnings to calculate annual cash flow. Depreciation and depletion are treated in these calculations according to Federal laws. For the sake of simplicity, all severance taxes are calculated as a percentage of gross income minus royalties. This is the most common situation, although some states calculate severance taxes on a fee-per-unit-production basis (e.g., $0.075 per Mcf).

<u>Financial Performance Calculations</u> - A variety of summary financial measures are calculated in the model. Annual project cash flows are discounted to the present using an 8 percent discount rate to calculate to net present value (NPV) of the project. The internal rate of return (i.e., the discount rate at which the present value of the project is zero) is also calculated. The present value of all project costs is divided by the present value of all petroleum production to calculate the average cost per unit of production.

5.1.4 Interpretation of Model Results

Based on the economic model logic described above, a number of summary statistics and performance measures are calculated for each project, including:

1. Internal rate of return (IRR).
2. Corporate cost per unit of production.
3. Production cost per unit of production.
4. Net present value (NPV).
5. Present value equivalent of production.
6. Present value of all project costs.
7. Present value of all project revenues.
8. Present value of additional pollution control costs.

The analysis of the economic status of the base cases, presented in Section 5.2, focuses on the first five parameters listed above as performance measures.

The <u>internal rate of return</u> of a project is a measure of its profitability. If the IRR of a project is greater than the corporation's actual cost of capital, the project is profitable. In this analysis, the real cost of capital is valued at 8 percent. Thus, projects with a real IRR higher than 8 percent are considered profitable. The internal rate of return should not be confused with a "hurdle rate." The latter is a projected rate of return that must be exceeded before a company is willing to undertake a project. Hurdle rates will vary by company.

The <u>corporate cost of production</u> is defined as the present value of all net corporate cash outflows for the project life (i.e., the cost of leasing, exploration, development, operating, royalties, severance tax and income tax payments, adjusted for the tax savings due to depreciation and depletion) divided by the present value of all production (e.g., barrel-of-oil equivalent of oil and gas production). The present value calculations use a cost-of-capital interest rate of 8 percent to discount costs, cash flow, and production. If the corporate cost per unit of production is lower than the projected wellhead selling price, the project is considered viable.

The production cost per unit of production is a measure of the value of net social resources expended in the development and operation of offshore petroleum projects. The difference between company cost and production cost is that production cost ignores the effect of transfers that do not use social resources, such as income taxes, revenue taxes, and royalties. Included in the calculation of this cost are the present values of: all investment costs, operating costs, and geological/geophysical expenses. The sum of these costs is divided by the present value equivalent of production to obtain production cost.

The net present value (NPV) is calculated as the difference between then present values of all cash inflows and all cash outflows. A positive value is indicative that a project generates more revenues than investing the capital elsewhere in a different opportunity with an expected rate of return equal to the cost of capital used in this analysis.

In interpreting the summary statistics from the model simulations, several factors must be considered. First, the input data are of varying quality. There is an annual report on nationwide drilling costs and the data can be adjusted to separate onshore and offshore drilling costs. In contrast, lease equipment costs, initial well production rates, and production decline rates are not readily available. Second, the use of "typical projects" implies an aggregation of data and a concomitant loss of fine detail. There will certainly be platforms that are more or less profitable than those in this analysis. This analysis strives to identify a set of projects that reasonably spans the diverse conditions within the industry and to evaluate the economic impacts of alternative pollution control approaches upon each of those projects.

5.2 CONSTRUCTION OF REGIONAL OFFSHORE OIL AND GAS PROJECTS

5.2.1 Overview

Four regions are analyzed in this study -- the Gulf of Mexico, the Pacific, the Atlantic, and Alaska. Model projects, ranging in size from a 1-well platform in the Gulf to a 70-well platform in the Pacific, were developed to span the diversity of size seen in the offshore oil and gas industry. Three categories of project were developed on the basis of production: oil-only, oil with casinghead gas (hereafter referred to as "oil/gas"), and gas-only. In all, 34 model projects were identified and included in this analysis; see Table 5-1. Appendix A contains a fuller description of the selection of the model projects.

5.2.2 Description of the Offshore Oil and Gas Projects

Parameter values for all projects are presented in Tables 5-2 through 5-7. All values are in 1986 dollars and are based on data for 1986 unless otherwise noted. Each parameter is defined below.

Project timing assumptions affect when capital investments are made and when production first begins. First production in the Gulf of Mexico begins one year after lease sale for small 1-well platforms (Table 5-2). Larger projects in the Gulf may take up to six years before production begins (see Gulf 58, Table 5-4). For the Pacific, first production occurs from 5 to 10 years after lease sale, depending upon project size (Table 5-4). No production is occurring in the Atlantic at this time; project lead-times of 5 to 7 years are based on information in recent studies (Table 5-5). For Alaska, production is assumed to occur six years after lease sale in Cook Inlet and up to 12 years after lease sale in the Arctic (Table 5-7). Appendix B contains a more complete description of timing assumptions.

Lease costs are based on 1986 OCS sales in the Gulf, on previous sales for the other regions, and other factors (see Table 5-8 and Appendix C). They range from $5,000 for the Atlantic project to $28,391,000 for the 58-well platform in the Gulf of Mexico. Geological and geophysical expenses are 110.5 percent of the leasing costs in the Lower 48 State region and 107.7 percent of leasing costs for Alaska projects (see Appendix D). The discovery efficiency is the ratio of productive exploratory wells to all exploratory wells drilled in that region. A value of 10 percent was chosen for the Atlantic since no productive wells have yet been discovered in this region. Discovery efficiencies for the Gulf, Pacific, and Alaska are 14 percent, 14 percent, and 27 percent, respectively (see Table 5-9 and Appendix C).

Well costs for exploratory and delineation wells are based on dry hole costs, since even if they are discovery wells, they are not turned into producers. These well costs are based on data in the 1986 Joint Association Survey on Drilling Costs for the number of wells, type of well, footage drilled, and costs for each state and Federal region with offshore activity (API 1987a; see Table 5-10 and Appendix D). The average cost for an offshore

TABLE 5-1

DISTRIBUTION OF OIL, OIL/GAS, AND GAS PRODUCING PLATFORMS BY REGION AND SIZE

REGION AND WELLSLOT SIZE	PRODUCTION TYPE OIL	OIL/GAS	GAS	COMMENTS
Gulf 1a[a]	Yes	Yes	Yes	
Gulf 1b[a]	Yes	Yes	Yes	
Gulf 4	Yes	Yes	Yes	
Gulf 6	Yes	Yes	Yes	
Gulf 12	Yes	Yes	Yes	
Gulf 24	Yes	Yes	Yes	
Gulf 40	Yes	Yes	No	No gas-only platforms among large platforms.
Gulf 58	Yes	Yes	No	No gas-only platforms among large platforms.
Atlantic 24	No	Yes	Yes	
Pacific 16	No	Yes	Yes	
Pacific 40	No	Yes	No	No gas-only platforms among large platforms.
Pacific 70	No	Yes	No	No gas-only platforms among large platforms.
Cook Inlet 12/24	No	Yes	Yes[b]	
Beaufort Sea 48				
- Gravel island	Yes	No	No	No infrastructure for gas delivery.
- Platform	Yes	No	No	No infrastructure for gas delivery.
Norton Basin 34	Yes	No	No	No infrastructure for gas delivery.
Navarin 48	Yes	No	No	No infrastructure for gas delivery.

Source: ERG model project configurations based on typical projects reported in the Department of the Interior Mineral Management Service platform inspection system and the literature.

[a]The Gulf 1a shares production equipment with three other single-well stuctures while the Gulf 1b has its own production equipment.

[b]The gas-only case is modeled as 12 wells.

Gulf_dsc.wk1

TABLE 5-2
BASELINE PARAMETERS FOR GULF OF MEXICO PROJECTS IN STATE WATERS

	Gulf 1a			Gulf 1b		
Parameter	oil	oil/gas	gas	oil	oil/gas	gas
Timing						
lease to exp.	0	0	0	0	0	0
exp. to del.	0	0	0	0	0	0
del. to dev.	0	0	0	0	0	0
dev. to op	1	1	1	1	1	1
Total-yrs to op.	1	1	1	1	1	1
Exploration						
Lease Bid ($000)	$586	$586	$586	$586	$586	$586
G & G expenses	110.5%	110.5%	110.5%	110.5%	110.5%	110.5%
Discovery eff.	14%	14%	14%	14%	14%	14%
Well cost ($000)	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355
Platform/disc.	4.3	4.3	4.3	4.3	4.3	4.3
Delineation						
Number of wells	0	0	0	0	0	0
Well cost ($000)	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355
Development						
Lease Eq. ($000)	$0	$0	$0	$1,166	$1,166	$1,166
Well cost ($000)	$4,906	$4,906	$6,302	$4,906	$4,906	$6,302
Number of wells	1	1	1	1	1	1
Wells/yr installed	1	1	1	1	1	1
Production						
oil (bopd)	500	500	-	500	500	-
gas (MMcf/day)	-	0.835	4.000	-	0.835	4.000
Yrs. at Peak Prod.	2	2	4	2	2	4
Prod. Decline rate	15%	15%	15%	15%	15%	15%
Annual O & M ($000)	$372	$372	$372	$200	$200	$200
Financial						
oil ($/bbl)	$23.82	$23.82	-	$23.82	$23.82	-
gas ($/Mcf)	-	$2.57	$2.57	-	$2.57	$2.57
Corporate Tax Rate	34%	34%	34%	34%	34%	34%
Royalty	22%	22%	22%	22%	22%	22%
Severance - oil	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%
Severance - gas	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%

Note: 1986 dollars.
Source: ERG estimates.

Gulf_dsc.wk1

TABLE 5-3
BASELINE PARAMETERS FOR GULF OF MEXICO PROJECTS IN STATE WATERS (cont.)

	Gulf 4			Gulf 6			Gulf 12		
Parameter	oil	oil/gas	gas	oil	oil/gas	gas	oil	oil/gas	gas
Timing									
lease to exp.	0	0	0	0	0	0	0	0	0
exp. to del.	0	0	0	0	0	0	1	1	1
del. to dev.	1	1	1	1	1	1	0	0	0
dev. to op	1	1	1	1	1	1	2	2	2
Total-yrs to op.	2	2	2	2	2	2	3	3	3
Exploration									
Lease Bid ($000)	$2,271	$2,271	$2,271	$3,407	$3,407	$3,407	$5,678	$5,678	$5,678
G & G expenses	110.5%	110.5%	110.5%	110.5%	110.5%	110.5%	110.5%	110.5%	110.5%
Discovery eff.	14%	14%	14%	14%	14%	14%	14%	14%	14%
Well cost ($000)	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355
Platform/disc.	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Delineation									
Number of wells	0	0	0	1	1	1	2	2	2
Well cost ($000)	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355
Development									
Lease Eq. ($000)	$4,664	$4,664	$4,664	$6,996	$6,996	$6,996	$11,660	$11,660	$11,660
Well cost ($000)	$4,906	$4,906	$6,302	$4,906	$4,906	$6,302	$4,906	$4,906	$6,302
Number of wells	4	4	4	6	6	6	10	10	10
Wells/yr installed	4	4	4	6	6	6	6	6	6
Production									
oil (bopd)	500	500	-	500	500	-	500	500	-
gas (MMcf/day)	-	0.835	4.000	-	0.835	4.000	-	0.835	4.000
Yrs. at Peak Prod.	2	2	4	2	2	4	2	2	4
Prod. Decline rate	15%	15%	15%	15%	15%	15%	15%	15%	15%
Annual O & M ($000)	$689	$689	$689	$910	$910	$910	$2,312	$2,312	$2,312
Financial									
oil ($/bbl)	$23.82	$23.82	-	$23.82	$23.82	-	$23.82	$23.82	-
gas ($/Mcf)	-	$2.57	$2.57	-	$2.57	$2.57	-	$2.57	$2.57
Corporate Tax Rate	34%	34%	34%	34%	34%	34%	34%	34%	34%
Royalty	22%	22%	22%	22%	22%	22%	22%	22%	22%
Severance - oil	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%
Severance - gas	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%	6.19%

Note: 1986 dollars.
Source: ERG estimates.

gulf_dsc.wk1

TABLE 5-4
BASELINE PARAMETERS FOR GULF OF MEXICO PROJECTS IN FEDERAL WATERS

	Gulf 24			Gulf 40		Gulf 58	
Parameter	oil	oil/gas	gas	oil	oil/gas	oil	oil/gas
Timing							
lease to exp.	0	0	0	0	0	0	0
exp. to del.	1	1	1	1	1	2	2
del. to dev.	0	0	0	0	0	2	2
dev. to op	2	2	3	2	2	2	2
Total-yrs to op.	3	3	4	3	3	6	6
Exploration							
Lease Bid ($000)	$10,221	$10,221	$10,221	$18,170	$18,170	$28,391	$28,391
G & G expenses	110.5%	110.5%	110.5%	110.5%	110.5%	110.5%	110.5%
Discovery eff.	14%	14%	14%	14%	14%	14%	14%
Well cost ($000)	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355
Platform/disc.	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Delineation							
Number of wells	2	2	2	2	2	2	2
Well cost ($000)	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355	$4,355
Development							
Lease Eq. ($000)	$20,988	$20,988	$20,988	$37,312	$37,312	$58,300	$58,300
Well cost ($000)	$4,906	$4,906	$6,302	$4,906	$4,906	$4,906	$4,906
Number of wells	18	18	18	32	32	50	50
Wells/yr installed	12	12	12	12	12	12	12
Production							
oil (bopd)	500	500	-	500	500	500	500
gas (MMcf/day)	-	0.835	4.000	-	0.835	-	0.835
Yrs. at Peak Prod.	2	2	4	2	2	2	2
Prod. Decline rate	15%	15%	15%	15%	15%	15%	15%
Annual O & M ($000)	$3,311	$3,311	$3,311	$4,688	$4,688	$6,471	$6,471
Financial							
oil ($/bbl)	$23.82	$23.82	-	$23.82	$23.82	$23.82	$23.82
gas ($/Mcf)	-	$2.57	$2.57	-	$2.57	-	$2.57
Corporate Tax Rate	34%	34%	34%	34%	34%	34%	34%
Royalty	17%	17%	17%	17%	17%	17%	17%
Severance - oil	-	-	-	-	-	-	-
Severance - gas	-	-	-	-	-	-	-

Note: 1986 dollars.
Source: ERG estimates.

pac_dsc.wk1

TABLE 5-5
BASELINE PARAMETERS FOR PACIFIC PROJECTS

	Pacific 16		Pacific 40	Pacific 70
Parameter	oil/gas	gas	oil/gas	oil/gas
Timing				
lease to exp.	1	1	1	1
exp. to del.	1	1	2	2
del. to dev.	1	2	3	5
dev. to op	2	2	2	2
Total-yrs to op.	5	6	8	10
Exploration				
Lease Bid ($000)	$2,236	$2,236	$5,272	$9,585
G & G expenses	110.5%	110.5%	110.5%	110.5%
Discovery eff.	14%	14%	14%	14%
Well cost ($000)	$5,888	$5,888	$5,888	$5,888
Platform/disc.	2	2	2	2
Delineation				
Number of wells	2	2	2	2
Well cost ($000)	$5,888	$5,888	$5,888	$5,888
Development				
Lease Eq. ($000)	$16,324	$16,324	$38,478	$69,960
Well cost ($000)	$2,357	$5,157	$2,357	$2,357
Number of wells	14	14	33	60
Wells/yr installed	12	12	12	12
Production				
oil (bopd)	900	-	900	900
gas (MMcf/day)	0.478	5.000	0.478	0.478
Yrs. at Peak Prod.	2	4	2	2
Prod. Decline rate	33.0%	22.0%	33.0%	33.0%
Annual O & M ($000)	$4,008	$4,008	$6,872	$11,212
Financial				
oil ($/bbl)	$17.50	-	$17.50	$17.50
gas ($/Mcf)	$1.89	$1.89	$1.89	$1.89
Corporate Tax Rate	34%	34%	34%	34%
Royalty	17%	17%	22%	17%
Severance - oil	-	-	-	-
Severance - gas	-	-	-	-

Note: 1986 dollars.
Source: ERG estimates.

atl_dsc

TABLE 5-6
BASELINE PARAMETERS FOR ATLANTIC PROJECTS

Parameter	Atlantic 24 oil	Atlantic 24 gas
Timing		
lease to exp.	1	1
exp. to del.	2	2
del. to dev.	2	2
dev. to op	2	4
Total-yrs to op.	7	9
Exploration		
Lease Bid ($000)	$5	$5
G & G expenses	110.5%	110.5%
Discovery eff.	10%	10%
Well cost ($000)	$27,792	$27,792
Platform/disc.	1	1
Delineation		
Number of wells	2	2
Well cost ($000)	$27,792	$27,792
Development		
Lease Eq. ($000)	$23,320	$23,320
Well cost ($000)	$7,226	$7,226
Number of wells	20	20
Wells/yr installed	12	12
Production		
oil (bopd)	1,000	-
gas (MMcf/day)	-	7.5
Yrs. at Peak Prod.	2	8
Prod. Decline rate	15%	15%
Annual O & M ($000)	$5,009	$5,009
Financial		
oil ($/bbl)	$17.50	-
gas ($/Mcf)	-	$1.89
Corporate Tax Rate	34%	34%
Royalty	17%	17%
Severance - oil	-	-
Severance - gas	-	-

Note: 1986 dollars.
Source: ERG estimates.

ak_dsc

TABLE 5-7
BASELINE PARAMETERS FOR ALASKA PROJECTS

Parameter	Cook Inlet 24 oil/gas	Cook Inlet 12 gas	Beaufort Gravel oil	Beaufort Platform oil	Navarin Platform oil	Norton Platform oil
Timing						
lease to exp.	1	1	2	2	2	2
exp. to del.	1	1	3	3	3	2
del. to dev.	2	2	3	4	3	2
dev. to op	2	2	3	3	3	3
Total-yrs to op.	6	6	11	12	11	9
Exploration						
Lease Bid ($000)	$56	$56	$7,097	$7,097	$7,097	$4,968
G & G expenses	107.7%	107.7%	107.7%	107.7%	107.7%	107.7%
Discovery eff.	27%	27%	27%	27%	27%	27%
Well cost ($000)	$13,851	$13,851	$13,851	$13,851	$13,851	$13,851
Platform/disc.	1	1	1	1	1	1
Delineation						
Number of wells	2	2	3	3	3	3
Well cost ($000)	$13,851	$13,851	$13,851	$13,851	$13,851	$13,851
Development						
Lease Eq. ($000)	$100,000	$50,000	$270,000	$303,700	$524,400	$174,500
Well cost ($000)	$5,612	$3,188	$5,612	$5,612	$5,612	$5,612
Number of wells	20	10	40	40	40	28
Wells/yr installed	12	6	12	12	12	12
Production						
oil (bopd)	1,960	-	1,960	1,960	1,960	1,960
gas (MMcf/day)	0.9	15.00	-	-	-	-
Yrs. at Peak Prod.	2	16	2	2	2	2
Prod. Decline rate	10%	15%	10%	10%	10%	10%
Annual O & M	$5,230	$3,677	$18,100	$25,300	$19,900	$19,000
Financial						
oil ($/bbl)	$19.58	-	$14.80	$14.80	$14.80	$14.80
gas ($/Mcf)	$2.11	$2.11	-	-	-	-
Corporate Tax Rate	34%	34%	34%	34%	34%	34%
Royalty	22%	22%	22%	17%	17%	17%
Severance - oil				-	-	-
Severance - gas				-	-	-

Note: 1986 dollars.
Source: ERG estimates.

$lease.wk1

TABLE 5-8
LEASE PRICES FOR MODEL PROJECTS

Region		Model Project	Number of Producing Wells	Production Ratio	Lease Price ($000)	Exploratory Wells/ Discovery Well	Platforms/ Discovery	Model Project Lease Price ($000)
Gulf		1	1	0.3	$1,318	7.41	4.3	$568
		4	4	1.0	$1,318	7.41	4.3	$2,271
		6	6	1.5	$1,318	7.41	4.3	$3,407
		12	10	2.5	$1,318	7.41	4.3	$5,678
		24	18	4.5	$1,318	7.41	4.3	$10,221
		40	32	8.0	$1,318	7.41	4.3	$18,170
		58	50	12.5	$1,318	7.41	4.3	$28,391
Pacific		16	14	0.4	$1,423	7.41	2.0	$2,236
		40	33	1.0	$1,423	7.41	2.0	$5,272
		70	60	1.8	$1,423	7.41	2.0	$9,585
Atlantic		24	20	1.0	$0.475	10.00	1.0	$5
Alaska	Cook Inlet		20	1.0	$15	3.70	1.0	$56
	Cook Inlet-gas		10	1.0	$15	3.70	1.0	$56
	Beaufort-gravel		40	1.0	$1,918	3.70	1.0	$7,097
	Beaufort-plat.		40	1.0	$1,918	3.70	1.0	$7,097
	Norton		28	0.7	$1,918	3.70	1.0	$4,968
	Navarin		40	1.0	$1,918	3.70	1.0	$7,097

Note: 1986 dollars.
Source: ERG estimates.

disc_eff.wk1

TABLE 5-9
TOTAL EXPLORATORY OFFSHORE WELLS DRILLED TO JANUARY 1, 1985

Region	Oil	Gas	Dry	Total	Discovery Efficiency	Number of Exploratory Wells Per Discovery
Alaska	20	7	73	100	0.27	3.70
California	44	10	294	348	0.16	
Oregon	0	0	8	8	0.00	
Washington	0	0	6	6	0.00	
Federal Pacific	0	0	38	38	0.00	
TOTAL PACIFIC	44	10	346	400	0.14	7.41
Alabama	0	2	0	2	1.00	
Florida	0	0	24	24	0.00	
Louisiana	267	349	3999	4615	0.13	
Texas	45	273	1732	2050	0.16	
Federal-GOM	0	0	241	241	0.00	
TOTAL GULF OF MEXICO	312	624	5996	6932	0.14	7.41
ATLANTIC	0	0	36	36	0.00	na
GRAND TOTAL	376	641	6451	7468	0.14	7.34

Note: Well count includes wells in both Federal and State waters.
na = not applicable

Source: API 1988; MMS 1986b.

wellnew.wk1

TABLE 5-10 19-Jan-90
AVERAGE WELL DEPTHS AND COSTS - 1986 DATA*

Region	Oil Depth (ft)	Oil Cost per foot ($/ft)	Oil Cost per well ($)	Gas Depth (ft)	Gas Cost per foot ($/ft)	Gas Cost per well ($)	Dry Depth (ft)	Dry Cost per foot ($/ft)	Dry Cost per well ($)	Total Depth (ft)	Total Cost per foot ($/ft)	Total Cost per well ($)
Alaska	10,868	$335.47	$3,645,773	7,721	$231.95	$1,790,891	9,662	$1,047.05	$10,116,095	10,440	$430.89	$4,498,524
California	6,887	$229.97	$1,583,662	6,477	$721.18	$4,671,091	ERR	ERR	ERR	6,870	$248.87	$1,709,680
Louisiana	9,678	$274.13	$2,653,026	10,848	$337.29	$3,658,899	10,888	$302.53	$3,293,896	10,394	$299.71	$3,115,359
Texas	8,395	$308.40	$2,588,998	11,995	$486.59	$5,836,414	10,880	$376.95	$4,101,249	11,321	$433.69	$4,909,698
Fed-Alaska	ERR	ERR	ERR	ERR	ERR	ERR	8,868	$1,842.62	$16,340,956	8,868	$1,842.62	$16,340,956
Fed - Gulf	11,583	$716.27	$8,296,256	9,873	$631.17	$6,231,854	12,301	$641.10	$7,886,401	11,823	$661.58	$7,821,666
Fed-Pacific	6,777	$527.33	$3,573,495	ERR	ERR	ERR	7,063	$833.59	$5,887,793	6,896	$658.03	$4,537,786
AK-TOTAL	10,868	$335.47	$3,645,773	7,721	$231.95	$1,790,891	9,186	$1,507.90	$13,851,011	10,145	$662.27	$6,718,980
PAC-TOTAL	6,872	$267.98	$1,841,604	6,477	$721.18	$4,671,091	7,063	$833.59	$5,887,793	6,875	$329.61	$2,266,029
GULF-TOTAL	9,885	$340.37	$3,364,631	11,174	$408.05	$4,559,374	11,171	$389.81	$4,354,555	10,750	$379.62	$4,081,100
ALL OFFSHORE	9,426	$331.64	$3,126,096	11,112	$409.22	$4,547,079	11,086	$406.70	$4,508,601	10,476	$382.27	$4,004,805
ATLANTIC		see discussion in text							$27,791,575			

* Current dollars.
Note: ERR denotes no wells drilled in that category in 1986.
Source: API 1987b.

well in 1986 is $4,004,805. This value is the average of all wells, both dry and productive.

The number of platforms per discovery well is based on the number of discovery wells and platforms for the Gulf, on the number of platforms per field for the Pacific, and on engineering studies of projected activity in the Atlantic and Alaska (see Appendix C). Anywhere from 0 to 3 delineation wells are modeled for a project based on the size and location of that project (Appendix E).

Platform costs are included as part of the drilling costs in the JAS survey. These costs do not include lease equipment such as flow lines, flow tanks, separators, etc. A separate entry for lease equipment costs is made based on the size of the project and the 1986 API Survey on Oil and Gas Expenditures (API 198b); see Table 5-11. Alaska development costs are based on the Steelhead platform in Cook Inlet and on data in Oil and Gas Technologies for the Arctic and Deepwater (OTA 1985); see Table 5-12.

Well costs for development wells are based on the costs for productive wells and are based on the 1986 Joint Association Survey. These costs are adjusted by the discovery efficiency for development wells and distinctions are made between oil wells and gas wells (Table 5-13). Not all wellslots on a platform may be utilized by productive wells; the number of producing wells per platform ranges from 3/4 to 5/6 of the wellslots. Each well is assumed to take two months to drill; a single rig can therefore drill six wells per year. Platforms with more than 12 wellslots are assumed to accommodate two drilling rigs simultaneously. These platforms may therefore have development wells installed at a rate of 12 per year. A more complete discussion of development phase assumptions and data is located in Appendix F.

Initial production rates, years at peak production, and production decline rates interact to form the "production profile" of a well. Production profiles can vary widely by well, even among wells on the same platform. The production profiles used in this analysis are based on field data, the production profile used by MMS for recent EIS in the Gulf of Mexico, and engineering studies. Peak production rates and production decline rates are shown in Tables 5-14 and 5-15, respectively. Projects with oil production are assumed to stay at peak production for two years. Gas-only projects stay at peak production for four years (Gulf and Pacific), eight years (Atlantic), or 16 years (Cook Inlet, Alaska). Appendix G contains an expanded discussion of these parameters.

Equip.wk1

TABLE 5-11
LEASE EQUIPMENT COSTS - GULF, PACIFIC AND ATLANTIC

Region	Project	Number of Producing Wells	Lease Equipment Costs ($MM 1986)
Gulf	1b	1	$1.166
	4	4	$4.664
	6	6	$6.996
	12	10	$11.660
	24	18	$20.988
	48	32	$37.312
	58	50	$58.300
Pacific	16	14	$16.324
	40	33	$38.478
	70	60	$69.960
Atlantic	24	20	$23.320

Source: ERG estimates.

$_akcon.wk1

TABLE 5-12
LEASE EQUIPMENT COSTS FOR ALASKA PROJECTS

Project	Development Cost ($MM 1984)	Non-drilling Development Cost ($MM 1984)	Number of Islands/ Platforms	Cost per Platform ($MM 1984)	Cost per Platform ($MM 1986)	Producing Wells per Platform	Cost per Well ($MM 1986)
Beaufort platform	3,162	2,134.4	7	$304.9	$303.7	40	$7.59
Navarin Basin	5,460	3,685.5	7	$526.5	$524.4	40	$13.11
Norton Basin	1,038	700.7	4	$175.2	$174.5	28	$6.23
Beaufort Gravel*	800	540.0	2	$270.0	$270.0	40	$6.75
Cook Inlet oil*		200.0	2	$100.0	$100.0	20	$5.00
Cook Inlet gas*		200.0	4	$50.0	$50.0	10	$5.00

Notes: * Costs are in 1986 dollars.

1984 prices deflated by 0.4% based on implicit price deflators for gross national product for producers' durable equipment.

Sources: OTA 1985; OGJ 1986; Offshore 1986; Economic Report 1987.

dev_cost.wk1

TABLE 5-13
DEVELOPMENT WELL COST - 1986 DATA*

Region	Type of Production	Number of Development Wells Per Producing Well	Average Depth (ft)	Cost per foot ($/ft) Productive	Cost per foot ($/ft) Dry	Composite Cost per Development Well ($)
Gulf	oil, oil/gas	1.4	9,885	$340.37	$389.81	$4,905,866
	gas	1.4	11,174	$408.05	$389.81	$6,301,845
Pacific	oil, oil/gas	1.09	6,872	$267.98	$833.59	$2,357,117
	gas	1.09	6,477	$721.18	$833.59	$5,157,007
Alaska	oil, oil/gas	1.12	10,868	$335.47	$1,507.90	$5,612,431
	gas	1.12	7,721	$231.95	$1,507.90	$3,187,985
Atlantic	oil, oil/gas		see text for description			$7,225,810
	gas					

Note: Current dollars.
Source: ERG estimates, see Table D-2.

TABLE 5-14

PEAK OFFSHORE PER-WELL PRODUCTION RATES

REGION	PROJECT	OIL ONLY BOPD	OIL AND GAS BOPD	OIL AND GAS MCF/DAY	GAS-ONLY MCF/DAY
Gulf	1	500	500	835	4,000
	4	500	500	835	4,000
	6	500	500	835	4,000
	12	500	500	835	4,000
	24	500	500	835	4,000
	40	500	500	835	4,000
	58	500	500	835	4,000
Pacific	16	900	900	478	5,000
	40	900	900	478	--
	70	900	900	478	--
Alaska[a]					
Cook Inlet	12	--	--	--	15,000
	24	1,960	1,960	900	--
Beaufort Sea - Gravel	48	1,960	--	--	--
Beaufort Sea - Platform	48	1,960	--	--	
Norton	34	1,960	--	--	
Navarin	48	1,960	--	--	
Atlantic	24	1,000	1,000	7,500	

Source: ERG estimates.

[a]There is no infrastructure to transport produced gas from the Arctic scenarios.

TABLE 5-15

PRODUCTION DECLINE RATES

REGION	PROJECT	PRODUCTION DECLINE RATES (%) OIL-ONLY OIL/GAS	GAS-ONLY
Gulf	1	15	15
	4	15	15
	6	15	15
	12	15	15
	24	15	15
	40	15	15
	58	15	15
Pacific	16	33	22
	40	33	--
	70	33	--
Alaska	Cook Inlet	10	15
	Beaufort Sea - Gravel	10	--
	Beaufort Sea - Platform	10	--
	Norton Basin	10	--
	Navarin Basin	10	--
Atlantic	24	15	15

-- = Not applicable.

Source: ERG estimates.

<u>Operation and maintenance costs</u> (O&M) are based on the data in DOE 1987a, an annual survey performed by the DOE Energy Information Administration. The survey includes O&M costs for a 12-wellslot platform in 100 and 300 feet of water, as well as an 18-wellslot platform in 100, 300, and 600 feet of water in the Gulf of Mexico. A regression analysis was fit to the data using the model: cost = a + b(wellslots) + c(water depth). The estimates for a, b, and c are $1,286,123, $80,859 and $840, respectively. Labor costs and workover costs form substantial portions of the overall costs and these are not affected by water depth. For smaller platforms, the assumptions associated with the DOE survey costs are not appropriate. A separate methodology was used to derive costs for the Gulf 1, Gulf 4, and Gulf 6 model projects, see Appendix G. Table 5-16 summarizes the projected O&M costs for Gulf of Mexico projects.

The same equation and parameters are used to estimate O&M costs for the larger Gulf projects are used for the Pacific and Cook Inlet projects with the costs being adjusted for regional differences (Table 5-17). O&M costs for Arctic projects are based on scenarios in OTA 1985. The scenario O&M costs are divided among the number of platforms/island in the scenario and then inflated to 1986 dollars (Table 5-18). Further information on O&M costs and their derivation is located in Appendix G.

<u>Wellhead prices</u> for oil and gas (also known as "first purchase price") are an integral part of the parameter inputs for the economic impact analysis. Like other parameters in the analysis, there is a range of uncertainty around the point estimate used in the computer simulations. Table 5-19 lists the annual average wellhead price for oil from 1980 to November 1987. The price for a barrel of oil nearly doubles from $12.51 in 1979 to $21.59 in 1980 and rises by an additional 50 percent to 31.77 in 1981. The price then declines for the next few years and collapses in 1986 to $12.66 per barrel. Prices presently vary around the high teens for a barrel of oil. Higher oil prices in future years are projected by two studies. The <u>Annual Energy Outlook 1986</u> presented by the Energy Information Administration projects oil prices between $26.80 and $41.50 (in 1986 dollars per barrel) by the year 2000 (DOE, 1987b). The study "Lower Oil Prices: Mapping the Impact," by Harvard University's Energy and Environmental Policy Center notes that, after adjusting for inflation and currency movements, oil prices paid by most industrial companies is at a 15-year low (Harvard, 1988). This study also projects higher oil prices in the future.

The regulations cover the 15-year period from 1986 through 2000. Oil prices can fluctuate widely within a 15-year period. The analysis should

gulf_o&m.wk1

TABLE 5-16
OPERATING COSTS FOR GULF OF MEXICO PLATFORMS

Project	Number of Wellslots	Water Depth (ft)	Cost ($1986)
Gulf 1a	1	33	$372,213
Gulf 1b	1	33	$199,882
Gulf 4	4	33	$689,324
Gulf 6	6	33	$910,137
Gulf 12	12	66	$2,311,861
Gulf 24	24	100	$3,310,725
Gulf 40	40	200	$4,688,455
Gulf 58	58	590	$6,471,456

Source: ERG estimates.

gulf_o&m.wk1

TABLE 5-17
OPERATING COSTS FOR PACIFIC, ATLANTIC, AND COOK INLET PLATFORMS

Project	Number of Wellslots	Water Depth (ft)	Cost ($1986)	Regional Cost Factor	Estimated Cost ($1986)
Pacific 16	16	300	$2,831,820	1.44	$4,077,821
Pacific 40	40	300	$4,772,439	1.44	$6,872,312
Pacific 70	70	1000	$7,786,100	1.44	$11,211,984
Atlantic 24	24	300	$3,478,693	1.44	$5,009,318
Cook Inlet 24	24	50	$3,268,733	1.60	$5,229,973
Cook Inlet 12	12	50	$2,298,424	1.60	$3,677,478

Source: ERG estimates.

ak_o&m.wk1

TABLE 5-18
OPERATION AND MAINTENANCE COSTS FOR ALASKA PROJECTS

Project	Operation and Maintenance Cost ($MM 1984)	Number of Islands/ Platforms	Cost per Platform ($MM 1984)	Cost per Platform ($MM 1986)
Beaufort platform	$168.0	7	$24.0	$25.3
Navarin Basin	$132.0	7	$18.9	$19.9
Norton Basin	$72.0	4	$18.0	$19.0
Beaufort Gravel	$120.0	7	$17.1	$18.1

Note: 1984 prices inflated by 5.56% based on change in consumer price index.

Sources: OTA 1985; Economic Report 1988.

TABLE 5-19

CRUDE OIL PRICES, 1980 TO NOVEMBER 1987

YEAR MONTH	DOMESTIC FIRST PURCHASE PRICES*
1980 Average	21.59
1981 Average	31.77
1982 Average	28.52
1983 Average	26.19
1984 Average	25.88
1985 Average	24.09
1986	
January	23.12
February	17.65
March	12.62
April	10.68
May	10.75
June	10.68
July	9.25
August	9.77
September	11.09
October	11.00
November	11.05
December	11.73
1986 Average	12.51
1987	
January	13.89
February	14.50
March	14.53
April	14.95
May	15.29
June	15.95
July	16.88
August	17.06
September	16.25
October	15.95
November	15.45

*Current dollars.

Source: DOE 1988.

incorporate an oil price representative of the entire 15-year period and not reflect the lower range of the oil price cycle. The projected number of wells is based on an oil price of $21.00 per barrel (1987 dollars, see Section Four), and the same price is used within the economic analysis. Oil prices are regionalized by taking the ratio of the regional wellhead price to the national price for 1985 data (see Table 5-20). For the past five years, gas prices per Mcf have averaged 10.8 percent of the price of a barrel of oil (Table 5-21), and this factor is used to estimate regional wellhead prices for gas.

The Tax Reform Act of 1986 (Public Law 99-514) set the corporate tax rate at 34 percent, assuming that the company has at least $100,000 of net income without the model project. Royalty rates of 22 and 17 percent are used for state and Federal leases, respectively. Severance tax rates are based on state severance tax rates within each region. For example, the severance tax structure for Alaska consists of nominal rates that are then adjusted by a formula called the Economic Limit Factor. Appendix I contains the financial assumptions and data used in this analysis.

5.2.3 Results of Base Case Simulations - NSPS

For new sources, the model projects encompass the entire lifespan of the oil and gas project. Costs begin with the purchase of the lease and end after 30 years of production or when the project becomes uneconomical and shuts down. The costs and assumptions described in Section 5.2.2 are used with the NSPS projects.

Tables 5-22 and 5-23 summarize the financial performance of each NSPS project, including the internal rate of return (IRR) for each project. The real cost of capital used in this study is 8 percent. In the Gulf, the Gulf 1b project has the lowest IRR. For the gas-only cases, the IRR is 4.7 percent while the IRR for the oil-and-gas case is 9.5 percent. IRRs for the other Gulf projects range from 12.8 percent to 27.3 percent. The Gulf 1b gas-only case, then, has an IRR less than the cost of capital used in this analysis. Economic impacts are viewed as the amount of change caused by the cost of additional pollution control relative to the baseline value. With a small baseline value, we would expect the Gulf 1b projects to be the most sensitive to any change in the IRR.

wellhead.wk1 23-Jan-90

TABLE 5-20
WELLHEAD PRICES AND REGIONAL RELATIONSHIPS - 1985 DATA

Region	1985 Wellhead Price ($/bbl)	Ratio	Estimated Oil Price ($/bbl) 1986-2000	Estimated Gas Price ($/Mcf) 1986-2000
National	$24.09	1.00	$21.00	$2.27
Offshore Gulf	$27.33	1.13	$23.82	$2.57
Offshore CA	$20.08	0.83	$17.50	$1.89
AK North Slope	$16.98	0.70	$14.80	$1.60
AK other	$22.46	0.93	$19.58	$2.11

Source: DOE 1986.

oil_gas.wk1

TABLE 5-21
RELATIONSHIP OF DOMESTIC OIL AND GAS PRICES - 1982-1987

Year	Oil Price ($/bbl)	Gas Price ($/Mcf)	Ratio
1982	$28.52	$2.46	8.6%
1983	$26.19	$2.59	9.9%
1984	$25.88	$2.66	10.3%
1985	$24.09	$2.51	10.4%
1986	$12.51	$1.94	15.5%
Aug. 1987	$17.06	$1.71	10.0%
Average Ratio			10.8%

Note: Current dollars.
Source: DOE 1987, DOE 1988.

TABLE 5-22

BASELINE FINANCIAL SUMMARY STATISTICS
NSPS PROJECTS - PROJECTS WITH OIL PRODUCTION

Region	Project	PV of Total Production (Bbls-of-oil equivalent)	Corporate Cost Per BOE	Production Cost Per BOE	Net Present Value ($1000)	Internal Rate of Return	Years Of Production
Oil and Gas Production							
Gulf of Mexico	Gulf 1b	1,159,301	$21.16	$13.71	$654	9.5%	20
	Gulf 4	4,301,632	$18.09	$8.98	$15,649	21.4%	21
	Gulf 6	6,452,448	$17.71	$8.40	$25,909	23.1%	21
	Gulf 12	9,611,069	$18.23	$8.95	$33,610	20.1%	19
	Gulf 24	17,470,722	$16.26	$8.13	$95,532	27.3%	21
	Gulf 40	29,889,385	$16.04	$7.74	$169,856	25.2%	23
	Gulf 58	35,194,925	$16.53	$7.90	$182,742	20.7%	25
Atlantic	Atlantic 24	25,801,198	$19.05	$16.52	($66,121)	2.6%	21
Pacific	Pacific 16	11,449,953	$12.96	$7.19	$45,337	39.4%	9
	Pacific 40	20,252,704	$12.89	$6.05	$81,686	33.8%	10
	Pacific 70	29,277,100	$12.38	$5.94	$132,919	29.5%	12
Alaska	Cook Inlet	61,707,003	$13.22	$4.18	$357,708	39.0%	30
Projects with Oil-only Production							
Alaska	B. Gravel Is.	73,172,498	$12.19	$5.53	$191,157	18.4%	30
	B. Platform	67,592,103	$11.50	$6.33	$233,074	20.5%	28
	Navarin	73,172,498	$12.41	$7.47	$175,208	15.2%	30
	Norton	61,740,561	$11.22	$6.09	$220,856	24.1%	27

Source: ERG estimates. 23-Jan-90

TABLE 5-23

BASELINE FINANCIAL SUMMARY STATISTICS
NSPS PROJECTS - PROJECTS WITH GAS-ONLY PRODUCTION

Region	Project	PV of Total Production (Bbls-of-oil equivalent)	Corporate Cost Per BOE	Production Cost Per BOE	Net Present Value ($1000)	Internal Rate of Return	Years Of Production
Gulf of Mexico	Gulf 1b	1,534,266	$15.73	$11.27	($1,706)	4.7%	20
	Gulf 4	5,694,403	$13.40	$7.69	$6,885	12.8%	21
	Gulf 6	8,541,605	$13.12	$7.25	$12,763	14.0%	21
	Gulf 12	12,713,538	$13.52	$7.68	$13,767	12.1%	19
	Gulf 24	21,412,488	$12.29	$7.16	$49,389	16.6%	21
Atlantic	Atlantic 24	38,935,162	$12.28	$10.52	($59,921)	4.1%	25
Pacific	Pacific 16	15,493,937	$10.08	$7.03	$10,241	11.8%	13
Alaska	Cook Inlet 12	52,694,332	$8.41	$2.96	$188,211	31.6%	29

Source: ERG estimates. 23-Jan-90

The Pacific projects have IRRs ranging from 11.8 percent to 39.4 percent. Alaska projects have IRRs ranging from 15.2 percent to 39.0 percent.

The Atlantic projects also have IRRs less than the cost of capital used in this study. The IRRs for the Atlantic projects range from 2.6 percent to 4.1 percent. As with the Gulf 1b projects, the IRRs for the Atlantic projects may be sensitive to additional pollution control costs.

Net present value: Again, the Gulf 1b model project is distinguished by its low values. The NPV for the Gulf 1b gas-only case is negative $1,706,000. (The NPV is negative because the IRR is below the cost of capital). The NPV for the oil-and-gas case is $654,000. The other scenarios have NPVs anywhere from 3 to 90 times larger. This implies that any change in the NPV of a project caused by the costs of additional pollution control will be most evident in the Gulf 1b cases.

Production and corporate costs per BOE (barrels-of-oil-equivalent): The difference in the costs is that corporate costs include cash outflows such as income and severance taxes that involve no social resources. If the corporate cost is less than the wellhead price, then the amount of money received for a barrel of oil exceeds the amount of money expended to recover that barrel, i.e., the project is considered viable. Wellhead prices exceed corporate costs for all projects except the Gulf 1b gas-only case and those in the Atlantic. This is consistent with the negative net present values and low IRRs seen for these projects.

Present value equivalent of production: The range in project size is evident -- production ranges from 1,159,301 BOE for the Gulf 1b oil-and-gas case to 73,172,498 BOE for projects in the Beaufort Sea and Navarin Basin of Alaska. This parameter is included in the analysis to see whether additional costs of pollution control will curtail production once a project is undertaken.

5.2.4 Results of Base Case Simulations - BAT Projects

BAT regulations are applied to existing projects. For drilling wastes, BAT wells are limited to wells drilled to complete a drilling program on existing platforms. These projects are in the beginning of their productive lifespan and so are included in the study of the impacts of the NSPS regulations. For production wastes, additional pollution control costs would be incurred by projects anywhere within their productive lifespan. For BAT regulations on produced water, we evaluated the impacts on projects mid-way through their economic life.

BAT model projects were derived from the NSPS models. First, oil prices were changed to reflect 1987 prices in co-ordination with the March 1988 version of the MMS Platform Inspection System, Complex/Structure data base from which the counts of producing platforms in the Federal Gulf of Mexico were obtained (Appendix H). Oil prices of $17.54/bbl and $11.82/bbl and gas prices of $1.89/Mcf and $1.28/Mcf were used for the Gulf and Pacific, respectively (DOE, 1989). These runs provided baseline economic lifetimes and production profiles.

Second, all pre-production costs were removed from the models, initial production was set to that at the mid-life of the well, and years at peak production was set a one year. O&M costs are the same for BAT and NSPS projects. These computer runs provided us with the baseline BAT financial summary statistics which are given in Table 5-24 and 5-25.

Only projects in the Gulf and the Pacific are included in the analysis of BAT regulations. This is because there is no existing production in the Atlantic. Current production from Cook Inlet, Alaska is in the coastal subcategory, not the offshore category. The only existing offshore project in Alaska is the Endicott field on gravel islands in the Beaufort Sea and this project is required to inject its produced water as a condition of its permit from the State. There are a few oil-only projects in the Gulf and so economic models were developed for them.

The years of production range from 4 to 11 years while the present value of production ranges from 246,886 BOE for the Gulf 1a to 21,698,858 BOE for the large Pacific 70 project. Net present values range from $939,000 to $101,673. The net present value for the Gulf 1 projects is positive since it no longer has to recover pre-production costs. (The pre-production costs are sunk costs and are not considered when the operator must decide whether the project would recover the costs of additional pollution control requirements.) Since there are no pre-production costs, the internal rate of return is a meaningless measure for BAT projects.

TABLE 5-24

BASELINE FINANCIAL SUMMARY STATISTICS
BAT PROJECTS - PROJECTS WITH OIL PRODUCTION

Region	Project	PV of Total Production (Bbls-of-oil equivalent)	Corporate Cost per BOE	Production Cost per BOE	Net Present Value ($1000)	Years of Production
Oil and Gas Production						
Gulf of Mexico	Gulf 1a	315,596	$12.32	$6.14	$1,159	7
	Gulf 1b	246,886	$11.61	$5.06	$1,083	9
	Gulf 4	914,626	$11.38	$4.71	$4,224	9
	Gulf 6	1,410,228	$11.13	$4.33	$6,864	10
	Gulf 12	2,882,620	$11.58	$5.01	$12,735	9
	Gulf 24	4,482,198	$10.50	$4.96	$24,605	10
	Gulf 40	7,594,632	$10.14	$4.41	$44,451	11
	Gulf 58	11,473,877	$9.89	$4.03	$70,044	11
Pacific	Pacific 16	3,925,097	$7.40	$3.38	$15,815	4
	Pacific 40	9,984,146	$7.36	$2.75	$40,642	5
	Pacific 70	21,698,858	$6.75	$2.39	$101,673	6
Oil Production						
Gulf of Mexico	Gulf 1a	248,611	$13.64	$6.92	$970	6
	Gulf 1b	200,293	$12.85	$5.73	$939	8
	Gulf 4	764,960	$12.78	$5.63	$3,638	9
	Gulf 6	1,146,599	$12.34	$4.96	$5,960	9
	Gulf 12	2,322,310	$12.85	$5.72	$10,903	8
	Gulf 24	3,644,365	$11.68	$5.68	$21,365	9
	Gulf 40	6,212,018	$11.27	$5.06	$38,926	10
	Gulf 58	9,582,253	$11.11	$4.82	$61,581	11

Source: ERG estimates. 23-Jan-90 base_b.wk1

TABLE 5-25

BASELINE FINANCIAL SUMMARY STATISTICS
BAT PROJECTS - GAS-ONLY PRODUCTION

Region	Project	PV of Total Production (Bbls-of-oil equivalent)	Corporate Cost per BOE	Production Cost per BOE	Net Present Value ($1000)	Years of Production
Gulf of Mexico	Gulf 1a	476,918	$8.23	$4.06	$1,194	7
	Gulf 1b	370,486	$7.78	$3.37	$1,097	9
	Gulf 4	1,383,149	$7.61	$3.11	$4,330	9
	Gulf 6	1,980,296	$7.59	$3.08	$6,237	10
	Gulf 12	4,445,835	$7.70	$3.25	$13,520	9
	Gulf 24	6,854,869	$6.99	$3.24	$25,653	10
Pacific	Pacific 16	8,880,736	$4.84	$2.35	$21,602	7

Note: There are no gas-only Gulf 40 or Gulf 58 projects at present. base_b.wk1
Source: ERG estimates. 23-Jan-90

5.3 REFERENCES

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SECTION SIX

COSTS OF COMPLIANCE

The regulatory options for the disposal of drilling and production wastes are discussed in Section One. The costs of compliance were developed by the Industrial Technology Division (ITD), U.S. Environmental Protection Agency and are discussed in more detail in the Development Document for this proposal.

6.1 DRILLING FLUIDS AND DRILL CUTTINGS

In this section, incremental costs of increased pollution control are calculated using current permit requirements as the baseline. The annual cost associated with each option is a function of the number of wells drilled per year, volume of wastes generated per well, toxicity test and static sheen failure rates, and other assumptions. Section 6.1.1 summarizes assumptions associated with the costing efforts while Section 6.1.2 reviews current permit requirements. Section 6.1.3 estimates costs of compliance.

6.1.1 Assumptions

Number of Wells Per Year: The annual cost of compliance is based on the estimated average of 978 or 759 wells drilled per year. These are the average annual number of projected wells drilled between 1986 and 2000 based on an average oil price of $21.00 per barrel (constant dollars). The first estimate, 978, is for unrestricted development while the second estimate, 759, is for restricted development; see Section Four for details. Other estimates for the annual cost of compliance are made for alternative assumptions for oil price and development.

Model Well Characteristics: Model well characteristics were developed by ITD relying on the Joint Association Survey on Drilling Costs. The model well characteristics were used to estimate compliance costs and underlying assumptions for the regulatory options. Separate model wells were developed for each of the four geographic regions. Each model well has three segments:

- 0 to 8,000 ft
- 8,000 to 10,000 ft: where 22 percent of the wells encounter a stuck pipe problem
- 10,000 to 14,000 ft: only 30.8 percent of the wells go to depths beyond 10,000 ft. An oil-based mud is assumed to be used in this segment.

Table 6-1 summarizes the regional volumes of drilling fluids and drill cuttings in the 0 to 10,000-ft interval. The volumes differ because the average well depth differs by region.

Water-Based and Oil-Based Drilling Fluid Assumptions: The proposed regulation and the alternative options presented here do not prohibit the use of oil-based drilling fluids; they do prohibit the discharge of such fluids. Water-based fluids are assumed to be used for the 0 to 10,000-ft depth. For wells that continue to 14,000 ft, an oil-based fluid is assumed to be used for the 10,000 to 14,000-ft interval. Spent oil-based fluid from this segment of the drilling operations must be reused or barged to shore for disposal under BPT regulations.

Lubricity Assumptions: Lubricity agents are assumed to be added only to the water-based fluids used for the 0 to 10,000-ft well-depth interval. Wells deeper than 10,000 ft are assumed to use an oil-based fluid and so require no added oil for lubricity. No lubricity agent is needed between the 0 and 10,000-ft depth for 88 percent of the wells. Of the 12 percent of the wells that do use a lubricity agent, it is assumed that 68 percent would have used mineral oil while the remaining 32 percent would have used diesel. To comply with the no-discharge-of-diesel requirement and to avoid barging, however, the 32 percent are now assumed to substitute mineral oil for diesel. This assumption results in 88 percent of the wells using no lubricity agent, 8.16 percent using mineral oil without a change of plans, and 3.84 percent having to change from diesel to mineral for lubricity purposes. (These assumptions were developed by ITD, based on information in the 1984 Drilling Fluids Survey by the American Petroleum Institute (API)).

Stuck Pipe Assumptions: The Offshore Operators' Committee (OOC) surveyed 2,287 wells drilled in the Gulf of Mexico from 1983 to 1986 (see FR 1988a). The study examined the number of wells drilled with water-based fluid each year, the number of stuck pipe incidents, the spotting fluid used to free the stuck pipe, and whether or not the "pill" or slug of the spotting fluid was successful in freeing the pipe. Of the 2,287 wells surveyed, 506, or 22

TABLE 6-1

REGIONAL VOLUMES OF DRILLING FLUIDS AND DRILL CUTTINGS
0 - 10,000 FT INTERVAL

	Volume of Effluent (bbl)	
Region	Fluids	Cuttings
Gulf	6,932	1,471
Pacific	6,047	1,265
Alaska	6,385	1,345
Atlantic	9,476	2,577

Source: Environmental Protection Agency,
Industrial Technology Division.

percent, had stuck pipe incidents. On this basis, the cost modeling efforts assume 22 percent of all wells have stuck pipe incidents between 8,000 and 10,000 ft.

The OOC survey indicated that 298 of 506 (or 59 percent) stuck pipe incidents were treated with a pill of diesel oil. The remaining 41 percent of the stuck pipe incidents were treated with a mineral oil. These percentages were used to estimate the number of wells for which a diesel pill would have been used and which now must use mineral oil in order to avoid barging. As a result, 9 percent of the wells would use a mineral oil pill, and 13 percent that would have used a diesel oil pill, now choose to substitute a mineral oil pill. All fluids with diesel oil pills would have to be barged due to the toxicity of the remaining fluid. However, 44 percent of the fluids with mineral oil pills can be discharged because they pass the toxicity and static sheen tests. Thus, by substituting mineral for diesel pills, less barging is required.

Toxicity Test Failure Rates: The failure rate assumptions for the toxicity test determine the amount of drilling fluids and cuttings that cannot be discharged. Because operators are required to substitute mineral oil for diesel oil, the mineral oil failure rates are used wherever oil is added to the drilling fluid. Separate categories are maintained in the calculations, however, to identify the amount of drilling fluids affected by the product substitution requirement and the costs associated with the substitution of mineral oil for diesel oil.

The data for the toxicity failure rates come from five sources. The first two data sets are field fluid data collected by the American Petroleum Institute and submitted to the Agency in August 1985 and October 1986. The third data set includes the analytical results for field fluids collected during the Diesel Pill Monitoring Program conducted by EPA, in cooperation with API, from November 1985 through September 1987. The fourth data set is field fluid information generated by industry and submitted to EPA Region VI under the alternative toxicity request program. The fifth set of data is discharge monitoring reports provided to EPA Region VI by industry under the terms of the NPDES general permit for oil and gas operations in the Gulf of Mexico. One percent of the water-based drilling fluids to which no oil has been added for lubricity or spotting purposes is assumed to fail the toxicity test. Thirty-three percent of the wells to which mineral oil has been added as a lubricity agent are assumed to fail the toxicity test. Where oil has been used as a spotting agent, 56 percent of the fluids are assumed to fail the toxicity test. Table 6-2 summarizes the toxicity test failure rates for water-based drilling fluids.

Static Sheen Test Failure Rates: No water-based drilling fluid, even those to which oil has been added for lubricity, spotting, or combined purposes, is assumed to fail the static sheen test. All drill cuttings associated with water-based fluids are assumed to pass the visual (BPT) and the static sheen (BAT/NSPS) tests and may be discharged. The use of oil for lubricity or spotting purposes does not cause the cuttings to fail the static sheen test. Cuttings associated with oil-based fluids are assumed to fail the visual sheen test even after washing. Costs associated with barging these cuttings are BPT costs.

Zero Discharge of Drilling Effluents: Three of the regulatory options considered include zero discharge of drilling fluids and drill cuttings. (The zero discharge requirement is presumed to be met by barging the wastes to shore for disposal.) First is the Zero Discharge option where all drilling fluids and cuttings are barged to shore for treatment and disposal. The other two options require barging of fluids and cuttings from wells drilled within 4 miles of the shore or less, and limits on toxicity, sheen, and metals content of the fluids from operations beyond 4 miles. The two options are distinguished by the limitations on the metals content of the barite or discharged fluids. The percentage of wells projected to occur within 4 miles differs by region. Table 4-27 shows these percentages.

Monitoring Requirements: Table 6-3 summarizes monitoring cost components for both drilling fluids and drill cuttings. Fluids and cuttings that fall under mandatory barging requirements are not monitored. No monitoring costs are associated with drill cuttings or drilling fluids in the 10,000 to 14,000-ft depth because of the use of an oil-based fluid and the proposed outright prohibition on their discharge.

6.1.2 Current Permit Requirements

The current general permits for the Gulf of Mexico, Southern California, and Alaska already contain requirements that are more stringent than BPT guidelines. In some cases, the requirements exceed some of the options under consideration. These requirements are summarized in Table 6-4 and are briefly described below (FR 1985, FR 1986, and FR 1988b).

TABLE 6-2

TOXICITY AND STATIC SHEEN FAILURE RATES FOR WATER-BASED DRILLING FLUIDS - 0 TO 10,000 FEET

Well Depth and Condition	Percentage of Drilling Fluids	No Lubricity Needed (88%)	Mineral Lubricity Used (8.16%)	Diesel Lubricity Used (3.84%) (Substitute Mineral Lubricity)
Fluids - 0 to 8,000 ft.				
Discharge		99%	67%	67%
Fail Toxicity		1%	33%	33%
Fail Static Sheen		0%	0%	0%
Total, Fluids - 0 to 8,000 ft.	100%			
Fluids - 8,000 to 10,000 ft.				
No stuck pipe	78%			
Discharge		99%	67%	67%
Fail Toxicity		1%	33%	33%
Fail Static Sheen		0%	0%	0%
Stuck pipe - Mineral pill	9%			
Discharge		44%	44%	44%
Fail Toxicity		56%	56%	56%
Fail Static Sheen		0%	0%	0%
Stuck pipe - Diesel pill (Substitute Mineral pill)	13%			
Discharge		44%	44%	44%
Fail Toxicity		56%	56%	56%
Fail Static Sheen		0%	0%	0%
Total, Fluids - 8,000 to 10,000 ft.	100%			

* Drilling fluids that fail either the toxicity or the static sheen test are assumed to be barged to shore for land disposal.
Source: Environmental Protection Agency, Industrial Technology Division.

TABLE 6-3

OFFSHORE OIL AND GAS MONITORING COSTS FOR DRILLING FLUIDS AND DRILL CUTTINGS

Waste Stream	Test	Component Costs ($1986) Toxicity	Mercury	Cadmium	Static Sheen	Diesel Content	Cost per Well
	Cost per Sample	$1,000	$50	$50	$25	$75	
	Number of Samples*	2	2	2	10/20*	2	
DRILLING FLUIDS		$2,000	$100	$100	$250	$150	$2,600
DRILL CUTTINGS					$500		$500

* Static sheen tests conducted daily on cuttings and every other day on drilling fluids, assuming a twenty day drilling operation.

Source: Environmental Protection Agency, Industrial Technology Division.

TABLE 6-4

SUMMARY OF CURRENT REQUIREMENTS FOR DRILLING FLUIDS

Requirement	Region Gulf of Mexico	 Pacific	 Alaska
No discharge of oil-based fluids (BPT requirement)	Yes	Yes	Yes
Mandatory barging based on distance from shore	No	No	No
Metals limitation	No	Yes	Yes
effluent		barite	barite
mercury (mg/kg)		1	1
cadmium (mg/kg)		2	3
No discharge of diesel oil in detectable amounts (Mineral oil substitution)			
lubricity	Yes	Yes	Yes
pill	No**	No**	Yes
Toxicity limitation	Yes	Yes	No
limit	30,000 ppm spp*	30,000 ppm spp*	
No discharge of "free oil"			
static sheen test	No	Yes	Yes

* suspended particulate phase.
** Diesel pill plus a 50 bbl buffer of drilling fluid on either side of the pill cannot be discharged; toxicity limit must be met by remaining fluid.

Source: FR, 1985; FR, 1986; and FR, 1988.

No Discharge of Oil-Based Fluids: This is a BPT requirement and is included in all regional permits.

Mandatory Barging Based on Distance from Shore: There are no current requirements to barge fluids based on distance from shore.

Metals Limitation: The Gulf of Mexico permit has no requirement to limit metals. Alaska and the Pacific place limitations on the metals in the barite, while various proposed regulatory options limit the metals content either in the barite or in the discharged drilling fluid and drill cuttings. Table 6-4 shows the metals limitations for each region. The limits for the Pacific and Alaska are more stringent than the 5,3 option under consideration here.

No Discharge of Diesel Oil: All regions ban the discharge of fluids where diesel oil has been used for lubricity. In the Gulf of Mexico and the Pacific, the diesel oil pill and a minimum of 50 bbls of fluid on either side of the pill must be withheld. The remainder of the fluid can be discharged if it meets toxicity limitations. In Alaska, operators must withhold a mineral oil pill plus a 50 bbl buffer on either side of the pill.

Toxicity Limits: Both the Gulf and Pacific require testing the fluid for toxicity and have a 30,000 ppm spp limit. Alaska requires a bioassay test for each mud system where mineral oil lubricity or a spotting agent is used, or, if no mineral oil is used, one end-of-well bioassay test. The data appear to be used to check the list of approved fluids and additives, not to determine whether the fluid must be barged. (The approved list uses a toxicity limit of 30,000 ppm spp as its underlying basis.)

No Discharge of "Free Oil": Alaska and the Pacific require the static sheen test while the Gulf requires the visual sheen test. The distinction is moot because anything assumed to fail the static sheen test is considered covered by the BPT level of control for the purpose of costing the current analysis.

Monitoring Costs: Table 6-5 summarizes the incremental monitoring costs borne by future drilling operations. Zero entries indicate that testing already is required under current permit requirements. Note that no region requires testing for oil content at this time.

TABLE 6-5

SUMMARY OF INCREMENTAL MONITORING COSTS FROM CURRENT DRILLING FLUIDS BASELINE

Monitoring Requirement	Region			
	Gulf	Pacific	Alaska	Atlantic
Drilling Fluids				
Mercury	$100	$0	$0	$100
Cadmium	$100	$0	$0	$100
Toxicity	$0	$0	$2,000	$2,000
Static Sheen	$250	$0	$0	$250
No diesel in detectable amounts	$150	$150	$150	$150
Total Drilling Fluids Monitoring Cost	$600	$150	$2,150	$2,600
Drill Cuttings				
Static Sheen Test	$500	$0	$0	$500

Note: Zero entries denote that the monitoring requirement already exists in current permits.

6.1.3 Cost of Regulatory Options

The cost of a regulatory option for drilling fluids and drill cuttings depends on the average annual number of projected wells. That average will vary depending upon the price of oil and whether economically feasible development is restricted by environmental considerations. Section Four discusses these factors and presents four sets of projections.

The costs presented in Tables 6-6 through 6-9 are for the $21/bbl unrestricted scenario. These tables summarize the cost for each regulatory option by region. Although diesel pills may be used as long as (1) the pill and a 100-barrel minimum buffer are barged, and (2) the remaining fluid passes the toxicity test, ERG models the Gulf and Pacific as substituting mineral oil for diesel oil in pills because it is a lower cost option on the average (Kaplan, 1989a).

Table 6-6 presents the costs for the Gulf of Mexico with the costs for the 5,3 All option given in the middle column. The use of 5,3 barite is considered a no-cost option. (There are adequate supplies of barite meeting these metals limitations, so no price increase would be incurred; see Kaplan and Meyers, 1987). Although the current permit for the Gulf does not specify metals limitations in the barite or discharged drilling fluid, no cost is associated with the use of 5,3 barite. The current permit already requires the substitution of mineral oil for diesel and toxicity testing, so these items accrue no costs. No fluids or cuttings are assumed to fail the static sheen test, so no costs are incurred by this requirement either. The only costs incurred by moving to the 5,3 option in the Gulf are the increased monitoring costs for fluids and cuttings. These costs are $600 and $500, respectively, (see Table 6-5) for an average cost of $1,100 per well.

1,1 All: Compliance with the 1,1 All option assumes the use of "clean" barite for all wells. In the Gulf, "clean" barite incurs a 15 percent price increase. This item is listed in the "Clean barite" line. Like the 5,3 All option, this option incurs additional monitoring costs.

Options Involving Mandatory Barging, Including those Based on Distance to Shore: The costs listed in the "zero discharge" rows are the costs associated with barging all fluids and cuttings from all wells (in the Zero Discharge option) or from wells within 4 miles from shore (in the 4-Mile Barge options). Because these fluids will be barged *a priori*, there is no need to substitute mineral oil for diesel, to test for toxicity, or to barge the fluids that fail

TABLE 6-6

ANNUAL REGULATORY COST OF ALTERNATIVE POLLUTION CONTROL OPTIONS ($000 1986 DOLLARS)
DRILLING FLUIDS AND DRILL CUTTINGS

GULF OF MEXICO
UNRESTRICTED ACTIVITY

	REGULATORY OPTIONS				
Parameter	Zero Discharge	1,1 All	5,3 All	4-MILE BARGE, 1,1 OTHER	4-MILE BARGE, 5,3 OTHER
DRILLING FLUID COSTS	$158,193	$8,108	$429	$23,812	$16,805
Clean barite	$0	$7,679	$0	$7,007	$0
Mineral oil substitutition for diesel oil	($1,259)	$0	$0	($126)	($126)
Toxicity test failure	($15,506)	$0	$0	($1,551)	($1,551)
Static sheen test failure	$0	$0	$0	$0	$0
Zero discharge	$176,388	$0	$0	$18,239	$18,239
Monitoring costs	($1,430)	$429	$429	$243	$243
DRILL CUTTINGS COSTS	$53,666	$358	$358	$5,688	$5,688
Static sheen test failure	$0	$0	$0	$0	$0
No association with oil-based fluids	$0	$0	$0	$0	$0
Zero discharge	$53,666	$0	$0	$5,367	$5,367
Monitoring costs	$0	$358	$358	$322	$322
TOTAL ANNUAL COSTS	$211,859	$8,466	$787	$29,500	$22,493
ANNUAL COST PER WELL	$296	$12	$1.1	$41	$31

Source: Industrial Technology Division, Environmental Protection Agency.

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TABLE 6-7

ANNUAL REGULATORY COST OF ALTERNATIVE POLLUTION CONTROL OPTIONS ($000 1986 DOLLARS)
DRILLING FLUIDS AND DRILL CUTTINGS

PACIFIC
UNRESTRICTED ACTIVITY

	REGULATORY OPTIONS				
Parameter	Zero Discharge	1,1 All	5,3 All*	4-MILE BARGE, 1,1 OTHER	4-MILE BARGE, 5,3 OTHER*
DRILLING FLUID COSTS	$44,873	$885	$36	$14,709	$14,536
Clean barite	($1,697)	$849	$0	$172	$0
Mineral oil substitutition for diesel oil	($397)	$0	$0	($119)	($119)
Toxicity test failure	($4,005)	$0	$0	($1,202)	($1,202)
Static sheen test failure	$0	$0	$0	$0	$0
Zero discharge	$51,553	$0	$0	$15,857	$15,857
Monitoring costs	($581)	$36	$36	($149)	($149)
DRILL CUTTINGS COSTS	$15,180	$0	$0	$4,554	$4,554
Static sheen test failure	$0	$0	$0	$0	$0
No association with oil-based fluids	$0	$0	$0	$0	$0
Zero discharge	$15,298	$0	$0	$4,589	$4,589
Monitoring costs	($119)	$0	$0	($36)	($36)
TOTAL ANNUAL COSTS	$60,053	$885	$36	$19,262	$19,090
ANNUAL COST PER WELL	$253	$4	$0	$81	$81

* Current permit requires the use of 1,2 barite. This requirement cannot be relaxed when considering regulatory options.
Source: Industrial Technology Division, Environmental Protection Agency.

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TABLE 6-8

ANNUAL REGULATORY COST OF ALTERNATIVE POLLUTION CONTROL OPTIONS ($000 1986 DOLLARS)
DRILLING FLUIDS AND DRILL CUTTINGS

ALASKA
UNRESTRICTED ACTIVITY

Parameter *	REGULATORY OPTIONS: Zero Discharge	1,1 All	5,3 All
DRILLING FLUID COSTS	$2,677	$334	$248
Clean barite	($43)	$86	$0
Mineral oil substitutition for diesel oil	($20)	$0	$0
Toxicity test failure	$0	$222	$222
Static sheen test failure	$0	$0	$0
Zero discharge	$2,745	$0	$0
Monitoring costs	($5)	$26	$26
DRILL CUTTINGS COSTS	$1,229	$0	$0
Static sheen test failure	$0	$0	$0
No association with oil-based fluids	$0	$0	$0
Zero discharge	$1,235	$0	$0
Monitoring costs	($6)	$0	$0
TOTAL ANNUAL COSTS	$3,906	$334	$248
ANNUAL COST PER WELL	$325	$28	$21

* Current permit requires the use of 1,3 barite. This requirement cannot be relaxed when considering regulatory options.

NOTE: Alaska is exempted from the 4-mile Barge requirement. Restrictions on the metals content of the barite and other components of the 1,1 All and the 5,3 All options remain in place.

Source: Industrial Technology Division, Environmental Protection Agency.

TABLE 6-9

ANNUAL REGULATORY COST OF ALTERNATIVE POLLUTION CONTROL OPTIONS ($000 1986 DOLLARS)
DRILLING FLUIDS AND DRILL CUTTINGS

ATLANTIC
UNRESTRICTED ACTIVITY

	REGULATORY OPTIONS				
Parameter	Zero Discharge	1,1 All	5,3 All	4-MILE BARGE, 1,1 OTHER	4-MILE BARGE, 5,3 OTHER
DRILLING FLUID COSTS	$5,298	$835	$663	$835	$663
Clean barite	$0	$172	$0	$172	$0
Mineral oil substitutition for diesel oil	$0	$32	$32	$32	$32
Toxicity test failure	$0	$589	$589	$589	$589
Static sheen test failure	$0	$0	$0	$0	$0
Zero discharge	$5,298	$0	$0	$0	$0
Monitoring costs	$0	$42	$42	$42	$42
DRILL CUTTINGS COSTS	$2,104	$9	$9	$9	$9
Static sheen test failure	$0	$0	$0	$0	$0
No association with oil-based fluids	$0	$0	$0	$0	$0
Zero discharge	$2,104	$0	$0	$0	$0
Monitoring costs	$0	$9	$9	$9	$9
TOTAL ANNUAL COSTS	$7,402	$844	$672	$844	$672
ANNUAL COST PER WELL	$463	$53	$42	$53	$42

Source: Industrial Technology Division, Environmental Protection Agency.

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toxicity. Hence there are negative entries for mineral oil substitution, toxicity test failure, and monitoring costs. The operators would no longer incur these costs, which would be incurred under current permit conditions. For the same reason, a lower cost for clean barite is seen in the 4-Mile Barge; 1,1 Other option than in the 1,1 All option because only wells beyond 4 miles would have to use clean barite.

The costs for the Pacific are given in Table 6-7. In this region, current permit conditions require the use of barite with 1 mg/kg mercury and 2 mg/kg cadmium. This requirement cannot be relaxed. An additional 5 percent increase is associated with moving to the cleaner barite (Kaplan, 1989b).

Table 6-8 summarizes the cost for Alaska. For Alaska, cadmium and mercury in the barite are limited to 3 mg/kg and 1 mg/kg, respectively. Changing to clean barite to meet the 1,1 All option incurs an additional 10 percent cost increase (Kaplan, 1989b). Current practices include the costs for mineral oil substitution. Monitoring costs include testing for oil content and toxicity. Note that no costs are listed in the Alaska region for either of the 4-Mile Barge options. Due to the dangers, high costs, and uncertainties of barging in arctic conditions, Alaska has been exempted from any zero discharge requirement under these options. Instead, wells in this region must comply with the 1,1 All or 5,3 All requirements under the 4-Mile Barge; 1,1 Other and the 4-Mile Barge; 5,3 Other options, respectively.

There are no permits with more stringent requirements than BPT for the Atlantic. Table 6-9 presents the costs for the regulatory options for this region. Since no wells are assumed to occur within 4 miles from shore, there is no difference between the respective 4-Mile Barge and the 1,1 All or 5,3 All options.

Annual Total and Per-Well Costs: The total annual cost and regional per-well costs are summarized in Table 6-10. The per-well costs are weighted averages for all wells; i.e., the costs reflect the percentage of wells that barge and the percentage that do not barge. These values are used in the economic impact analysis (see Sections Seven through Ten). The total annual costs range from $2 million (1986 dollars) for the 5,3 All option to $283 million (1986 dollars) for the Zero Discharge option.

Tables 6-11 through 6-14 present the annual regulatory costs by region under the $21/bbl restricted development scenario. Note that the costs in the Gulf and Alaska regions do not change under this assumption. There are no costs in the Atlantic region, since no activity is projected to occur there.

TABLE 6-10

SUMMARY TABLE OF REGULATORY COSTS OF ALTERNATIVE POLLUTION CONTROL OPTIONS
NSPS DRILLING FLUIDS AND DRILL CUTTINGS
ANNUAL REGULATORY COST ($000 1986 DOLLARS)

UNRESTRICTED ACTIVITY

	REGULATORY OPTIONS				
Parameter	Zero Discharge	1,1 All	5,3 All	4-MILE BARGE, 1,1 OTHER*	4-MILE BARGE, 5,3 OTHER**
TOTAL COST	$283,219	$10,527	$1,741	$49,940	$42,503
PER WELL COST					
Gulf of Mexico	$296	$12	$1	$41	$31
Pacific	$253	$4	$0	$81	$81
Alaska	$325	$28	$21	$28	$21
Atlantic	$463	$53	$42	$53	$42

* Except for Alaska which is 1,1 All.
** Except for Alaska which is 5,3 All.
Source: ERG estimates.

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TABLE 6-11

ANNUAL REGULATORY COST OF ALTERNATIVE POLLUTION CONTROL OPTIONS ($000 1986 DOLLARS)
DRILLING FLUIDS AND DRILL CUTTINGS

GULF OF MEXICO
RESTRICTED ACTIVITY

	REGULATORY OPTIONS				
Parameter	Zero Discharge	1,1 All	5,3 All	4-MILE BARGE, 1,1 OTHER	4-MILE BARGE, 5,3 OTHER
DRILLING FLUID COSTS	$158,193	$8,108	$429	$23,812	$16,805
Clean barite	$0	$7,679	$0	$7,007	$0
Mineral oil substitutition for diesel oil	($1,259)	$0	$0	($126)	($126)
Toxicity test failure	($15,506)	$0	$0	($1,551)	($1,551)
Static sheen test failure	$0	$0	$0	$0	$0
Zero discharge	$176,388	$0	$0	$18,239	$18,239
Monitoring costs	($1,430)	$429	$429	$243	$243
DRILL CUTTINGS COSTS	$53,666	$358	$358	$5,688	$5,688
Static sheen test failure	$0	$0	$0	$0	$0
No association with oil-based fluids	$0	$0	$0	$0	$0
Zero discharge	$53,666	$0	$0	$5,367	$5,367
Monitoring costs	$0	$358	$358	$322	$322
TOTAL ANNUAL COSTS	$211,859	$8,466	$787	$29,500	$22,493
ANNUAL COST PER WELL	$296	$12	$1.1	$41	$31

Source: Industrial Technology Division, Environmental Protection Agency.

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TABLE 6-12

ANNUAL REGULATORY COST OF ALTERNATIVE POLLUTION CONTROL OPTIONS ($000 1986 DOLLARS)
DRILLING FLUIDS AND DRILL CUTTINGS

PACIFIC
RESTRICTED ACTIVITY

	REGULATORY OPTIONS				
Parameter	Zero Discharge	1,1 All	5,3 All*	4-MILE BARGE, 1,1 OTHER	4-MILE BARGE, 5,3 OTHER*
DRILLING FLUID COSTS	$6,059	$120	$5	$120	$5
Clean barite	($229)	$115	$0	$115	$0
Mineral oil substitutition for diesel oil	($54)	$0	$0	$0	$0
Toxicity test failure	($541)	$0	$0	$0	$0
Static sheen test failure	$0	$0	$0	$0	$0
Zero discharge	$6,961	$0	$0	$0	$0
Monitoring costs	($78)	$5	$5	$5	$5
DRILL CUTTINGS COSTS	$2,049	$0	$0	$0	$0
Static sheen test failure	$0	$0	$0	$0	$0
No association with oil-based fluids	$0	$0	$0	$0	$0
Zero discharge	$2,065	$0	$0	$0	$0
Monitoring costs	($16)	$0	$0	$0	$0
TOTAL ANNUAL COSTS	$8,108	$120	$5	$120	$5
ANNUAL COST PER WELL	$253	$4	$0	$4	$0

* Current permit requires the use of 1,2 barite. This requirement cannot be relaxed when considering regulatory options.
Source: Industrial Technology Division, Environmental Protection Agency.

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TABLE 6-13

ANNUAL REGULATORY COST OF ALTERNATIVE POLLUTION CONTROL OPTIONS ($000 1986 DOLLARS)
DRILLING FLUIDS AND DRILL CUTTINGS

ALASKA
RESTRICTED ACTIVITY

Parameter	REGULATORY OPTIONS Zero Discharge	1,1 All	5,3 All*
DRILLING FLUID COSTS	$2,677	$334	$248
Clean barite	($43)	$86	$0
Mineral oil substitutition for diesel oil	($20)	$0	$0
Toxicity test failure	$0	$222	$222
Static sheen test failure	$0	$0	$0
Zero discharge	$2,745	$0	$0
Monitoring costs	($5)	$26	$26
DRILL CUTTINGS COSTS	$1,229	$0	$0
Static sheen test failure	$0	$0	$0
No association with oil-based fluids	$0	$0	$0
Zero discharge	$1,235	$0	$0
Monitoring costs	($6)	$0	$0
TOTAL ANNUAL COSTS	$3,906	$334	$248
ANNUAL COST PER WELL	$325	$28	$21

* Current permit requires the use of 1,3 barite. This requirement cannot be relaxed when considering regulatory options.
NOTE: Alaska is exempted from the 4-mile barge requirement. Restrictions on the metals content of the barite and other components of the 1,1 All and the 5,3 All options remain in place
Source: Industrial Technology Division, Environmental Protection Agency.

TABLE 6-14

ANNUAL REGULATORY COST OF ALTERNATIVE POLLUTION CONTROL OPTIONS ($000 1986 DOLLARS)
DRILLING FLUIDS AND DRILL CUTTINGS

ATLANTIC
RESTRICTED ACTIVITY

Parameter	REGULATORY OPTIONS				
	Zero Discharge	1,1 All	5,3 All	4-MILE BARGE, 1,1 OTHER	4-MILE BARGE, 5,3 OTHER
DRILLING FLUID COSTS	$0	$0	$0	$0	$0
Clean barite	$0	$0	$0	$0	$0
Mineral oil substitutition for diesel oil	$0	$0	$0	$0	$0
Toxicity test failure	$0	$0	$0	$0	$0
Static sheen test failure	$0	$0	$0	$0	$0
Zero discharge	$0	$0	$0	$0	$0
Monitoring costs	$0	$0	$0	$0	$0
DRILL CUTTINGS COSTS	$0	$0	$0	$0	$0
Static sheen test failure	$0	$0	$0	$0	$0
No association with oil-based fluids	$0	$0	$0	$0	$0
Zero discharge	$0	$0	$0	$0	$0
Monitoring costs	$0	$0	$0	$0	$0
TOTAL ANNUAL COSTS	$0	$0	$0	$0	$0
ANNUAL COST PER WELL	$0	$0	$0	$0	$0

Source: Industrial Technology Division, Environmental Protection Agency.

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Costs in the Pacific region decline due to the reduced amount of activity projected. The total annual costs and regional per-well costs under the restricted activity scenario are summarized in Table 6-15. Total annual costs range from $1 million (1986 dollars) for the 5,3 All option to $224 million (1986 dollars) for the Zero Discharge option.

As described in Section Four, four alternative scenarios have been analyzed to account for possible variations in regulatory costs due to oil price changes and different levels of development. Table 6-16 summarizes the total annual costs under each of the four alternative scenarios. The per-well costs do not change, revert to the costs for another option, or go to zero depending upon assumptions for future development. For example, under the restricted development variations, there are no wells within 4 miles of shore in the Pacific; thus, the per-well costs revert to the 1,1 All or 5,3 All per-well costs. The cost for the 4-Mile Barge; 1,1 Other option ranges from $26 million to $60 million (1986 dollars) depending on the assumptions for the price of oil and the level of development.

6.2 PRODUCED WATER - BAT

Section One presents the regulatory options for increased pollution controls on produced water from existing projects. There are two basic methods:

- Filtration and discharge
- Injection

The options under consideration are combinations of one or both disposal methods depending upon the location of the platform (within 4 miles or beyond 4 miles from shore).

Two sets of capital and operation and maintenance (O&M) costs were developed for filtration and reinjection. The final set of costs, based upon membrane filtration technology, assumes that <u>no</u> platform addition is necessary and uses a multiplier of 1.5 to cover the costs of transportation to the offshore location and other considerations.

The second set of costs, based upon granular filtration technology, reflects two important cost assumptions:

TABLE 6-15

SUMMARY TABLE OF REGULATORY COSTS OF ALTERNATIVE POLLUTION CONTROL OPTIONS
NSPS DRILLING FLUIDS AND DRILL CUTTINGS
ANNUAL REGULATORY COST ($000 1986 DOLLARS)

RESTRICTED ACTIVITY

	REGULATORY OPTIONS				
Parameter	Zero Discharge	1,1 All	5,3 All	4-MILE BARGE, 1,1 OTHER*	4-MILE BARGE, 5,3 OTHER**
TOTAL COST	$223,872	$8,919	$1,039	$29,954	$22,746
PER WELL COST					
Gulf of Mexico	$296	$12	$1	$41	$31
Pacific	$253	$4	$0	$4	$0
Alaska	$325	$28	$21	$28	$21
Atlantic	$0	$0	$0	$0	$0

* Except for Alaska which is 1,1 All. M&C$-RES.WK3 19-Nov-90
** Except for Alaska which is 5,3 All.
Source: ERG estimates.

TABLE 6-16

ANNUAL COST OF POLLUTION CONTROL OPTIONS
NSPS DRILL FLUIDS AND DRILL CUTTINGS
MILLIONS OF DOLLARS, 1986 DOLLARS

	Regulatory Options				
Scenario	Zero Discharge	1,1 All	5,3 All	4-Mile Barge; 1,1 Other	4-Mile Barge; 5,3 Other
$21/bbl - Unrestricted	$283	$11	$2	$50	$43
$21/bbl - Restricted	$224	$9	$1	$30	$23
$32/bbl - Unrestricted	$344	$14	$4	$60	$51
$15/bbl - Restricted	$197	$8	$1	$26	$20

Source: ERG estimates.

- Platform additions are required to accommodate the extra equipment. Platform additions can be two-thirds the entire capital cost for some projects.

- A multiplier of 3.5 is used to address the costs of getting the material to its offshore location, etc.

The costing assumptions, capital costs, and O&M costs were developed by EPA Industrial Technology Division, and are discussed in more detail in the Development Document.

The injection option is subdivided into onshore and offshore injection. Under the granular filter costs, it may be less expensive to drill a disposal well onshore and pipe the produced water to shore for disposal. ERG assumes 37 percent of the platforms within 4 miles use onshore injection based on information in WHA, 1984. For the membrane filter costs, the offshore injection option is less expensive for most Gulf model projects than piping the fluids to shore for treatment and disposal. No onshore injection is considered with the membrane filter cost estimates.

Only projects in the Gulf of Mexico and the Pacific need to be considered in the BAT analysis. The only offshore field presently in production in Alaska is the Endicott field in the Beaufort Sea. This project must already inject produced water due to State requirements. There is no current production from projects in the Atlantic. Both the Gulf of Mexico and the Pacific have oil-with-gas and gas-only projects. The Gulf of Mexico also has a small number of oil-only projects. Table 6-17 summarizes the BAT projects by region, size, and type of production; details on the platform count are given in Appendix H. Table 6-18 summarizes the regional capital and annual O&M costs for the BAT projects.

The model-specific capital and O&M costs are entered into the BAT economic models to calculate the annualized cost of the regulation. The annualized costs are calculated over the remaining lifetime of the project and address the situation where the project shuts down early due to an increase in the annual O&M costs. Tables 6-19 through 6-22 list the capital, O&M, and annualized cost for each project and regulatory option.

Total annualized costs are obtained by multiplying the appropriate number of structures by the cost of each disposal option and summing over all entries. Table 6-23 lists the total annualized cost by disposal option for the granular filter and membrane filter costs. For the granular filter scenario, the costs range from $41 million (1986 dollars) for the projects

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TABLE 6-17

EXISTING STRUCTURES BY REGION

Structure Type	Oil Only <= 4 miles	Oil Only > 4 miles	Oil and Gas <= 4 miles	Oil and Gas > 4 miles	Gas Only <= 4 miles	Gas Only > 4 miles	Total <= 4 miles	Total > 4 miles	Total
	NUMBER OF STRUCTURES								
Gulf 1a	26	38	27	193	53	337	106	568	674
Gulf 1b	1	9	13	82	22	228	36	319	355
Gulf 4	23	18	10	101	8	156	41	275	316
Gulf 6	0	18	2	124	1	156	3	298	301
Gulf 12	0	22	3	215	0	104	3	341	344
Gulf 24	0	5	8	188	0	39	8	232	240
Gulf 40	0	1	0	2	0	0	0	3	3
Gulf 58	0	0	0	0	0	0	0	0	0
Gulf Totals	50	111	63	905	84	1,020	197	2,036	2,233
Pacific 16	0	0	7	1	0	1	7	2	9
Pacific 40	0	0	0	6	0	0	0	6	6
Pacific 70	0	0	4	8	0	0	4	8	12
Pacific Totals	0	0	11	15	0	1	11	16	27
Atlantic	No existing facilities								
Alaska	No facilities that do not already re-inject produced water								
Totals	50	111	74	920	84	1,021	208	2,052	2,260

Note: Structures in the Gulf of Mexico have been classified according to the number of producing wells. Structures in the Pacific have been classified according to the number of wellslots.

Source: MMS, 1988; CCC, 1988; SAS printout kre_bat6.out; SAS runs dated July 1990.

TABLE 6-18

BAT PRODUCED WATER
TOTAL CAPITAL AND ANNUAL O&M COSTS BY REGION
$MILLIONS, 1986 DOLLARS

Technology Cost	Effluent Control Option	Region	Capital Costs	Annual O&M Costs
Membrane Filter	Zero Discharge	Gulf	$2,224.6	$151.5
		Pacific	$133.7	$9.2
		Total	$2,358.3	$160.7
	All Filter	Gulf	$393.1	$97.9
		Pacific	$31.0	$6.4
		Total	$424.1	$104.3
	4-Mile Filter; BPT Other	Gulf	$23.9	$6.1
		Pacific	$11.4	$2.2
		Total	$35.3	$8.4
Granular Filter	Zero Discharge	Gulf	$4,461.4	$198.6
		Pacific	$330.1	$12.0
		Total	$4,791.5	$210.6
	All Filter	Gulf	$2,235.6	$136.5
		Pacific	$179.1	$8.7
		Total	$2,414.7	$145.3
	4-Mile Filter; BPT Other	Gulf	$116.7	$8.0
		Pacific	$70.1	$3.2
		Total	$186.8	$11.2

Source: Environmental Protection Agency, Industrial Technology Division.

TABLE 6-19

BAT POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
OIL AND GAS PLATFORMS
GULF OF MEXICO

		Pollution Control Costs ($000, 1986 Dollars)		
Project	Scenario	Capital	O&M	Annualized
Gulf 1a	G-Zero Discharge	$672	$29	$144
	G-Filtration	$286	$18	$61
	Onshore	$460	$17	$89
	M-Zero Discharge	$385	$24	$88
	M-Filtration	$64	$14	$22
Gulf 1b	G-Zero Discharge	$2,019	$99	$441
	G-Filtration	$579	$57	$141
	Onshore	$1,710	$67	$331
	M-Zero Discharge	$1,426	$83	$299
	M-Filtration	$170	$45	$66
Gulf 4	G-Zero Discharge	$2,783	$124	$518
	G-Filtration	$1,237	$78	$250
	Onshore	$1,846	$71	$334
	M-Zero Discharge	$1,546	$98	$312
	M-Filtration	$262	$59	$87
Gulf 6	G-Zero Discharge	$3,361	$143	$587
	G-Filtration	$1,792	$96	$330
	Onshore	$1,890	$74	$324
	M-Zero Discharge	$1,589	$106	$310
	M-Filtration	$298	$67	$99
Gulf 12	G-Zero Discharge	$3,471	$143	$636
	G-Filtration	$2,812	$124	$523
	Onshore	$1,970	$78	$339
	M-Zero Discharge	$715	$90	$183
	M-Filtration	$365	$80	$122
Gulf 24	G-Zero Discharge	$4,312	$222	$787
	G-Filtration	$3,185	$194	$607
	Onshore	$2,610	$80	$408
	M-Zero Discharge	$1,079	$131	$254
	M-Filtration	$426	$113	$154
Gulf 40	G-Zero Discharge	$5,035	$292	$907
	G-Filtration	$3,393	$248	$656
	M-Zero Discharge	$1,471	$192	$349
	M-Filtration	$502	$165	$206
Gulf 58	G-Zero Discharge	$6,071	$378	$1,077
	G-Filtration	$3,647	$314	$724
	M-Zero Discharge	$2,130	$271	$499
	M-Filtration	$596	$227	$273

Notes: There are no Gulf 40 or Gulf 58 projects within 4-miles from shore at present.
G refers to granular filtration costs for injection and filtration.
M refers to membrane filtration costs for injection and filtration.
Source: ERG estimates.

TABLE 6-20

BAT POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
OIL AND GAS PLATFORMS
PACIFIC

		Pollution Control Costs ($000, 1986 Dollars)		
Project	Scenario	Capital	O&M	Annualized
Pacific 16	G-Zero Discharge	$7,700	$257	$1,983
	G-Filtration	$5,255	$206	$1,377
	Onshore	$4,248	$78	$1,045
	M-Zero Discharge	$2,258	$164	$650
	M-Filtration	$738	$125	$267
Pacific 40	G-Zero Discharge	$10,701	$405	$2,467
	G-Filtration	$5,979	$301	$1,438
	M-Zero Discharge	$4,183	$299	$1,077
	M-Filtration	$1,007	$214	$373
Pacific 70	G-Zero Discharge	$16,849	$620	$3,507
	G-Filtration	$8,322	$434	$1,837
	Onshore	$7,991	$180	$1,569
	M-Zero Discharge	$7,484	$500	$1,742
	M-Filtration	$1,553	$341	$557

Notes: G refers to granular filtration costs for injection and filtration.
M refers to membrane filtration costs for injection and filtration.

Source: ERG estimates.

TABLE 6-21

BAT POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
GAS PLATFORMS
GULF OF MEXICO AND PACIFIC REGIONS

		Pollution Control Costs ($000, 1986 Dollars)		
Project	Scenario	Capital	O&M	Annualized
Gulf 1a	G-Zero Discharge	$544	$21	$105
	G-Filtration	$132	$10	$30
	Onshore	$419	$12	$77
	M-Zero Discharge	$408	$20	$83
	M-Filtration	$37	$9	$14
Gulf 1b	G-Zero Discharge	$1,672	$78	$334
	G-Filtration	$174	$34	$55
	Onshore	$667	$39	$132
	M-Zero Discharge	$1,494	$77	$305
	M-Filtration	$48	$34	$36
Gulf 4	G-Zero Discharge	$2,175	$83	$393
	G-Filtration	$529	$39	$106
	Onshore	$1,675	$45	$270
	M-Zero Discharge	$1,634	$79	$294
	M-Filtration	$149	$36	$51
Gulf 6	G-Zero Discharge	$2,231	$86	$382
	G-Filtration	$563	$41	$113
	Onshore	$1,699	$48	$276
	M-Zero Discharge	$1,654	$80	$298
	M-Filtration	$164	$37	$55
Gulf 12	G-Zero Discharge	$1,155	$61	$212
	G-Filtration	$632	$49	$130
	Onshore	$1,593	$59	$270
	M-Zero Discharge	$507	$49	$112
	M-Filtration	$193	$41	$62
Gulf 24	G-Zero Discharge	$1,423	$69	$245
	G-Filtration	$844	$56	$158
	Onshore	$1,660	$66	$273
	M-Zero Discharge	$565	$53	$120
	M-Filtration	$236	$44	$69
Pacific 16	G-Zero Discharge	$2,100	$71	$432
	G-Filtration	$1,319	$57	$281
	M-Zero Discharge	$758	$54	$179
	M-Filtration	$375	$45	$104

Notes: There are no Gulf 40, Gulf 58, or Pacific 16 gas-only projects within 4 miles from shore at present.
G refers to granular filtration costs for injection and filtration.
M refers to membrane filtration costs for injection and filtration.
Source: ERG estimates.

TABLE 6-22

BAT POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
OIL ONLY PLATFORMS
GULF OF MEXICO

Project	Scenario	Pollution Control Costs ($000, 1986 Dollars)		
		Capital	O&M	Annualized
Gulf 1a	G-Zero Discharge	$664	$29	$142
	G-Filtration	$278	$18	$64
	Onshore	$459	$17	$96
	M-Zero Discharge	$384	$24	$88
	M-Filtration	$63	$14	$23
Gulf 1b	G-Zero Discharge	$2,016	$99	$440
	G-Filtration	$577	$57	$141
	Onshore	$1,708	$67	$359
	M-Zero Discharge	$1,425	$83	$321
	M-Filtration	$170	$45	$65
Gulf 4	G-Zero Discharge	$2,769	$123	$515
	G-Filtration	$1,223	$77	$247
	Onshore	$1,845	$71	$334
	M-Zero Discharge	$1,545	$97	$312
	M-Filtration	$261	$59	$89
Gulf 6	G-Zero Discharge	$3,340	$141	$615
	G-Filtration	$1,772	$95	$326
	Onshore	$1,888	$73	$324
	M-Zero Discharge	$1,587	$105	$310
	M-Filtration	$297	$67	$98
Gulf 12	G-Zero Discharge	$3,421	$140	$626
	G-Filtration	$2,764	$121	$513
	Onshore	$1,967	$78	$358
	M-Zero Discharge	$712	$88	$181
	M-Filtration	$362	$78	$120
Gulf 24	G-Zero Discharge	$4,302	$220	$783
	G-Filtration	$3,181	$192	$604
	Onshore	$2,596	$80	$427
	M-Zero Discharge	$1,076	$129	$260
	M-Filtration	$425	$111	$155
Gulf 40	G-Zero Discharge	$5,026	$292	$906
	G-Filtration	$3,389	$248	$656
	M-Zero Discharge	$1,468	$192	$358
	M-Filtration	$500	$165	$208
Gulf 58	G-Zero Discharge	$5,819	$365	$1,073
	G-Filtration	$3,642	$309	$719
	M-Zero Discharge	$1,886	$259	$459
	M-Filtration	$594	$223	$268

Notes: There are no Gulf 40 or Gulf 58 projects within 4-miles from shore at present.
G refers to granular filtration costs for injection and filtration.
M refers to membrane filtration costs for injection and filtration.
Source: ERG estimates.

TABLE 6-23

ANNUAL COST OF POLLUTION CONTROL OPTIONS
BAT PRODUCED WATERS
MILLIONS OF DOLLARS, 1986 DOLLARS

	Annualized Regulatory Cost	
Option	Granular Filtration	Membrane Filtration
Zero Discharge	$845	$491
All Filter	$480	$151
4-Mile Filter; BPT Other	$41	$13

Source: ERG estimates.

within 4 miles of shore which must filter and discharge produced water, to $845 million (1986 dollars) for all projects which must inject their produced water. For the membrane filter scenario, costs range from $13 to $491 million 1986 dollars for the same disposal options.

6.3 PRODUCED WATER - NSPS

The filtration/discharge and injection of produced water are also options for future projects that would fall under the New Source Performance Standards. Section Four describes the methodology used to estimate the number and type of new sources.

The capital, O&M costs, and the annualized costs are shown by project in Tables 6-24 through 6-27. Table 6-28 summarizes the total capital and annual O&M costs by region. The cost for each option is assumed to be the annualized cost in 2000, the last year in the time frame for the analysis. Annualized costs are cumulative over the 1986-2000 time period. The cost for the first year is calculated as follows:

- Multiply the annualized cost for a project by the number of such projects going into operation that year, and
- Sum the products over all projects.

For year two, the annualized cost is the cost associated with projects going into operation that year plus the annualized cost for the preceding year. Note that these costs apply on a per-project basis, and, therefore, do not vary between the restricted and unrestricted scenarios. The difference in total costs reflects the varying number of projects under each of the four scenarios.

Tables 6-29 and 6-30 present the annualized costs for NSPS projects under the $21/bbl unrestricted development scenario. Table 6-29 represents the costs assuming the use of granular filtration technology. The costs range from $27 million (1986 dollars) for projects within 4 miles of shore that must filter and discharge their produced water to $275 million (1986 dollars) for all projects that must inject their produced water. Similarly, Table 6-30 summarizes the annualized costs assuming the use of membrane filter technology. For comparison, the costs drop to $17 million and $202 million for the above-mentioned options.

TABLE 6-24

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
OIL AND GAS PLATFORMS
GULF OF MEXICO

Project	Scenario	Pollution Control Costs ($000, 1986 Dollars)		
		Capital	O&M	Annualized
Gulf 1b	G-Zero Discharge	$1,928	$97	$278
	Onshore	$1,711	$85	$245
	G-Filtration	$485	$55	$96
	M-Zero Discharge	$1,462	$84	$220
	M-Filtration	$205	$47	$62
Gulf 4	G-Zero Discharge	$2,227	$118	$313
	Onshore	$1,848	$94	$256
	G-Filtration	$707	$72	$130
	M-Zero Discharge	$1,571	$99	$235
	M-Filtration	$299	$61	$83
Gulf 6	G-Zero Discharge	$2,339	$128	$328
	Onshore	$1,892	$94	$257
	G-Filtration	$805	$81	$147
	M-Zero Discharge	$1,615	$108	$245
	M-Filtration	$341	$69	$94
Gulf 12	G-Zero Discharge	$1,598	$115	$242
	Onshore	$1,976	$94	$260
	G-Filtration	$990	$97	$171
	M-Zero Discharge	$746	$93	$145
	M-Filtration	$419	$83	$107
Gulf 24	G-Zero Discharge	$2,225	$163	$334
	Onshore	$2,632	$103	$320
	G-Filtration	$1,131	$136	$213
	M-Zero Discharge	$1,112	$136	$212
	M-Filtration	$474	$118	$140
Gulf 40	G-Zero Discharge	$2,935	$235	$450
	Onshore	$3,176	$125	$380
	G-Filtration	$1,335	$192	$276
	M-Zero Discharge	$1,510	$199	$297
	M-Filtration	$560	$171	$191
Gulf 58	G-Zero Discharge	$3,960	$324	$606
	Onshore	$1,587	$260	$352
	G-Filtration	$2,177	$280	$419
	M-Zero Discharge	$666	$237	$255
	M-Filtration			

Notes: No 58-well structures are projected for the shallow waters of the Gulf of Mexico.
G refers to granular filtrations costs for injection and filtration.
M refers to membrane filtrations costs for injection and filtration.

Source: ERG estimates.

TABLE 6-25

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
OIL AND GAS PLATFORMS
ATLANTIC AND PACIFIC

		Pollution Control Costs ($000, 1986 Dollars)		
Project	Scenario	Capital	O&M	Annualized
Atlantic 24	G-Zero Discharge	$6,297	$316	$824
	G-Filtration	$2,303	$221	$388
	M-Zero Discharge	$3,780	$277	$567
	M-Filtration	$966	$199	$251
Pacific 16	G-Zero Discharge	$4,365	$203	$718
	G-Filtration	$1,973	$152	$370
	M-Zero Discharge	$2,320	$172	$430
	M-Filtration	$826	$133	$207
Pacific 40	G-Zero Discharge	$7,376	$359	$1,181
	G-Filtration	$2,707	$255	$527
	M-Zero Discharge	$4,283	$317	$768
	M-Filtration	$1,137	$232	$316
Pacific 70	G-Zero Discharge	$12,668	$585	$1,881
	G-Filtration	$3,782	$398	$736
	M-Zero Discharge	$7,658	$527	$1,273
	M-Filtration	$1,592	$368	$468

Notes: G refers to granular filtrations costs for injection and filtration.
M refers to membrane filtrations costs for injection and filtration.

Source: ERG estimates.

TABLE 6-26

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
OIL AND GAS PLATFORMS AND OIL-ONLY PLATFORMS*
ALASKA

PROJECT	SCENARIO	Pollution Control Costs ($000, 1986 Dollars) Capital	O&M	Annualized
Cook Inlet	G-Zero Discharge	$13,462	$596	$1,593
	G-Filtration	$3,907	$369	$628
	M-Zero Discharge	$8,848	$541	$1,173
	M-Filtration	$1,643	$341	$421
Beaufort Gravel Is.	G-Zero Discharge	$36,655	$655	$3,347
	G-Filtration	$10,497	$653	$1,320
	M-Zero Discharge	$20,948	$623	$2,106
	M-Filtration	$4,426	$610	$816
Beaufort Platform	G-Zero Discharge	$36,300	$646	$3,351
	G-Filtration	$10,389	$630	$1,303
	M-Zero Discharge	$20,823	$615	$2,111
	M-Filtration	$4,380	$588	$799
Navarin	G-Zero Discharge	$36,656	$655	$3,347
	G-Filtration	$10,497	$653	$1,320
	M-Zero Discharge	$20,948	$623	$2,106
	M-Filtration	$4,426	$610	$816
Norton	G-Zero Discharge	$22,514	$681	$2,322
	G-Filtration	$8,193	$460	$1,008
	M-Zero Discharge	$11,725	$617	$1,411
	M-Filtration	$3,449	$428	$605

Notes: Cook Inlet project produces both oil and gas; all other projects are assumed to produce only oil.
G refers to granular filtrations costs for injection and filtration.
M refers to membrane filtrations costs for injection and filtration.
Source: ERG estimates.

TABLE 6-27

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
GAS-ONLY PLATFORMS

		Pollution Control Costs ($000, 1986 Dollars)		
Project	Scenario	Capital	O&M	Annualized
Gulf 1b	G-Zero Discharge	$1,644	$77	$228
	Onshore	$667	$41	$100
	G-Filtration	$146	$34	$45
	M-Zero Discharge	$1,508	$77	$215
	M-Filtration	$62	$34	$36
Gulf 4	G-Zero Discharge	$2,089	$82	$268
	Onshore	$1,675	$49	$199
	G-Filtration	$443	$38	$75
	M-Zero Discharge	$1,672	$79	$226
	M-Filtration	$188	$36	$50
Gulf 6	G-Zero Discharge	$2,139	$85	$272
	Onshore	$1,699	$54	$204
	G-Filtration	$471	$40	$79
	M-Zero Discharge	$1,690	$81	$227
	M-Filtration	$199	$37	$52
Gulf 12	G-Zero Discharge	$1,051	$57	$144
	Onshore	$1,748	$68	$217
	G-Filtration	$527	$46	$86
	M-Zero Discharge	$537	$49	$90
	M-Filtration	$223	$41	$54
Gulf 24	G-Zero Discharge	$1,195	$66	$151
	Onshore	$1,815	$83	$217
	G-Filtration	$635	$53	$94
	M-Zero Discharge	$588	$54	$91
	M-Filtration	$269	$45	$57
Pacific 16	G-Zero Discharge	$1,762	$67	$244
	G-Filtration	$1,011	$54	$152
	M-Zero Discharge	$795	$55	$129
	M-Filtration	$428	$46	$83
Atlantic 24	G-Zero Discharge	$2,013	$74	$52
	G-Filtration	$1,232	$59	$41
	M-Zero Discharge	$893	$59	$42
	M-Filtration	$521	$50	$35
Cook Inlet	G-Zero Discharge	$2,456	$54	$246
	G-Filtration	$1,540	$44	$162
	M-Zero Discharge	$1,056	$48	$126
	M-Filtration	$652	$39	$86

Note: G refers to granular filtration costs for filtration and injection.
M refers to membrane filtration costs for filtration and injection.
Source: ERG estimates.

TABLE 6-28

NSPS PRODUCED WATER
TOTAL CAPITAL AND ANNUAL O&M COSTS BY REGION
$MILLIONS, 1986 DOLLARS

Technology Cost	Effluent Control Option	Region	Restricted Activity Capital Costs	Restricted Activity Annual O&M Costs	Unrestricted Activity Capital Costs	Unrestricted Activity Annual O&M Costs
Membrane Filter	Zero Discharge	Gulf	$957.8	$66.3	$957.8	$66.3
		Pacific	$43.5	$3.1	$274.9	$20.3
		Alaska	$51.8	$1.8	$51.8	$1.8
		Atlantic	$0.0	$0.0	$15.8	$1.1
		Total	$1,053.0	$71.2	$1,300.3	$89.5
	All Filter	Gulf	$204.8	$44.3	$204.8	$44.3
		Pacific	$9.8	$2.2	$79.4	$15.0
		Alaska	$11.1	$1.6	$11.1	$1.6
		Atlantic	$0.0	$0.0	$5.5	$0.8
		Total	$225.7	$48.0	$300.9	$61.7
	4-Mile Filter; BPT Other	Gulf	$32.2	$6.8	$32.2	$6.8
		Pacific	$0.0	$0.0	$22.7	$4.6
		Alaska	$8.9	$1.2	$8.9	$1.2
		Atlantic	$0.0	$0.0	$0.0	$0.0
		Total	$41.1	$8.1	$63.8	$12.7
Granular Filter	Zero Discharge	Gulf	$1,416.0	$75.6	$1,416.0	$75.6
		Pacific	$72.8	$3.4	$485.0	$23.2
		Alaska	$89.2	$2.0	$89.2	$2.0
		Atlantic	$0.0	$0.0	$29.0	$1.3
		Total	$1,578.0	$81.0	$2,019.2	$102.0
	All Filter	Gulf	$485.0	$50.0	$485.0	$50.0
		Pacific	$23.2	$2.4	$189.0	$16.6
		Alaska	$26.4	$1.7	$26.4	$1.7
		Atlantic	$0.0	$0.0	$13.1	$1.0
		Total	$534.7	$54.0	$713.6	$69.3
	4-Mile Filter; BPT Other	Gulf	$76.2	$7.7	$76.2	$7.7
		Pacific	$0.0	$0.0	$54.1	$5.1
		Alaska	$21.0	$1.3	$21.0	$1.3
		Atlantic	$0.0	$0.0	$0.0	$0.0
		Total	$97.2	$9.0	$151.3	$14.1

Source: Environmental Protection Agency, Industrial Technology Division.

TABLE 6-29

ANNUALIZED COSTS OF NSPS PRODUCED WATER CONTROL OPTIONS
GRANULAR FILTER TECHNOLOGY COSTS
UNRESTRICTED ACTIVITY
$THOUSAND, 1986 DOLLARS

$21/bbl

	PRODUCED WATER CONTROL OPTIONS		
YEAR	ZERO DISCHARGE	ALL FILTER	4-Mile Filter; BPT Other
1985	$0	$0	$0
1986	$16,106	$7,555	$1,579
1987	$35,363	$16,650	$3,531
1988	$42,992	$20,446	$4,137
1989	$54,277	$25,748	$5,342
1990	$69,149	$32,615	$6,903
1991	$86,664	$40,691	$8,482
1992	$108,639	$50,712	$10,667
1993	$129,132	$60,325	$12,171
1994	$151,378	$70,499	$14,356
1995	$170,790	$79,701	$15,736
1996	$194,328	$90,343	$19,162
1997	$216,712	$100,780	$21,193
1998	$236,858	$110,212	$22,697
1999	$254,829	$118,483	$24,200
2000	$275,109	$127,500	$27,024

TABLE 6-30

ANNUALIZED COSTS OF NSPS PRODUCED WATER CONTROL OPTIONS
MEMBRANE FILTER TECHNOLOGY COSTS
UNRESTRICTED ACTIVITY
$THOUSAND, 1986 DOLLARS

$21/bbl

YEAR	PRODUCED WATER CONTROL OPTIONS: ZERO DISCHARGE	ALL FILTER	4-Mile Filter; BPT Other
1985	$0	$0	$0
1986	$12,184	$4,842	$1,009
1987	$26,504	$10,638	$2,252
1988	$31,637	$12,979	$2,621
1989	$39,795	$16,308	$3,373
1990	$50,455	$20,593	$4,334
1991	$63,351	$25,686	$5,343
1992	$79,763	$32,099	$6,721
1993	$94,825	$38,191	$7,680
1994	$111,488	$44,660	$9,058
1995	$125,638	$50,483	$9,929
1996	$142,715	$57,216	$12,071
1997	$159,137	$63,832	$13,347
1998	$173,902	$69,785	$14,306
1999	$187,326	$75,033	$15,266
2000	$202,249	$80,811	$17,041

The annualized costs for produced water disposal under the $21/bbl restricted development scenario are displayed in Tables 6-31 and 6-32 for the granular and membrane filter technology, respectively.

Tables 6-33 and 6-34 summarize the annualized costs in the year 2000 for:

- $21/bbl unrestricted development
- $21/bbl restricted development
- $15/bbl restricted development
- $32/bbl unrestricted development

Table 6-33 represents the costs with granular filtration, while Table 6-34 represents the costs with membrane filtration.

Note that the costs for the 4-Mile Filter; BPT Other option range from $12 million to $51 million (1986 dollars) with granular filtration and from $8 million to $32 million with membrane filtration.

The per-project annualized costs are lower for NSPS than BAT because it is less expensive to design additional pollution control requirements into a new platform than it is to retrofit an existing platform. This, coupled with the fact that there are approximately two-and-one-half times as many existing platforms as there are projected platforms, explains why the total annualized costs for BAT-produced water pollution control options are several times higher than total annualized costs for NSPS options.

6.4 COMBINED COST OF SELECTED REGULATORY OPTIONS

Six combinations of options have been chosen in order to analyze the impacts of the increased pollution control on the three effluents. These combinations are:

Drilling Fluids and Drill Cuttings:	4-Mile Barge; 1,1 Other[1]
Produced Water - BAT:	4-Mile Filter; BPT Other (granular filter costs)
Produced Water - NSPS:	4-Mile Filter; BPT Other (granular filter costs)

[1]Under the 4-Mile Barge; 1,1 Other option Alaska is exempt from the barging requirement, but must comply with the 1,1 All restrictions.

TABLE 6-31

ANNUALIZED COSTS OF NSPS PRODUCED WATER CONTROL OPTIONS
GRANULAR FILTER TECHNOLOGY COSTS
RESTRICTED ACTIVITY
$THOUSAND, 1986 DOLLARS

$21/bbl

YEAR	PRODUCED WATER CONTROL OPTIONS		
	ZERO DISCHARGE	ALL FILTER	4-Mile Filter; BPT Other
1985	$0	$0	$0
1986	$13,257	$6,197	$1,052
1987	$30,135	$14,077	$2,477
1988	$34,441	$16,297	$2,556
1989	$41,466	$19,649	$3,234
1990	$49,473	$23,358	$3,740
1991	$65,302	$30,443	$4,792
1992	$83,794	$38,558	$5,923
1993	$98,307	$45,347	$6,900
1994	$114,869	$52,891	$8,031
1995	$128,596	$59,463	$8,883
1996	$146,449	$67,475	$11,255
1997	$161,093	$74,325	$12,232
1998	$175,311	$80,975	$13,208
1999	$188,534	$86,992	$14,185
2000	$206,208	$94,802	$16,481

TABLE 6-32

ANNUALIZED COSTS OF NSPS PRODUCED WATER CONTROL OPTIONS
MEMBRANE FILTER TECHNOLOGY COSTS
RESTRICTED ACTIVITY
$THOUSANDS, 1986 DOLLARS

$21/bbl

YEAR	PRODUCED WATER CONTROL OPTIONS: ZERO DISCHARGE	ALL FILTER	4-Mile Filter; BPT Other
1985	$0	$0	$0
1986	$10,390	$4,044	$693
1987	$23,249	$9,151	$1,619
1988	$26,286	$10,569	$1,671
1989	$31,711	$12,743	$2,107
1990	$37,972	$15,155	$2,435
1991	$49,916	$19,710	$3,128
1992	$64,115	$24,978	$3,873
1993	$75,374	$29,397	$4,516
1994	$88,406	$34,310	$5,261
1995	$98,925	$38,578	$5,815
1996	$112,371	$43,755	$7,324
1997	$123,785	$48,213	$7,967
1998	$134,790	$52,528	$8,610
1999	$145,222	$56,455	$9,253
2000	$158,479	$61,517	$10,712

TABLE 6-33

ANNUALIZED COST OF POLLUTION CONTROL IN THE YEAR 2000
NSPS PRODUCED WATER
GRANULAR FILTRATION TECHNOLOGY COSTS
$MILLIONS, 1986 DOLLARS

	Annualized Regulatory Costs			
Option	$21/bbl Unrestricted	$21/bbl Restricted	$15/bbl Restricted	$32/bbl Unrestricted
Zero Discharge	$275	$206	$170	$375
All Filter	$128	$95	$80	$168
4-Mile Filter; BPT Other	$27	$16	$12	$51

Source: ERG estimates.

TABLE 6-34

ANNUALIZED COST OF POLLUTION CONTROL IN THE YEAR 2000
NSPS PRODUCED WATER
MEMBRANE FILTRATION TECHNOLOGY COSTS
$MILLIONS, 1986 DOLLARS

	Annualized Regulatory Costs			
Option	$21/bbl Unrestricted	$21/bbl Restricted	$15/bbl Restricted	$32/bbl Unrestricted
Zero Discharge	$202	$158	$135	$270
All Filter	$81	$62	$53	$108
4-Mile Filter; BPT Other	$17	$11	$8	$32

Source: ERG estimates.

- Drilling Fluids and Drill Cuttings: 4-Mile Barge; 1,1 Other[1]
  Produced Water - BAT: Zero Discharge (granular filter costs)
  Produced Water - NSPS: Zero Discharge (granular filter costs)

- Drilling Fluids and Drill Cuttings: 4-Mile Barge; 1,1 Other[1]
  Produced Water - BAT: All Filter (granular filter costs)
  Produced Water - NSPS: All Filter (granular filter costs)

- Drilling Fluids and Drill Cuttings: 4-Mile Barge; 1,1 Other[1]
  Produced Water - BAT: All Filter (membrane filter costs)
  Produced Water - NSPS: All Filter (membrane filter costs)

- Drilling Fluids and Drill Cuttings: 4-Mile Barge; 1,1 Other[1]
  Produced Water - BAT: BPT All
  Produced Water - NSPS: BPT All

- Drilling Fluids and Drill Cuttings: 4-Mile Barge; 1,1 Other[1]
  Produced Water - BAT: 4-Mile Filter; BPT Other (membrane filter costs)
  Produced Water - NSPS: 4-Mile Filter; BPT Other (membrane filter costs)

These combinations are referred to as regulatory packages A through F, respectively. Table 6-35 presents the combined cost of each package for the $21/bbl scenario. Two sets of costs are presented for each regulatory package (unrestricted and restricted development scenario). The costs presented are the annualized costs in 2000 for NSPS effluents. The cost for offshore package F (4-Mile Barge; 1,1 All and 4-Mile Filter; BPT Other with membrane filter costs) ranges from $54 to $80 million (1986 dollars) depending upon the level of development. The costs range from $30 million for regulatory package E to $1,081 million (1986 dollars) for regulatory package B under restricted development, and from $50 million to $1,170 million for the same options under unrestricted development. Note that costs drop from $657 to $282 million or from $605 to $242 million when the use of granular filtration is replaced by membrane filtration in packages C and D, respectively. Similarly, the costs drop from $118 to $80 million or from $88 to $54 million when membrane filtration is assumed for Option F.

Tables 6-36 through 6-39 summarize the costs for the regulatory packages by region. Note that the costs for the Gulf (Table 6-36) and Alaska (Table 6-37) are the same for both restricted and unrestricted development scenarios.

TABLE 6-35

COMBINED COST OF SELECTED REGULATORY PACKAGES
$MILLIONS, 1986 DOLLARS

$21/bbl

Regulatory Package	Effluent	Effluent Control Option	Annualized Cost in the Year 2000 Restricted	Annualized Cost in the Year 2000 Unrestricted
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	4-Mile Filter; BPT Other	$41	$41
	Produced Water - NSPS	4-Mile Filter; BPT Other	$16	$27
	Combined Cost		$88	$118
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	Zero Discharge	$845	$845
	Produced Water - NSPS	Zero Discharge	$206	$275
	Combined Cost		$1,081	$1,170
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	All Filter	$480	$480
	Produced Water - NSPS	All Filter	$95	$128
	Combined Cost		$605	$657
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	All Filter - Membrane	$151	$151
	Produced Water - NSPS	All Filter - Membrane	$62	$81
	Combined Cost		$242	$282
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	BPT All	$0	$0
	Produced Water - NSPS	BPT All	$0	$0
	Combined Cost		$30	$50
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$50
	Produced Water - BAT	4-Mile Filter; BPT Other - Membrane	$13	$13
	Produced Water - NSPS	4-Mile Filter; BPT Other - Membrane	$11	$17
	Combined Cost		$54	$80

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology.

Entries may not sum due to independent rounding.

Source: ERG estimates.

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TABLE 6-36

COMBINED COST OF SELECTED REGULATORY PACKAGES - GULF REGION
$MILLIONS, 1986 DOLLARS

$21/bbl

Regulatory Package	Effluent	Effluent Control Option	Annualized Cost in the Year 2000 Restricted	Annualized Cost in the Year 2000 Unrestricted
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$29.5	$29.5
	Produced Water - BAT	4-Mile Filter; BPT Other	$24.3	$24.3
	Produced Water - NSPS	4-Mile Filter; BPT Other	$13.8	$13.8
	Combined Cost		$67.6	$67.6
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$29.5	$29.5
	Produced Water - BAT	Zero Discharge	$776.8	$776.8
	Produced Water - NSPS	Zero Discharge	$186.6	$186.6
	Combined Cost		$992.9	$992.9
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$29.5	$29.5
	Produced Water - BAT	All Filter	$438.1	$438.1
	Produced Water - NSPS	All Filter	$86.8	$86.8
	Combined Cost		$554.4	$554.4
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$29.5	$29.5
	Produced Water - BAT	All Filter - Membrane	$139.6	$139.6
	Produced Water - NSPS	All Filter - Membrane	$56.6	$56.6
	Combined Cost		$225.7	$2[illegible]
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$29.5	$29.5
	Produced Water - BAT	BPT All	$0.0	$0.0
	Produced Water - NSPS	BPT All	$0.0	$0.0
	Combined Cost		$29.5	$29.5
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$29.5	$29.5
	Produced Water - BAT	4-Mile Filter; BPT Other - Membrane	$8.8	$8.8
	Produced Water - NSPS	4-Mile Filter; BPT Other - Membrane	$9.1	$9.1
	Combined Cost		$47.4	$47.4

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology.

Entries may not sum due to independent rounding.

Source: ERG estimates.

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TABLE 6-37

COMBINED COST OF SELECTED REGULATORY PACKAGES - ALASKA REGION
$MILLIONS, 1986 DOLLARS

$21/bbl

Regulatory Package	Effluent	Effluent Control Option	Annualized Cost in the Year 2000 Restricted	Annualized Cost in the Year 2000 Unrestricted
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.3	$0.3
	Produced Water - BAT	4-Mile Filter; BPT Other	$0.0	$0.0
	Produced Water - NSPS	4-Mile Filter; BPT Other	$2.6	$2.6
	Combined Cost		$3.0	$3.0
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.3	$0.3
	Produced Water - BAT	Zero Discharge	$0.0	$0.0
	Produced Water - NSPS	Zero Discharge	$8.5	$8.5
	Combined Cost		$8.9	$8.9
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.3	$0.3
	Produced Water - BAT	All Filter	$0.0	$0.0
	Produced Water - NSPS	All Filter	$3.4	$3.4
	Combined Cost		$3.8	$3.8
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.3	$0.3
	Produced Water - BAT	All Filter - Membrane	$0.0	$0.0
	Produced Water - NSPS	All Filter - Membrane	$2.1	$2.1
	Combined Cost		$2.5	$2.5
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.3	$0.3
	Produced Water - BAT	BPT All	$0.0	$0.0
	Produced Water - NSPS	BPT All	$0.0	$0.0
	Combined Cost		$0.3	$0.3
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.3	$0.3
	Produced Water - BAT	4-Mile Filter; BPT Other - Membrane	$0.0	$0.0
	Produced Water - NSPS	4-Mile Filter; BPT Other - Membrane	$1.6	$1.6
	Combined Cost		$2.0	$2.0

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology.

Entries may not sum due to independent rounding.

Source: ERG estimates.

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TABLE 6-38

COMBINED COST OF SELECTED REGULATORY PACKAGES - PACIFIC REGION
$MILLIONS, 1986 DOLLARS

$21/bbl

Regulatory Package	Effluent	Effluent Control Option	Annualized Cost in the Year 2000 Restricted	Annualized Cost in the Year 2000 Unrestricted
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.1	$19.3
	Produced Water - BAT	4-Mile Filter; BPT Other	$17.0	$17.0
	Produced Water - NSPS	4-Mile Filter; BPT Other	$0.0	$10.5
	Combined Cost		$17.1	$46.8
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.1	$19.3
	Produced Water - BAT	Zero Discharge	$67.9	$67.9
	Produced Water - NSPS	Zero Discharge	$11.1	$77.2
	Combined Cost		$79.0	$164.4
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.1	$19.3
	Produced Water - BAT	All Filter	$42.0	$42.0
	Produced Water - NSPS	All Filter	$4.5	$35.9
	Combined Cost		$46.6	$97.1
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.1	$19.3
	Produced Water - BAT	All Filter - Membrane	$11.2	$11.2
	Produced Water - NSPS	All Filter - Membrane	$2.8	$21.2
	Combined Cost		$14.1	[illegible]
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.1	$19.3
	Produced Water - BAT	BPT All	$0.0	$0.0
	Produced Water - NSPS	BPT All	$0.0	$0.0
	Combined Cost		$0.1	$19.3
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.1	$19.3
	Produced Water - BAT	4-Mile Filter; BPT Other - Membrane	$4.1	$4.1
	Produced Water - NSPS	4-Mile Filter; BPT Other - Membrane	$0.0	$6.3
	Combined Cost		$4.2	$29.7

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology.

Entries may not sum due to independent rounding.

Source: ERG estimates.

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TABLE 6-39

COMBINED COST OF SELECTED REGULATORY PACKAGES - ATLANTIC REGION
$MILLIONS, 1986 DOLLARS

$21/bbl

Regulatory Package	Effluent	Effluent Control Option	Annualized Cost in the Year 2000: Restricted	Annualized Cost in the Year 2000: Unrestricted
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.0	$0.8
	Produced Water - BAT	4-Mile Filter; BPT Other	$0.0	$0.0
	Produced Water - NSPS	4-Mile Filter; BPT Other	$0.0	$0.0
	Combined Cost		$0.0	$0.8
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.0	$0.8
	Produced Water - BAT	Zero Discharge	$0.0	$0.0
	Produced Water - NSPS	Zero Discharge	$0.0	$2.7
	Combined Cost		$0.0	$3.6
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.0	$0.8
	Produced Water - BAT	All Filter	$0.0	$0.0
	Produced Water - NSPS	All Filter	$0.0	$1.4
	Combined Cost		$0.0	$2.2
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.0	$0.8
	Produced Water - BAT	All Filter - Membrane	$0.0	$0.0
	Produced Water - NSPS	All Filter - Membrane	$0.0	$0.9
	Combined Cost		$0.0	$1.8
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.0	$0.8
	Produced Water - BAT	BPT All	$0.0	$0.0
	Produced Water - NSPS	BPT All	$0.0	$0.0
	Combined Cost		$0.0	$0.8
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$0.0	$0.8
	Produced Water - BAT	4-Mile Filter; BPT Other - Membrane	$0.0	$0.0
	Produced Water - NSPS	4-Mile Filter; BPT Other - Membrane	$0.0	$0.0
	Combined Cost		$0.0	$0.8

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology.

Entries may not sum due to independent rounding.

Source: ERG estimates.

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The costs for the Pacific (Table 6-38) and the Atlantic (Table 6-39) do vary according to the assumptions on the level of development. In all cases, the Gulf of Mexico bears the majority of the costs because it has the majority of the projected development.

6.5 REFERENCES

FR 1985. "Draft General NPDES Permit for Offshore Oil and Gas Exploration Activities Off Southern California," Federal Register volume 50, 22 August 1985, 34036 ff.

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FR 1988b. "Final NPDES General Permit for Offshore Oil and Gas Operations on the Outer Continental Shelf of Alaska: Beaufort Sea II and Chukchi Sea," Federal Register volume 53, 28 September 1988, 37846 ff.

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Kaplan 1989b. "Agreement on Price Increase for 1,2 and 1,3 Barite," memorandum to Offshore file from Maureen F. Kaplan, Eastern Research Group, Inc., 20 December 1989.

Kaplan and Meyers 1987. "The Adequacy of Available Foreign and Domestic Supplies of Barite That Meet Revised Limitations for Cadmium and Mercury Content," memorandum from Maureen F. Kaplan and David Meyers, Eastern Research Group, Inc., to Ann Watkins, EPA, 4 November 1987.

WHA 1984. "Potential Impacts of Proposed EPA BAT/NSPS Standards for Produced Water Discharges from Offshore Oil and Gas Extraction Industry," Walk, Haydel Associates, January 1984, Table 2-7.

SECTION SEVEN

IMPACTS ON REPRESENTATIVE FACILITIES

New and existing offshore projects incur additional costs for increased pollution control of drilling and production wastes. Section Five describes the offshore oil and gas projects used in this analysis and presents the results of the base case simulations. Section Six describes incremental costs of compliance under the various pollution control options. In this section, the incremental costs are incorporated into the economic simulations. By examining the change in the financial summary statistics for each project, ERG assesses the economic impacts of the various approaches. Section Seven is organized according to effluent and type of regulation (e.g., BAT or NSPS). Drilling wastes are discussed in Section 7.1. Production wastes are discussed in Section 7.2 for BAT projects and in Section 7.3 for NSPS projects. Section 7.4 discusses the combined effect of selected pollution control options.

7.1 DRILLING FLUIDS AND DRILL CUTTINGS

The incremental costs of pollution control are incurred by every exploratory, delineation, and development well. Tables 7-1 and 7-2 list the impacts for the oil and gas projects for the Gulf of Mexico. Table 7-3 lists the impacts for the oil and gas projects in the Pacific and the Atlantic. Oil-producing projects in Alaska and their impacts are presented in Table 7-4. Impacts on gas-only projects are presented in Table 7-5 for the Gulf of Mexico and in Table 7-6 for all other regions.

7.1.1 Financial Summary Statistics

<u>PV of Total Production</u>: The present value (PV) of total production is given in terms of barrels-of-oil equivalent (BOE) and is related to the economic lifetime of the project. There is <u>no change</u> in this parameter for any project under any regulatory scenario.

<u>Corporate Cost per BOE</u>: The corporate cost of production changes less than 2.3 percent or 47 cents per BOE for <u>all</u> pollution control options. The

TABLE 7-1

POLLUTION CONTROL OPTIONS FOR DRILLING FLUIDS AND DRILL CUTTINGS
MODEL PROJECT IMPACTS - OIL AND GAS PLATFORMS

GULF OF MEXICO

		PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost Per BOE		Production Cost Per BOE		Net Present Value ($1000)		Internal Rate Of Return		Years Of Production	
PROJECT	SCENARIO	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Gulf 1b	Baseline	1,159,301		$21.16		$13.71		$654		9.5%		20	
Gulf 1b	Zero Discharge	1,159,301	0.0%	$21.63	2.2%	$14.39	5.0%	$110	-83.1%	8.2%	-13.2%	20	0.0%
Gulf 1b	4-Mile Barge; 1,1 Other	1,159,301	0.0%	$21.23	0.3%	$13.81	0.7%	$579	-11.5%	9.3%	-2.0%	20	0.0%
Gulf 1b	4-Mile Barge; 5,3 Other	1,159,301	0.0%	$21.21	0.2%	$13.78	0.5%	$597	-8.7%	9.4%	-0.9%	20	0.0%
Gulf 1b	1,1 All	1,159,301	0.0%	$21.18	0.1%	$13.74	0.2%	$632	-3.4%	9.4%	-0.6%	20	0.0%
Gulf 1b	5,3 All	1,159,301	0.0%	$21.17	0.0%	$13.71	0.0%	$652	-0.3%	9.5%	-0.0%	20	0.0%
Gulf 4	Baseline	4,301,632		$18.09		$8.98		$15,649		21.4%		21	
Gulf 4	Zero Discharge	4,301,632	0.0%	$18.35	1.5%	$9.35	4.1%	$14,518	-7.2%	19.9%	-6.8%	21	0.0%
Gulf 4	4-Mile Barge; 1,1 Other	4,301,632	0.0%	$18.13	0.2%	$9.03	0.6%	$15,492	-1.0%	21.2%	-0.8%	21	0.[illegible]
Gulf 4	4-Mile Barge; 5,3 Other	4,301,632	0.0%	$18.12	0.2%	$9.02	0.5%	$15,530	-0.8%	21.2%	-0.8%	21	0.[illegible]
Gulf 4	1,1 All	4,301,632	0.0%	$18.10	0.1%	$8.99	0.2%	$15,603	-0.3%	21.3%	-0.3%	21	0.0%
Gulf 4	5,3 All	4,301,632	0.0%	$18.09	0.0%	$8.98	0.0%	$15,645	-0.0%	21.4%	-0.0%	21	0.0%
Gulf 6	Baseline	6,452,448		$17.71		$8.40		$25,909		23.1%		21	
Gulf 6	Zero Discharge	6,452,448	0.0%	$17.96	1.4%	$8.74	4.1%	$24,327	-6.1%	21.7%	-6.3%	21	0.0%
Gulf 6	4-Mile Barge; 1,1 Other	6,452,448	0.0%	$17.75	0.2%	$8.45	0.6%	$25,690	-0.8%	22.9%	-1.0%	21	0.0%
Gulf 6	4-Mile Barge; 5,3 Other	6,452,448	0.0%	$17.74	0.2%	$8.43	0.4%	$25,743	-0.6%	23.0%	-0.6%	21	0.0%
Gulf 6	1,1 All	6,452,448	0.0%	$17.72	0.1%	$8.41	0.2%	$25,845	-0.2%	23.1%	-0.3%	21	0.0%
Gulf 6	5,3 All	6,452,448	0.0%	$17.71	0.0%	$8.40	0.0%	$25,904	-0.0%	23.1%	-0.0%	21	0.0%
Gulf 12	Baseline	9,611,069		$18.23		$8.95		$33,610		20.1%		19	
Gulf 12	Zero Discharge	9,611,069	0.0%	$18.46	1.3%	$9.27	3.6%	$31,369	-6.7%	18.9%	-5.9%	19	0.0%
Gulf 12	4-Mile Barge; 1,1 Other	9,611,069	0.0%	$18.26	0.2%	$9.00	0.5%	$33,300	-0.9%	19.9%	-1.0%	19	0.0%
Gulf 12	4-Mile Barge; 5,3 Other	9,611,069	0.0%	$18.25	0.1%	$8.98	0.3%	$33,375	-0.7%	20.0%	-0.5%	19	0.0%
Gulf 12	1,1 All	9,611,069	0.0%	$18.24	0.1%	$8.96	0.1%	$33,519	-0.3%	20.0%	-0.2%	19	0.0%
Gulf 12	5,3 All	9,611,069	0.0%	$18.23	0.0%	$8.95	0.0%	$33,603	-0.0%	20.1%	-0.0%	19	0.0%

Source: ERG estimates.

TABLE 7-2

POLLUTION CONTROL OPTIONS FOR DRILLING FLUIDS AND DRILL CUTTINGS
MODEL PROJECT IMPACTS - OIL AND GAS PLATFORMS AND OIL-ONLY PLATFORMS

GULF OF MEXICO - Continued

		PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost Per BOE		Production Cost Per BOE		Net Present Value ($1000)		Internal Rate Of Return		Years Of Production	
PROJECT	SCENARIO	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Gulf 24	Baseline	17,470,722		$16.26		$8.13		$95,532		27.3%		21	
Gulf 24	Zero Discharge	17,470,722	0.0%	$16.47	1.3%	$8.42	3.6%	$91,824	-3.9%	25.9%	-5.0%	21	0.0%
Gulf 24	4-Mile Barge; 1,1 Other	17,470,722	0.0%	$16.29	0.2%	$8.17	0.4%	$95,019	-0.5%	27.1%	-0.8%	21	0.0%
Gulf 24	4-Mile Barge; 5,3 Other	17,470,722	0.0%	$16.28	0.1%	$8.16	0.3%	$95,144	-0.4%	27.2%	-0.4%	21	0.0%
Gulf 24	1,1 All	17,470,722	0.0%	$16.27	0.1%	$8.15	0.1%	$95,382	-0.2%	27.2%	-0.2%	21	0.0%
Gulf 24	5,3 All	17,470,722	0.0%	$16.26	0.0%	$8.14	0.0%	$95,520	-0.0%	27.3%	-0.0%	21	0.0%
Gulf 40	Baseline	29,889,385		$16.04		$7.74		$169,856		25.2%		23	
Gulf 40	Zero Discharge	29,889,385	0.0%	$16.24	1.3%	$8.02	3.6%	$163,806	-3.6%	24.1%	-4.4%	23	0.0%
Gulf 40	4-Mile Barge; 1,1 Other	29,889,385	0.0%	$16.07	0.2%	$7.78	0.5%	$169,018	-0.5%	25.1%	-0.6%	23	0.0%
Gulf 40	4-Mile Barge; 5,3 Other	29,889,385	0.0%	$16.06	0.1%	$7.77	0.3%	$169,222	-0.4%	25.1%	-0.6%	23	0.0%
Gulf 40	1,1 All	29,889,385	0.0%	$16.05	0.1%	$7.76	0.1%	$169,610	-0.1%	25.2%	-0.2%	23	0.0%
Gulf 40	5,3 All	29,889,385	0.0%	$16.04	0.0%	$7.75	0.0%	$169,835	-0.0%	25.2%	-0.0%	23	0.0%
Gulf 58	Baseline	35,194,925		$16.53		$7.90		$182,742		20.7%		25	
Gulf 58	Zero Discharge	35,194,925	0.0%	$16.74	1.2%	$8.17	3.4%	$175,575	-3.9%	19.9%	-3.9%	25	0.0%
Gulf 58	4-Mile Barge; 1,1 Other	35,194,925	0.0%	$16.56	0.2%	$7.94	0.5%	$181,750	-0.5%	20.6%	-0.6%	25	0.0%
Gulf 58	4-Mile Barge; 5,3 Other	35,194,925	0.0%	$16.55	0.1%	$7.93	0.4%	$181,992	-0.4%	20.6%	-0.6%	25	0.0%
Gulf 58	1,1 All	35,194,925	0.0%	$16.54	0.0%	$7.91	0.1%	$182,452	-0.2%	20.7%	-0.2%	25	0.0%
Gulf 58	5,3 All	35,194,925	0.0%	$16.53	0.0%	$7.90	0.0%	$182,718	-0.0%	20.7%	-0.0%	25	0.0%

Source: ERG estimates.

TABLE 7-3

POLLUTION CONTROL OPTIONS FOR DRILLING FLUIDS AND DRILL CUTTINGS
MODEL PROJECT IMPACTS - OIL AND GAS PLATFORMS

ATLANTIC AND PACIFIC

PROJECT	SCENARIO	PV of Total Production (Bbls-of-oil equivalent) Data	% Change	Corporate Cost Per BOE Data	% Change	Production Cost Per BOE Data	% Change	Net Present Value ($1000) Data	% Change	Internal Rate Of Return Data	% Change	Years Of Production Data	% Change
Atlantic 24	Baseline	25,801,198		$19.05		$16.52		($66,121)		2.6%		21	
Atlantic 24	Zero Discharge	25,801,198	0.0%	$19.34	1.5%	$16.92	2.5%	($73,721)	-11.5%	2.1%	-18.7%	21	0.0%
Atlantic 24	4-Mile Barge; 1,1 Other	25,801,198	0.0%	$19.08	0.2%	$16.56	0.3%	($66,991)	-1.3%	2.5%	-2.2%	21	0.0%
Atlantic 24	4-Mile Barge; 5,3 Other	25,801,198	0.0%	$19.08	0.1%	$16.55	0.2%	($66,810)	-1.0%	2.5%	-1.7%	21	0.0%
Atlantic 24	1,1 All	25,801,198	0.0%	$19.08	0.2%	$16.56	0.3%	($66,991)	-1.3%	2.5%	-2.2%	21	0.0%
Atlantic 24	5,3 All	25,801,198	0.0%	$19.08	0.1%	$16.55	0.2%	($66,810)	-1.0%	2.5%	-1.7%	21	0.0%
Pacific 16	Baseline	11,449,953		$12.96		$7.19		$45,337		39.4%		9	
Pacific 16	Zero Discharge	11,449,953	0.0%	$13.19	1.8%	$7.51	4.4%	$42,686	-5.8%	36.1%	-8.2%	9	0.0%
Pacific 16	4-Mile Barge; 1,1 Other	11,449,953	0.0%	$13.04	0.6%	$7.29	1.4%	$44,488	-1.9%	38.3%	-2.7%	9	0.0%
Pacific 16	4-Mile Barge; 5,3 Other	11,449,953	0.0%	$13.04	0.6%	$7.29	1.4%	$44,488	-1.9%	38.3%	-2.7%	9	0.0%
Pacific 16	1,1 All	11,449,953	0.0%	$12.97	0.0%	$7.20	0.1%	$45,295	-0.1%	39.3%	-0.1%	9	0.0%
Pacific 16	5,3 All	11,449,953	0.0%	$12.96	0.0%	$7.19	0.0%	$45,337	0.0%	39.4%	0.0%	9	0.0%
Pacific 40	Baseline	20,252,704		$12.89		$6.05		$81,686		33.8%		10	
Pacific 40	Zero Discharge	20,252,704	0.0%	$13.09	1.6%	$6.32	4.5%	$77,529	-5.1%	31.5%	-6.8%	10	0.0%
Pacific 40	4-Mile Barge; 1,1 Other	20,252,704	0.0%	$12.95	0.5%	$6.13	1.4%	$80,355	-1.6%	33.1%	-2.2%	10	0.0%
Pacific 40	4-Mile Barge; 5,3 Other	20,252,704	0.0%	$12.95	0.5%	$6.13	1.4%	$80,355	-1.6%	33.1%	-2.2%	10	0.0%
Pacific 40	1,1 All	20,252,704	0.0%	$12.89	0.0%	$6.05	0.1%	$81,620	-0.1%	33.8%	-0.1%	10	0.0%
Pacific 40	5,3 All	20,252,704	0.0%	$12.89	0.0%	$6.05	0.0%	$81,686	0.0%	33.8%	0.0%	10	0.0%
Pacific 70	Baseline	29,277,100		$12.38		$5.94		$132,919		29.5%		12	
Pacific 70	Zero Discharge	29,277,100	0.0%	$12.58	1.6%	$6.19	4.3%	$127,198	-4.3%	27.8%	-5.7%	12	0.0%
Pacific 70	4-Mile Barge; 1,1 Other	29,277,100	0.0%	$12.44	0.5%	$6.02	1.4%	$131,087	-1.4%	29.0%	-1.7%	12	0.0%
Pacific 70	4-Mile Barge; 5,3 Other	29,277,100	0.0%	$12.44	0.5%	$6.02	1.4%	$131,087	-1.4%	29.0%	-1.7%	12	0.0[illegible]
Pacific 70	1,1 All	29,277,100	0.0%	$12.38	0.0%	$5.94	0.1%	$132,828	-0.1%	29.5%	-0.1%	12	0.0[illegible]
Pacific 70	5,3 All	29,277,100	0.0%	$12.38	0.0%	$5.94	0.0%	$132,919	0.0%	29.5%	0.0%	12	0.0%

Note: There is no activity within 4 miles of shore for the Atlantic, so only the Zero Discharge, 1,1 All, and 5,3 All options are applicable.
For the Pacific, the 4-Mile Barge scenarios refer to the $21/bbl unrestricted development scenario.
There is no activity within 4 miles for the Pacific under the $21/bbl restricted development scenario. The impacts, then, revert to the 1,1 All and 5,3 All options.

Source: ERG estimates.

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POLLUTION CONTROL OPTIONS FOR DRILLING FLUIDS AND DRILL CUTTINGS
MODEL PROJECT IMPACTS - OIL AND GAS PLATFORMS AND OIL-ONLY PLATFORMS*

ALASKA

		PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost Per BOE		Production Cost Per BOE		Net Present Value ($1000)		Internal Rate Of Return		Years Of Production	
PROJECT	SCENARIO	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Cook Inlet	Baseline	61,707,003		$13.22		$4.18		$357,708		39.0%		30	
Cook Inlet	Zero Discharge	61,707,003	0.0%	$13.29	0.5%	$4.28	2.3%	$353,300	-1.2%	37.9%	-2.8%	30	0.0%
Cook Inlet	4-Mile Barge; 1,1 Other	61,707,003	0.0%	$13.27	0.4%	$4.26	1.8%	$354,263	-1.0%	38.2%	-2.2%	30	0.0%
Cook Inlet	4-Mile Barge; 5,3 Other	61,707,003	0.0%	$13.27	0.4%	$4.26	1.8%	$354,263	-1.0%	38.2%	-2.2%	30	0.0%
Cook Inlet	1,1 All	61,707,003	0.0%	$13.22	0.0%	$4.19	0.2%	$357,328	-0.1%	38.9%	-0.2%	30	0.0%
Cook Inlet	5,3 All	61,707,003	0.0%	$13.22	0.0%	$4.19	0.1%	$357,423	-0.1%	39.0%	-0.2%	30	0.0%
Beaufort G	Baseline	73,172,498		$12.19		$5.53		$191,157		18.4%		30	
Beaufort G	Zero Discharge	73,172,498	0.0%	$12.26	0.6%	$5.63	1.7%	$185,740	-2.8%	18.0%	-2.6%	30	0.0%
Beaufort G	4-Mile Barge; 1,1 Other	73,172,498	0.0%	$12.25	0.5%	$5.61	1.4%	$186,924	-2.2%	18.1%	-2.0%	30	0.0%
Beaufort G	4-Mile Barge; 5,3 Other	73,172,498	0.0%	$12.25	0.5%	$5.61	1.4%	$186,924	-2.2%	18.1%	-2.0%	30	0.0%
Beaufort G	1,1 All	73,172,498	0.0%	$12.19	0.1%	$5.54	0.2%	$190,690	-0.2%	18.4%	-0.2%	30	0.0%
Beaufort G	5,3 All	73,172,498	0.0%	$12.19	0.0%	$5.54	0.1%	$190,807	-0.2%	18.4%	-0.2%	30	0.0%
Beaufort P	Baseline	67,592,103		$11.50		$6.33		$223,074		20.5%		28	
Beaufort P	Zero Discharge	67,592,103	0.0%	$11.58	0.7%	$6.43	1.6%	$217,969	-2.3%	20.0%	-2.4%	28	0.0%
Beaufort P	4-Mile Barge; 1,1 Other	67,592,103	0.0%	$11.56	0.5%	$6.41	1.2%	$219,084	-1.8%	20.1%	-1.8%	28	0.0%
Beaufort P	4-Mile Barge; 5,3 Other	67,592,103	0.0%	$11.56	0.5%	$6.41	1.2%	$219,084	-1.8%	20.1%	-1.8%	28	0.0%
Beaufort P	1,1 All	67,592,103	0.0%	$11.51	0.1%	$6.34	0.1%	$222,634	-0.2%	20.5%	-0.2%	28	0.0%
Beaufort P	5,3 All	67,592,103	0.0%	$11.50	0.0%	$6.34	0.1%	$222,744	-0.1%	20.5%	-0.2%	28	0.0%
Navarin	Baseline	73,172,498		$12.41		$7.47		$175,208		15.2%		30	
Navarin	Zero Discharge	73,172,498	0.0%	$12.48	0.6%	$7.56	1.3%	$169,792	-3.1%	14.9%	-2.0%	30	0.0%
Navarin	4-Mile Barge; 1,1 Other	73,172,498	0.0%	$12.46	0.5%	$7.54	1.0%	$170,975	-2.4%	14.9%	-1.6%	30	0.0%
Navarin	4-Mile Barge; 5,3 Other	73,172,498	0.0%	$12.46	0.5%	$7.54	1.0%	$170,975	-2.4%	14.9%	-1.6%	30	0.0%
Navarin	1,1 All	73,172,498	0.0%	$12.41	0.1%	$7.47	0.1%	$174,741	-0.3%	15.1%	-0.2%	30	0.0%
Navarin	5,3 All	73,172,498	0.0%	$12.41	0.0%	$7.47	0.1%	$174,858	-0.2%	15.1%	-0.1%	30	0.0%
Norton	Baseline	61,740,561		$11.22		$6.09		$220,856		24.1%		27	
Norton	Zero Discharge	61,740,561	0.0%	$11.30	0.7%	$6.19	1.7%	$216,060	-2.2%	23.5%	-2.7%	27	0.0%
Norton	4-Mile Barge; 1,1 Other	61,740,561	0.0%	$11.28	0.5%	$6.17	1.3%	$217,108	-1.7%	23.6%	-2.1%	27	0.0%
Norton	4-Mile Barge; 5,3 Other	61,740,561	0.0%	$11.28	0.5%	$6.17	1.3%	$217,108	-1.7%	23.6%	-2.1%	27	0.0%
Norton	1,1 All	61,740,561	0.0%	$11.23	0.1%	$6.09	0.1%	$220,443	-0.2%	24.1%	-0.2%	27	0.0%
Norton	5,3 All	61,740,561	0.0%	$11.23	0.0%	$6.09	0.1%	$220,547	-0.1%	24.1%	-0.2%	27	0.0%

* Cook Inlet project produces both oil and gas; all other projects are assumed to produce only oil.

Source: ERG estimates.

TABLE 7-5

POLLUTION CONTROL OPTIONS FOR DRILLING FLUIDS AND DRILL CUTTINGS
MODEL PROJECT IMPACTS - GAS-ONLY PLATFORMS

GULF OF MEXICO

PROJECT	SCENARIO	PV of Total Production (Bbls-of-oil equivalent) Data	% Change	Corporate Cost Per BOE Data	% Change	Production Cost Per BOE Data	% Change	Net Present Value ($1000) Data	% Change	Internal Rate Of Return Data	% Change	Years Of Production Data	% Change
Gulf 1b	Baseline	1,534,266		$15.73		$11.27		($1,706)		4.7%		20	
Gulf 1b	Zero Discharge	1,534,266	0.0%	$16.08	2.3%	$11.78	4.6%	($2,249)	-31.9%	3.8%	-19.1%	20	0.0%
Gulf 1b	4-Mile Barge; 1,1 Other	1,534,266	0.0%	$15.77	0.3%	$11.34	0.6%	($1,781)	-4.4%	4.5%	-3.7%	20	0.0%
Gulf 1b	4-Mile Barge; 5,3 Other	1,534,266	0.0%	$15.76	0.2%	$11.32	0.4%	($1,763)	-3.4%	4.6%	-1.5%	20	0.0%
Gulf 1b	1,1 All	1,534,266	0.0%	$15.74	0.1%	$11.29	0.2%	($1,728)	-1.3%	4.6%	-0.8%	20	0.0%
Gulf 1b	5,3 All	1,534,266	0.0%	$15.73	0.0%	$11.27	0.0%	($1,707)	-0.1%	4.7%	-0.1%	20	0.0%
Gulf 4	Baseline	5,694,403		$13.40		$7.69		$6,885		12.8%		21	
Gulf 4	Zero Discharge	5,694,403	0.0%	$13.60	1.5%	$7.97	3.6%	$5,754	-16.4%	11.9%	-7.1%	21	0.0%
Gulf 4	4-Mile Barge; 1,1 Other	5,694,403	0.0%	$13.43	0.2%	$7.73	0.5%	$6,728	-2.3%	12.6%	-1.3%	21	0.0%
Gulf 4	4-Mile Barge; 5,3 Other	5,694,403	0.0%	$13.43	0.2%	$7.72	0.4%	$6,766	-1.7%	12.7%	-0.5%	21	0.0%
Gulf 4	1,1 All	5,694,403	0.0%	$13.41	0.1%	$7.70	0.1%	$6,839	-0.7%	12.7%	-0.3%	21	0.0%
Gulf 4	5,3 All	5,694,403	0.0%	$13.41	0.0%	$7.69	0.0%	$6,881	-0.1%	12.8%	-0.0%	21	0.0%
Gulf 6	Baseline	8,541,605		$13.12		$7.25		$12,763		14.0%		21	
Gulf 6	Zero Discharge	8,541,605	0.0%	$13.30	1.4%	$7.51	3.6%	$11,181	-12.4%	13.1%	-6.5%	21	0.0%
Gulf 6	4-Mile Barge; 1,1 Other	8,541,605	0.0%	$13.15	0.2%	$7.29	0.5%	$12,544	-1.7%	13.9%	-0.7%	21	0.0%
Gulf 6	4-Mile Barge; 5,3 Other	8,541,605	0.0%	$13.14	0.2%	$7.28	0.4%	$12,597	-1.3%	13.9%	-0.7%	21	0.0%
Gulf 6	1,1 All	8,541,605	0.0%	$13.13	0.1%	$7.26	0.1%	$12,699	-0.5%	14.0%	-0.3%	21	0.0%
Gulf 6	5,3 All	8,541,605	0.0%	$13.12	0.0%	$7.25	0.0%	$12,758	-0.0%	14.0%	-0.0%	21	0.0%
Gulf 12	Baseline	12,713,538		$13.52		$7.68		$13,767		12.1%		19	
Gulf 12	Zero Discharge	12,713,538	0.0%	$13.69	1.3%	$7.92	3.2%	$11,526	-16.3%	11.3%	-6.3%	19	0.0%
Gulf 12	4-Mile Barge; 1,1 Other	12,713,538	0.0%	$13.54	0.2%	$7.71	0.4%	$13,457	-2.3%	12.0%	-0.8%	19	0.0%
Gulf 12	4-Mile Barge; 5,3 Other	12,713,538	0.0%	$13.53	0.1%	$7.71	0.4%	$13,533	-1.7%	12.0%	-0.8%	19	0.0%
Gulf 12	1,1 All	12,713,538	0.0%	$13.52	0.1%	$7.69	0.1%	$13,677	-0.7%	12.1%	-0.3%	19	0.0%
Gulf 12	5,3 All	12,713,538	0.0%	$13.52	0.0%	$7.68	0.0%	$13,760	-0.1%	12.1%	-0.0%	19	0.0%
Gulf 24	Baseline	21,412,488		$12.29		$7.16		$49,389		16.6%		21	
Gulf 24	Zero Discharge	21,412,488	0.0%	$12.46	1.3%	$7.38	3.1%	$45,901	-7.1%	15.8%	-4.9%	21	0.0%
Gulf 24	4-Mile Barge; 1,1 Other	21,412,488	0.0%	$12.32	0.2%	$7.19	0.4%	$48,906	-1.0%	16.5%	-0.4%	21	0.0%
Gulf 24	4-Mile Barge; 5,3 Other	21,412,488	0.0%	$12.31	0.1%	$7.18	0.3%	$49,023	-0.7%	16.5%	-0.4%	21	0.0%
Gulf 24	1,1 All	21,412,488	0.0%	$12.30	0.1%	$7.17	0.1%	$49,247	-0.3%	16.5%	-0.2%	21	0.0%
Gulf 24	5,3 All	21,412,488	0.0%	$12.29	0.0%	$7.16	0.0%	$49,377	-0.0%	16.6%	-0.0%	21	0.0%

Source: ERG estimates.

TABLE 7-6

POLLUTION CONTROL OPTIONS FOR DRILLING FLUIDS AND DRILL CUTTINGS
MODEL PROJECT IMPACTS - GAS-ONLY PLATFORMS

ATLANTIC, PACIFIC, AND ALASKA

		PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost Per BOE		Production Cost Per BOE		Net Present Value ($1000)		Internal Rate Of Return		Years Of Production	
PROJECT	SCENARIO	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Atlantic	Baseline	38,935,162		$12.28		$10.52		($59,921)		4.1%		25	
Atlantic	Zero Discharge	38,935,162	0.0%	$12.46	1.5%	$10.77	2.4%	($66,969)	-11.8%	3.7%	-9.8%	25	0.0%
Atlantic	4-Mile Barge; 1,1 Other	38,935,162	0.0%	$12.30	0.2%	$10.55	0.3%	($60,728)	-1.3%	4.1%	0.0%	25	0.0%
Atlantic	4-Mile Barge; 5,3 Other	38,935,162	0.0%	$12.29	0.1%	$10.54	0.2%	($60,560)	-1.1%	4.1%	0.0%	25	0.0%
Atlantic	1,1 All	38,935,162	0.0%	$12.30	0.2%	$10.55	0.3%	($60,728)	-1.3%	4.1%	0.0%	25	0.0%
Atlantic	5,3 All	38,935,162	0.0%	$12.29	0.1%	$10.54	0.2%	($60,560)	-1.1%	4.1%	0.0%	25	0.0%
Pacific 16	Baseline	15,493,937		$10.08		$7.03		$10,241		11.8%		13	
Pacific 16	Zero Discharge	15,493,937	0.0%	$10.24	1.6%	$7.25	3.1%	$7,726	-24.6%	10.8%	-8.7%	13	0.0%
Pacific 16	4-Mile Barge; 1,1 Other	15,493,937	0.0%	$10.13	0.5%	$7.10	0.9%	$9,436	-7.9%	11.5%	-2.8%	13	0.0%
Pacific 16	4-Mile Barge; 5,3 Other	15,493,937	0.0%	$10.13	0.5%	$7.10	0.9%	$9,436	-7.9%	11.5%	-2.8%	13	0.0%
Pacific 16	1,1 All	15,493,937	0.0%	$10.08	0.0%	$7.04	0.0%	$10,202	-0.4%	11.8%	-0.1%	13	0.0%
Pacific 16	5,3 All	15,493,937	0.0%	$10.08	0.0%	$7.03	0.0%	$10,241	0.0%	11.8%	0.0%	13	0.0%
Cook Inlet	Baseline	52,694,332		$8.41		$2.96		$188,211		31.6%		29	
Cook Inlet	Zero Discharge	52,694,332	0.0%	$8.47	0.7%	$3.04	2.6%	$185,415	-1.5%	30.7%	-2.8%	29	0.0%
Cook Inlet	4-Mile Barge; 1,1 Other	52,694,332	0.0%	$8.46	0.6%	$3.02	2.1%	$186,026	-1.2%	30.9%	-2.2%	29	0.0%
Cook Inlet	4-Mile Barge; 5,3 Other	52,694,332	0.0%	$8.46	0.6%	$3.02	2.0%	$186,026	-1.2%	30.9%	-2.2%	29	0.0%
Cook Inlet	1,1 All	52,694,332	0.0%	$8.42	0.1%	$2.97	0.4%	$187,970	-0.1%	31.5%	-0.2%	29	0.0%
Cook Inlet	5,3 All	52,694,332	0.0%	$8.42	0.1%	$2.97	0.3%	$188,031	-0.1%	31.5%	-0.2%	29	0.0%

Source: ERG estimates.

2.3 percent impact is for the Zero Discharge option for the smallest project investigated -- the Gulf 1b. The 2.3 percent increase is seen for the gas-only project while the 47 cent increase is seen for the oil and gas project. Under the 4-Mile Barge; 1,1 Other option, the corporate cost per BOE increases by less than a dime for the Gulf 1b. For the Gulf 12 and larger projects, the impacts are about half as much as those seen for the Gulf 1b.

Production Cost per BOE: Slightly higher impacts are seen on the production cost than on the corporate cost. There are two reasons for this. First, the pollution control options increase investment costs. This leads to a higher amount that can be depreciated which, in turn, leads to lower taxes. The change in the corporate cost reflects after-tax effects while the change in production cost reflects pre-tax effects. Second, the baseline value for the production cost is smaller than that for the corporate cost. The smaller baseline value implies that a change of the same magnitude (e.g., two cents per BOE) will have a larger proportional impact. Under the 4-Mile Barge; 1,1 Other option, production cost increases by no more than 0.7 percent or 10 cents per BOE for the most affected project, the Gulf 1b.

Internal Rate of Return: This parameter varies greatly depending upon the size of the project and the pollution control option. For all options except Zero Discharge and all projects except the Gulf 1b, the internal rate of return (IRR) decreases by 3 percent or less. For the Zero Discharge option, except for the Gulf 1b and Atlantic 24 projects, the IRR declines by 2 to 8.2 percent. Because of the small baseline IRR values for the Gulf 1b and Atlantic 24 projects, decreases of less than 1.3 percent in the IRR itself appear as declines in the range of 10 to 20 percent. Even for the Gulf 1b the IRR declines less than 4 percent under the 4-Mile Barge; 1,1 Other option.

Net Present Value: The magnitude of the impact on net present value (NPV) is related to the size of the baseline value for NPV. For oil-producing projects (except for the Gulf 1b), the NPV declines by 7.2 percent or less for the Zero Discharge option. Gas-only projects (except for the Gulf 1b) show declines in NPV ranging from 2 to 25 percent. Because of the small net present values for the Gulf 1b projects, a decrease in the net present value of approximately half a million dollars under the Zero Discharge option appears as a decrease of 31 to 83 percent in the projects' NPV. Under the 4-Mile Barge; 1,1 Other option, the NPV for the Gulf 1b projects decline by less than 100 thousand dollars.

7.1.2 Sensitivity Analysis

Two cases were analyzed in the sensitivity analysis:

- $15/bbl price of oil
- $32/bbl price of oil

The sensitivity analysis cases were run for the Gulf 1b and the Gulf 12 oil and gas projects. The Gulf 1b is the smallest project in the study and is, therefore, likely to show greater impacts than the larger projects, while the Gulf 12 is more representative of a typical-sized Gulf project.

Tables 7-7 and 7-8 summarize results of the sensitivity analysis. There is no early shut-off of the projects, so no change is seen in the PV of total production. The corporate and production costs per BOE for each option range only within 1 percent from those in the baseline case. The net present value and the internal rate of return range more widely, but greater variation is caused by the change in oil prices than by the various regulatory options. Under the $15/bbl scenario, the Gulf 1b has a negative net present value in the baseline case. (In other words, many projects of this size would not be economical to undertake under this oil price even without the proposed regulations.) Even the Zero Discharge option for the Gulf 1b project does not lead to a negative net present value in the $21/bbl and $32/bbl scenarios.

7.2 PRODUCED WATER - BAT

The incremental costs of additional pollution controls on produced water from existing projects were applied at the mid-life of each economic model (see Section Five). There are no existing structures in the Atlantic and the only offshore project in Alaska (the Endicott field) is already required to inject its produced water by State regulations. Therefore, ERG examined the potential impacts of BAT regulations only for facilities in the Gulf of Mexico and the Pacific.

There are two sets of costs for filtration and injection. Granular filter technology costs assume that an addition to the platform is deemed necessary for the additional pollution control equipment and a 3.5 multiplier is used to account for transportation costs and other factors (see Section Six). Membrane filter technology costs assume no platform addition and a 1.5 multiplier to

TABLE 7-7

POLLUTION CONTROL OPTIONS FOR DRILLING FLUIDS AND DRILL CUTTINGS
MODEL PROJECT IMPACTS - SENSITIVITY ANALYSIS

GULF OF MEXICO - GULF 1b PROJECT - OIL AND GAS PRODUCTION

SENSITIVITY ANALYSIS	REGULATORY SCENARIO	PV of Total Production (Bbls-of-oil equivalent) Data	% Change	Corporate Cost Per BOE Data	% Change	Production Cost Per BOE Data	% Change	Net Present Value ($1000) Data	% Change	Internal Rate Of Return Data	% Change	Years Of Production Data	% Change
Baseline	Baseline	1,159,301		$21.16		$13.71		$654		9.5%		20	
	Zero Discharge	1,159,301	0.0%	$21.63	2.2%	$14.39	5.0%	$110	-83.1%	8.2%	-13.2%	20	0.0%
	4-Mile Barge; 1,1 Other	1,159,301	0.0%	$21.23	0.3%	$13.81	0.7%	$579	-11.5%	9.3%	-2.0%	20	0.0%
	4-Mile Barge; 5,3 Other	1,159,301	0.0%	$21.21	0.2%	$13.78	0.5%	$597	-8.7%	9.4%	-0.9%	20	0.0%
	1,1 All	1,159,301	0.0%	$21.18	0.1%	$13.74	0.2%	$632	-3.4%	9.4%	-0.6%	20	0.0%
	5,3 All	1,159,301	0.0%	$21.17	0.0%	$13.71	0.0%	$652	-0.3%	9.5%	-0.0%	20	0.0%
$15/bbl	Baseline	1,153,130		$17.96		$13.71		($2,806)		1.1%		18	
	Zero Discharge	1,153,130	0.0%	$18.43	2.6%	$14.39	5.0%	($3,349)	-19.4%	0.1%	-88.5%	18	0.0%
	4-Mile Barge; 1,1 Other	1,153,130	0.0%	$18.03	0.4%	$13.80	0.7%	($2,880)	-2.6%	1.0%	-9.4%	18	0.0%
	4-Mile Barge; 5,3 Other	1,153,130	0.0%	$18.01	0.3%	$13.78	0.5%	($2,861)	-2.0%	1.0%	-9.4%	18	0.0%
	1,1 All	1,153,130	0.0%	$17.98	0.1%	$13.74	0.2%	($2,828)	-0.8%	1.1%	-3.7%	18	0.0%
	5,3 All	1,153,130	0.0%	$17.96	0.0%	$13.71	0.0%	($2,808)	-0.1%	1.1%	-0.3%	18	0.0%
$32/bbl	Baseline	1,163,124		$27.06		$13.73		$7,038		22.9%		22	
	Zero Discharge	1,163,124	0.0%	$27.53	1.7%	$14.41	4.9%	$6,494	-7.7%	21.2%	-7.8%	22	0.0%
	4-Mile Barge; 1,1 Other	1,163,124	0.0%	$27.13	0.3%	$13.83	0.7%	$6,962	-1.1%	22.7%	-1.1%	22	0.0%
	4-Mile Barge; 5,3 Other	1,163,124	0.0%	$27.11	0.2%	$13.80	0.5%	$6,981	-0.8%	22.7%	-1.1%	22	0.0%
	1,1 All	1,163,124	0.0%	$27.08	0.1%	$13.76	0.2%	$7,016	-0.3%	22.9%	-0.3%	22	0.0%
	5,3 All	1,163,124	0.0%	$27.06	0.0%	$13.73	0.0%	$7,036	-0.0%	22.9%	-0.0%	22	0.0%

Source: ERG estimates.

TABLE 7-8

POLLUTION CONTROL OPTIONS FOR DRILLING FLUIDS AND DRILL CUTTINGS
MODEL PROJECT IMPACTS - SENSITIVITY ANALYSIS

GULF OF MEXICO - GULF 12 PROJECT - OIL AND GAS PRODUCTION

SENSITIVITY ANALYSIS	REGULATORY SCENARIO	PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost Per BOE		Production Cost Per BOE		Net Present Value ($1000)		Internal Rate Of Return		Years Of Production	
		Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Baseline	Baseline	9,611,069		$18.23		$8.95		$33,610		20.1%		19	
	Zero Discharge	9,611,069	0.0%	$18.46	1.3%	$9.27	3.6%	$31,369	-6.7%	18.9%	-5.9%	19	0.0%
	4-Mile Barge; 1,1 Other	9,611,069	0.0%	$18.26	0.2%	$9.00	0.5%	$33,300	-0.9%	19.9%	-1.0%	19	0.0%
	4-Mile Barge; 5,3 Other	9,611,069	0.0%	$18.25	0.1%	$8.98	0.3%	$33,375	-0.7%	20.0%	-0.5%	19	0.0%
	1,1 All	9,611,069	0.0%	$18.24	0.1%	$8.96	0.1%	$33,519	-0.3%	20.0%	-0.2%	19	0.0%
	5,3 All	9,611,069	0.0%	$18.23	0.0%	$8.95	0.0%	$33,603	-0.0%	20.1%	-0.0%	19	0.0%
$15/bbl	Baseline	9,539,096		$15.01		$8.92		$4,931		9.9%		17	
	Zero Discharge	9,539,096	0.0%	$15.24	1.6%	$9.24	3.6%	$2,690	-45.5%	9.0%	-9.2%	17	0.0%
	4-Mile Barge; 1,1 Other	9,539,096	0.0%	$15.04	0.2%	$8.96	0.5%	$4,632	-6.1%	9.8%	-1.5%	17	0.0%
	4-Mile Barge; 5,3 Other	9,539,096	0.0%	$15.03	0.1%	$8.95	0.4%	$4,707	-4.5%	9.9%	-0.5%	17	0.0%
	1,1 All	9,539,096	0.0%	$15.02	0.1%	$8.93	0.1%	$4,840	-1.8%	9.9%	-0.4%	17	0.0%
	5,3 All	9,539,096	0.0%	$15.01	0.0%	$8.92	0.0%	$4,924	-0.2%	9.9%	-0.0%	17	0.0%
$32/bbl	Baseline	9,671,105		$24.15		$9.02		$86,639		36.4%		22	
	Zero Discharge	9,671,105	0.0%	$24.39	1.0%	$9.34	3.5%	$84,397	-2.6%	34.7%	-4.6%	22	0.0%
	4-Mile Barge; 1,1 Other	9,671,105	0.0%	$24.19	0.1%	$9.06	0.5%	$86,326	-0.4%	36.1%	-0.8%	22	0.0%
	4-Mile Barge; 5,3 Other	9,671,105	0.0%	$24.18	0.1%	$9.05	0.4%	$86,401	-0.3%	36.2%	-0.5%	22	0.0%
	1,1 All	9,671,105	0.0%	$24.16	0.0%	$9.03	0.1%	$86,548	-0.1%	36.3%	-0.2%	22	0.0%
	5,3 All	9,671,105	0.0%	$24.15	0.0%	$9.02	0.0%	$86,631	-0.0%	36.4%	-0.0%	22	0.0%

Source: ERG estimates.

account for transportation, etc. Tables 7-9 through 7-15 summarize the impacts for the various options.

PV of Total Production: Increased annual operation and maintenance costs (O&M) can lead to early abandonment of a project. The offshore injection option leads to an early closure in 14 out of 26 projects with granular filter costs and for 9 out of 26 projects with membrane filter costs. Onshore injection leads to early closures in 8 out of 26 projects. Filtration leads to early closures in either 11 or 8 out of 26 projects, depending on whether granular or membrane filter costs are assumed. Most of the curtailments involve the last year of production after a substantial amount of natural decline has taken place. The impacts of early project closure are investigated in Section Nine.

Corporate Cost per BOE: The Gulf 1b assumes that one reinjection well is required to service one producing well. Under this assumption, the corporate cost per BOE may increase by a factor of 2 to 2.5 or by $12/BOE to $17/BOE (depending on whether granular or membrane filter costs are used in the evaluation). The impacts on all other projects are far less severe, with increases ranging from 2 to 51 percent or from $0.06/BOE to $5.83/BOE for the Pacific 16 gas-only project and the Gulf 4 oil and gas project, respectively. For the filtration options, the corporate cost per BOE increases by 14 to 43 percent for the Gulf 1b project. All other projects show increases of 1 to 34 percent or $0.09/BOE to $2.52/BOE.[1]

Production Cost per BOE: Production costs more than double for the Gulf 1b under the Zero Discharge option. In contrast, where four single well structures are assumed to share production/disposal facilities, production costs rise by less than 40 percent even under the higher granular filter costs. For all other structures, production cost increases do not exceed $4.45/BOE for the Zero Discharge option.

Costs for the filtration options raise production costs per BOE by 26 to 67 percent for the Gulf 1b (depending on whether membrane or granular filter

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[1] In the seventh year of operation, the Pacific 16-well gas-only project barely brings in sufficient revenue to cover operating costs. With any increment to annual operating costs, the project shuts down after 6 years of operation. Not only does the project not have to pay the additional year of operating costs, but there is surplus depreciation from the capital investments for incremental pollution control. Surplus depreciation is assumed to lower total project costs (see Appendix J). With the combination of these two factors, it appears to be slightly more economical to shut the project down after 6 years, considering the production cost per BOE.

TABLE 7-9

BAT POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - OIL AND GAS PLATFORMS

GULF OF MEXICO

Project	Scenario	Pollution Control Costs: Capital	O&M	Annualized	PV of Total Production (Bbls-of-oil equivalent): Data	% Change	Corporate Cost per BOE: Data	% Change	Production Cost per BOE: Data	% Change	Net Present Value ($1000): Data	% Change	Years of Production: Data	% Change
Gulf 1a	Baseline				315,596		$12.32		$6.14		$1,159		7	
	G-Zero Discharge	$672	$29	$144	295,947	-6.2%	$16.38	33.0%	$8.54	39.1%	$576	-50.2%	6	-14.3%
	G-Filtration	$286	$18	$61	315,596	0.0%	$14.09	14.3%	$7.34	19.6%	$890	-23.2%	7	0.0%
	Onshore	$460	$17	$89	315,596	0.0%	$15.04	22.0%	$7.88	28.4%	$766	-33.9%	7	0.0%
	M-Zero Discharge	$385	$24	$88	295,947	-6.2%	$14.63	18.7%	$7.48	21.9%	$800	-30.9%	6	-14.3%
	M-Filtration	$64	$14	$22	315,596	0.0%	$12.83	4.1%	$6.58	7.1%	$1,064	-8.2%	7	0.0%
Gulf 1b	Baseline				246,886		$11.61		$5.06		$1,083		9	
	G-Zero Discharge	$2,019	$99	$441	212,874	-13.8%	$29.17	151.3%	$15.98	216.0%	($723)	-166.8%	6	-33.3%
	G-Filtration	$579	$57	$141	227,008	-8.1%	$16.57	42.8%	$8.44	66.8%	$452	-58.2%	7	-22.2%
	Onshore	$1,710	$67	$331	227,008	-8.1%	$25.36	118.4%	$13.64	169.8%	($400)	-136.9%	7	-22.2%
	M-Zero Discharge	$1,426	$83	$299	227,008	-8.1%	$23.44	101.9%	$12.77	152.4%	($250)	-123.1%	7	-22.2%
	M-Filtration	$170	$45	$66	227,008	-8.1%	$13.28	14.4%	$6.38	26.1%	$787	-27.3%	7	-22.2%
Gulf 4	Baseline				914,626		$11.38		$4.71		$4,224		9	
	G-Zero Discharge	$2,783	$124	$518	882,192	-3.5%	$17.21	51.2%	$8.45	79.5%	$1,714	-59.4%	8	-11.1%
	G-Filtration	$1,237	$78	$250	882,192	-3.5%	$13.99	22.9%	$6.40	35.9%	$3,009	-28.8%	8	-11.1%
	Onshore	$1,846	$71	$334	882,192	-3.5%	$15.15	33.1%	$7.04	49.6%	$2,594	-38.6%	8	-11.1%
	M-Zero Discharge	$1,546	$98	$312	882,192	-3.5%	$14.68	29.0%	$6.88	46.1%	$2,710	-35.8%	8	-11.1%
	M-Filtration	$262	$59	$87	914,626	0.0%	$12.14	6.7%	$5.40	14.7%	$3,790	-10.3%	9	0.0%
Gulf 6	Baseline				1,410,228		$11.13		$4.33		$6,864		10	
	G-Zero Discharge	$3,361	$143	$587	1,371,938	-2.7%	$15.66	40.7%	$7.24	67.3%	$3,822	-44.3%	9	-10.0%
	G-Filtration	$1,792	$96	$330	1,371,938	-2.7%	$13.55	21.7%	$5.89	36.0%	$5,151	-25.0%	9	-10.0%
	Onshore	$1,890	$74	$324	1,371,938	-2.7%	$13.60	22.2%	$5.86	35.2%	$5,173	-24.6%	9	-10.0%
	M-Zero Discharge	$1,589	$106	$310	1,371,938	-2.7%	$13.32	19.7%	$5.78	33.6%	$5,258	-23.4%	9	-10.0%
	M-Filtration	$298	$67	$99	1,371,938	-2.7%	$11.58	4.1%	$4.67	7.8%	$6,353	-7.4%	9	-10.0%
Gulf 12	Baseline				2,882,620		$11.58		$5.01		$12,735		9	
	G-Zero Discharge	$3,471	$143	$636	2,780,400	-3.5%	$13.77	19.0%	$6.32	26.2%	$9,650	-24.2%	8	-11.1%
	G-Filtration	$2,812	$124	$523	2,780,400	-3.5%	$13.34	15.2%	$6.05	20.7%	$10,199	-19.9%	8	-11.1%
	Onshore	$1,970	$78	$339	2,882,620	0.0%	$12.87	11.1%	$5.86	17.0%	$10,985	-13.7%	9	0.0%
	M-Zero Discharge	$715	$90	$183	2,780,400	-3.5%	$11.99	3.6%	$5.22	4.2%	$11,849	-7.0%	8	-11.1%
	M-Filtration	$365	$80	$122	2,780,400	-3.5%	$11.76	1.6%	$5.07	1.3%	$12,142	-4.7%	8	-11.1%

Notes: There are no Gulf 40 or Gulf 58 projects within 4 miles of shore.
G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

TABLE 7-10

BAT POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - OIL AND GAS PLATFORMS

GULF OF MEXICO - continued

		Pollution Control Costs			PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Years of Production	
Project	Scenario	Capital	O&M	Annualized	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Gulf 24	Baseline				4,482,198		$10.50		$4.96		$24,605		10	
	G-Zero Discharge	$4,312	$222	$787	4,360,502	-2.7%	$12.28	16.9%	$6.05	22.1%	$20,510	-16.6%	9	-10.0%
	G-Filtration	$3,185	$194	$607	4,360,502	-2.7%	$11.81	12.4%	$5.75	16.0%	$21,443	-12.9%	9	-10.0%
	Onshore	$2,610	$80	$408	4,482,198	0.0%	$11.59	10.3%	$5.66	14.2%	$22,358	-9.1%	10	0.0%
	M-Zero Discharge	$1,079	$131	$254	4,482,198	0.0%	$11.05	5.2%	$5.39	8.8%	$23,242	-5.5%	10	0.0%
	M-Filtration	$426	$113	$154	4,482,198	0.0%	$10.78	2.6%	$5.22	5.3%	$23,795	-3.3%	10	0.0%
Gulf 40	Baseline				7,594,632		$10.14		$4.41		$44,451		11	
	G-Zero Discharge	$5,035	$292	$907	7,435,738	-2.1%	$11.37	12.1%	$5.17	17.3%	$39,444	-11.3%	10	-9.1%
	G-Filtration	$3,393	$248	$656	7,435,738	-2.1%	$10.96	8.1%	$4.91	11.4%	$40,826	-8.2%	10	-9.1%
	M-Zero Discharge	$1,471	$192	$349	7,594,632	0.0%	$10.59	4.5%	$4.78	8.5%	$42,480	-4.4%	11	0.0%
	M-Filtration	$502	$165	$206	7,594,632	0.0%	$10.36	2.1%	$4.63	5.0%	$43,312	-2.6%	11	[illegible]
Gulf 58	Baseline				11,473,877		$9.89		$4.03		$70,044		11	
	G-Zero Discharge	$6,071	$378	$1,077	11,473,877	0.0%	$10.96	10.8%	$4.79	19.0%	$63,863	-8.8%	11	0.0%
	G-Filtration	$3,647	$314	$724	11,473,877	0.0%	$10.57	6.8%	$4.54	12.7%	$65,920	-5.9%	11	0.0%
	M-Zero Discharge	$2,130	$271	$499	11,473,877	0.0%	$10.32	4.4%	$4.38	8.8%	$67,225	-4.0%	11	0.0%
	M-Filtration	$596	$227	$273	11,473,877	0.0%	$10.07	1.9%	$4.22	4.8%	$68,540	-2.1%	11	0.0%

Notes: There are no Gulf 40 or Gulf 58 projects within 4 miles of shore.
G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

TABLE 7-11

BAT POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - OIL AND GAS PLATFORMS

PACIFIC

		Pollution Control Costs			PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Years of Production	
Project	Scenario	Capital	O&M	Annualized	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Pac. 16	Baseline				3,925,097		$7.40		$3.38		$15,815		4	
	G-Zero Discharge	$7,700	$257	$1,983	3,925,097	0.0%	$11.07	49.6%	$5.56	64.4%	$9,767	-38.2%	4	0.0%
	G-Filtration	$5,255	$206	$1,377	3,925,097	0.0%	$9.92	34.0%	$4.89	44.7%	$11,621	-26.5%	4	0.0%
	Onshore	$4,248	$78	$1,045	3,925,097	0.0%	$9.31	25.7%	$4.53	34.0%	$12,224	-22.7%	4	0.0%
	M-Zero Discharge	$2,258	$164	$650	3,925,097	0.0%	$8.53	15.2%	$4.10	21.1%	$13,848	-12.4%	4	0.0%
	M-Filtration	$738	$125	$267	3,925,097	0.0%	$7.81	5.5%	$3.68	8.7%	$15,017	-5.0%	4	0.0%
Pac. 40	Baseline				9,984,146		$7.36		$2.75		$40,642		5	
	G-Zero Discharge	$10,701	$405	$2,467	9,984,146	0.0%	$9.37	27.3%	$3.98	44.9%	$31,903	-21.5%	5	0.0%
	G-Filtration	$5,979	$301	$1,438	9,984,146	0.0%	$8.50	15.5%	$3.47	26.2%	$35,564	-12.5%	5	0.0%
	M-Zero Discharge	$4,183	$299	$1,077	9,984,146	0.0%	$8.18	11.2%	$3.29	19.6%	$36,854	-9.3%	5	0.0%
	M-Filtration	$1,007	$214	$373	9,984,146	0.0%	$7.60	3.2%	$2.93	6.8%	$39,355	-3.2%	5	0.0%
Pac. 70	Baseline				21,698,858		$6.75		$2.39		$101,673		6	
	G-Zero Discharge	$16,849	$620	$3,507	21,698,858	0.0%	$8.19	21.5%	$3.30	38.0%	$87,639	-13.8%	6	0.0%
	G-Filtration	$8,322	$434	$1,837	21,698,858	0.0%	$7.48	10.9%	$2.86	19.9%	$94,353	-7.2%	6	0.0%
	Onshore	$7,991	$180	$1,569	21,698,858	0.0%	$7.33	8.7%	$2.80	17.0%	$93,191	-8.3%	6	0.0%
	M-Zero Discharge	$7,484	$500	$1,742	21,698,858	0.0%	$7.42	10.0%	$2.84	18.9%	$94,753	-6.8%	6	0.0%
	M-Filtration	$1,553	$341	$557	21,698,858	0.0%	$6.92	2.6%	$2.53	6.0%	$99,512	-2.1%	6	0.0%

Notes: G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

TABLE 7-12

BAT POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - GAS PLATFORMS

GULF OF MEXICO

		Pollution Control Costs			PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Years of Production	
Project	Scenario	Capital	O&M	Annualized	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Gulf 1a	Baseline				476,918		$8.23		$4.06		$1,194		7	
	G-Zero Discharge	$544	$21	$105	476,918	0.0%	$10.36	25.9%	$5.44	33.8%	$727	-39.1%	7	0.0%
	G-Filtration	$132	$10	$30	476,918	0.0%	$8.79	6.7%	$4.45	9.5%	$1,064	-10.9%	7	0.0%
	Onshore	$419	$12	$77	476,918	0.0%	$9.84	19.5%	$5.07	24.8%	$851	-28.8%	7	0.0%
	M-Zero Discharge	$408	$20	$83	476,918	0.0%	$9.86	19.8%	$5.14	26.4%	$830	-30.5%	7	0.0%
	M-Filtration	$37	$9	$14	476,918	0.0%	$8.43	2.4%	$4.24	4.4%	$1,136	-4.9%	7	0.0%
Gulf 1b	Baseline				370,486		$7.78		$3.37		$1,097		9	
	G-Zero Discharge	$1,672	$78	$334	340,656	-8.1%	$16.86	116.7%	$9.15	171.5%	($397)	-136.2%	7	-22.2%
	G-Filtration	$174	$34	$55	357,349	-3.5%	$8.88	14.1%	$4.25	26.2%	$839	-23.5%	8	-11.1%
	Onshore	$667	$39	$132	357,349	-3.5%	$11.31	45.4%	$5.72	69.6%	$462	-57.9%	8	-11.1%
	M-Zero Discharge	$1,494	$77	$305	340,656	-8.1%	$15.94	104.9%	$8.61	155.5%	($265)	-124.1%	7	-22.2%
	M-Filtration	$48	$34	$36	357,349	-3.5%	$8.26	6.2%	$3.89	15.4%	$933	-15.0%	8	-11.1%
Gulf 4	Baseline				1,383,149		$7.61		$3.11		$4,330		9	
	G-Zero Discharge	$2,175	$83	$393	1,334,101	-3.5%	$10.56	38.8%	$4.96	59.3%	$2,410	-44.3%	8	-11.1%
	G-Filtration	$529	$39	$106	1,383,149	0.0%	$8.38	10.2%	$3.67	17.9%	$3,786	-12.6%	9	0.0%
	Onshore	$1,675	$45	$270	1,383,149	0.0%	$9.83	29.2%	$4.53	45.5%	$2,929	-32.4%	9	0.0%
	M-Zero Discharge	$1,634	$79	$294	1,383,149	0.0%	$9.88	29.9%	$4.65	49.4%	$2,819	-34.9%	9	0.0%
	M-Filtration	$149	$36	$51	1,383,149	0.0%	$7.90	3.9%	$3.38	8.7%	$4,074	-5.9%	9	0.0%
Gulf 6	Baseline				1,980,296		$7.59		$3.08		$6,237		10	
	G-Zero Discharge	$2,231	$86	$382	1,926,528	-2.7%	$9.68	27.6%	$4.39	42.5%	$4,263	-31.7%	9	-10.0%
	G-Filtration	$563	$41	$113	1,926,528	-2.7%	$8.09	6.6%	$3.38	9.7%	$5,658	-9.3%	9	-10.0%
	Onshore	$1,699	$48	$276	1,926,528	-2.7%	$9.12	20.2%	$3.99	29.6%	$4,805	-23.0%	9	-10.0%
	M-Zero Discharge	$1,654	$80	$298	1,926,528	-2.7%	$9.15	20.6%	$4.07	32.2%	$4,706	-24.6%	9	-10.0%
	M-Filtration	$164	$37	$55	1,926,528	-2.7%	$7.73	1.8%	$3.16	2.5%	$5,965	-4.4%	9	-10.0%
Gulf 12	Baseline				4,445,835		$7.70		$3.25		$13,520		9	
	G-Zero Discharge	$1,155	$61	$212	4,445,835	0.0%	$8.20	6.6%	$3.59	10.6%	$12,431	-8.0%	9	0.0%
	G-Filtration	$632	$49	$130	4,445,835	0.0%	$7.99	3.8%	$3.46	6.5%	$12,859	-4.9%	9	0.0%
	Onshore	$1,593	$59	$270	4,445,835	0.0%	$8.37	8.7%	$3.69	13.6%	$12,123	-10.3%	9	0.0%
	M-Zero Discharge	$507	$49	$112	4,445,835	0.0%	$7.94	3.1%	$3.43	5.6%	$12,949	-4.2%	9	0.0%
	M-Filtration	$193	$41	$62	4,445,835	0.0%	$7.81	1.5%	$3.35	3.1%	$13,211	-2.3%	9	0.0%

Notes: There are no Gulf 40 or Gulf 58 projects within 4 miles of shore.
G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

TABLE 7-13

BAT POLLUTION CONTROL OPTIONS FOR PRODU
MODEL PROJECT IMPACTS - GAS PLATFORMS

GULF OF MEXICO (continued) AND PACIFIC REGIONS

		Pollution Control Costs			PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Years of Production	
Project	Scenario	Capital	O&M	Annualized	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Gulf 24	Baseline				6,854,869		$6.99		$3.24		$25,653		10	
	G-Zero Discharge	$1,423	$69	$245	6,854,869	0.0%	$7.40	5.8%	$3.52	8.5%	$24,315	-5.2%	10	0.0%
	G-Filtration	$844	$56	$158	6,854,869	0.0%	$7.24	3.6%	$3.42	5.5%	$24,795	-3.3%	10	0.0%
	Onshore	$1,660	$66	$273	6,854,869	0.0%	$7.45	6.7%	$3.55	9.5%	$24,156	-5.8%	10	0.0%
	M-Zero Discharge	$565	$53	$120	6,854,869	0.0%	$7.17	2.6%	$3.38	4.2%	$25,008	-2.5%	10	0.0%
	M-Filtration	$236	$44	$69	6,854,869	0.0%	$7.08	1.3%	$3.32	2.4%	$25,285	-1.4%	10	0.0%
Pac. 16	Baseline				8,880,736		$4.84		$2.35		$21,602		7	
	G-Zero Discharge	$2,100	$71	$432	8,490,674	-4.4%	$5.19	7.2%	$2.47	5.0%	$19,862	-8.1%	6	-14.3%
	G-Filtration	$1,319	$57	$281	8,490,674	-4.4%	$5.02	3.8%	$2.37	0.8%	$20,467	-5.3%	6	-14.3%
	M-Zero Discharge	$758	$54	$179	8,490,674	-4.4%	$4.90	1.3%	$2.30	-2.1%	$20,880	-3.3%	6	-14.3%
	M-Filtration	$375	$45	$104	8,490,674	-4.4%	$4.82	-0.3%	$2.25	-4.2%	$21,182	-1.9%	6	-14.3%

Notes: There are no gas-only Gulf 40 or Gulf 58 projects at present.
G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

TABLE 7-14

BAT POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - OIL-ONLY PLATFORMS

GULF OF MEXICO

		Pollution Control Costs			PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Years of Production	
Project	Scenario	Capital	O&M	Annualized	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Gulf 1a	Baseline				248,611		$13.64		$6.92		$970		6	
	G-Zero Discharge	$664	$29	$142	248,611	0.0%	$18.67	36.9%	$10.13	46.4%	$403	-58.4%	6	0.0%
	G-Filtration	$278	$18	$64	248,611	0.0%	$15.81	16.0%	$8.37	20.9%	$716	-26.2%	6	0.0%
	Onshore	$459	$17	$96	248,611	0.0%	$17.09	25.3%	$9.09	31.4%	$586	-39.6%	6	0.0%
	M-Zero Discharge	$384	$24	$88	248,611	0.0%	$16.63	22.0%	$8.90	28.6%	$622	-35.9%	6	0.0%
	M-Filtration	$63	$14	$23	248,611	0.0%	$14.26	4.5%	$7.44	7.4%	$882	-9.1%	6	0.0%
Gulf 1b	Baseline				200,293		$12.85		$5.73		$939		8	
	G-Zero Discharge	$2,016	$99	$440	179,049	-10.6%	$33.88	163.6%	$18.98	230.9%	($848)	-190.4%	6	-25.0%
	G-Filtration	$577	$57	$141	190,936	-4.7%	$18.92	47.2%	$10.02	74.7%	$318	-66.1%	7	-12.5%
	Onshore	$1,708	$67	$359	179,049	-10.6%	$30.32	135.9%	$16.42	186.4%	($528)	-156.2%	6	-25.0%
	M-Zero Discharge	$1,425	$83	$321	179,049	-10.6%	$27.83	116.5%	$15.25	166.0%	($372)	-139.7%	6	-25.0%
	M-Filtration	$170	$45	$65	190,936	-4.7%	$15.02	16.8%	$7.57	32.0%	$652	-30.5%	7	-12.5%
Gulf 4	Baseline				764,960		$12.78		$5.63		$3,638		9	
	G-Zero Discharge	$2,769	$123	$515	737,834	-3.5%	$19.72	54.2%	$10.08	79.0%	$1,163	-68.0%	8	-11.1%
	G-Filtration	$1,223	$77	$247	737,834	-3.5%	$15.87	24.1%	$7.62	35.4%	$2,458	-32.4%	8	-11.1%
	Onshore	$1,845	$71	$334	737,834	-3.5%	$17.29	35.2%	$8.42	49.6%	$2,030	-44.2%	8	-11.1%
	M-Zero Discharge	$1,545	$97	$312	737,834	-3.5%	$16.72	30.8%	$8.22	46.0%	$2,147	-41.0%	8	-11.1%
	M-Filtration	$261	$59	$89	737,834	-3.5%	$13.52	5.8%	$6.18	9.8%	$3,224	-11.4%	8	-11.1%
Gulf 6	Baseline				1,146,599		$12.34		$4.96		$5,960		9	
	G-Zero Discharge	$3,340	$141	$615	1,105,939	-3.5%	$17.88	44.9%	$8.48	71.1%	$2,960	-50.3%	8	-11.1%
	G-Filtration	$1,772	$95	$326	1,146,599	0.0%	$15.35	24.4%	$7.02	41.6%	$4,285	-28.1%	9	0.0%
	Onshore	$1,888	$73	$324	1,146,599	0.0%	$15.45	25.2%	$7.01	41.3%	$4,288	-28.0%	9	0.0%
	M-Zero Discharge	$1,587	$105	$310	1,146,599	0.0%	$15.11	22.4%	$6.92	39.5%	$4,376	-26.6%	9	0.0%
	M-Filtration	$297	$67	$98	1,146,599	0.0%	$13.03	5.6%	$5.58	12.5%	$5,470	-8.2%	9	0.0%
Gulf 12	Baseline				2,322,310		$12.85		$5.72		$10,903		8	
	G-Zero Discharge	$3,421	$140	$626	2,322,310	0.0%	$15.61	21.6%	$7.54	31.8%	$7,893	-27.6%	8	0.0%
	G-Filtration	$2,764	$121	$513	2,322,310	0.0%	$15.10	17.5%	$7.21	26.0%	$8,440	-22.6%	8	0.0%
	Onshore	$1,967	$78	$358	2,322,310	0.0%	$14.43	12.4%	$6.76	18.2%	$9,183	-15.8%	8	0.0%
	M-Zero Discharge	$712	$88	$181	2,322,310	0.0%	$13.52	5.2%	$6.25	9.2%	$10,051	-7.8%	8	0.0%
	M-Filtration	$362	$78	$120	2,322,310	0.0%	$13.24	3.1%	$6.07	6.1%	$10,343	-5.1%	8	0.0%

Notes: There are no Gulf 40 or Gulf 58 projects within 4 miles of shore.
G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

TABLE 7-15

BAT POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - OIL-ONLY PLATFORMS

GULF OF MEXICO - continued

Project	Scenario	Pollution Control Costs			PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Years of Production	
		Capital	O&M	Annualized	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Gulf 24	Baseline				3,644,365		$11.68		$5.68		$21,365		9	
	G-Zero Discharge	$4,302	$220	$783	3,644,365	0.0%	$13.96	19.6%	$7.23	27.4%	$17,341	-18.8%	9	0.0%
	G-Filtration	$3,181	$192	$604	3,644,365	0.0%	$13.40	14.8%	$6.88	21.2%	$18,268	-14.5%	9	0.0%
	Onshore	$2,596	$80	$427	3,644,365	0.0%	$13.00	11.3%	$6.52	15.0%	$19,155	-10.3%	9	0.0%
	M-Zero Discharge	$1,076	$129	$260	3,644,365	0.0%	$12.33	5.6%	$6.19	9.1%	$20,052	-6.1%	9	0.0%
	M-Filtration	$425	$111	$155	3,644,365	0.0%	$12.00	2.8%	$5.98	5.4%	$20,599	-3.6%	9	0.0%
Gulf 40	Baseline				6,212,018		$11.27		$5.06		$38,926		10	
	G-Zero Discharge	$5,026	$292	$906	6,212,018	0.0%	$12.88	14.2%	$6.19	22.2%	$33,990	-12.7%	10	0.0%
	G-Filtration	$3,389	$248	$656	6,212,018	0.0%	$12.39	9.9%	$5.88	16.1%	$35,369	-9.1%	10	0.0%
	M-Zero Discharge	$1,468	$192	$358	6,212,018	0.0%	$11.82	4.8%	$5.51	8.8%	$37,012	-4.9%	10	0.0%
	M-Filtration	$500	$165	$208	6,212,018	0.0%	$11.53	2.3%	$5.32	5.1%	$37,834	-2.8%	10	0.0%
Gulf 58	Baseline				9,582,253		$11.11		$4.82		$61,581		11	
	G-Zero Discharge	$5,819	$365	$1,073	9,381,774	-2.1%	$12.23	10.0%	$5.51	14.3%	$55,650	-9.6%	10	-9.1%
	G-Filtration	$3,642	$309	$719	9,582,253	0.0%	$11.92	7.3%	$5.43	12.7%	$57,483	-6.7%	11	0.0%
	M-Zero Discharge	$1,886	$259	$459	9,582,253	0.0%	$11.58	4.2%	$5.21	8.1%	$58,994	-4.2%	11	0.0%
	M-Filtration	$594	$223	$268	9,582,253	0.0%	$11.33	1.9%	$5.05	4.7%	$60,100	-2.4%	11	0.0%

Notes: There are no Gulf 40 or Gulf 58 projects within 4 miles of shore.
G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

costs are used in the evaluation). For all other structures, cost increases are less than $2/BOE.

Net Present Value: For the Gulf 1b oil and gas project, the NPV changes from positive to negative for the Zero Discharge options while it remains positive for the filtration options. All other projects show no change in the sign of the baseline net present value (i.e., all that begin positive remain positive and all that begin negative remain negative). Decreases of 2 to 59 percent are seen for the Zero Discharge option with the higher increases associated with projects having small baseline net present values. Section Nine examines the potential loss of production from all structures, including the Gulf 1b.

7.3 PRODUCED WATER - NSPS

The incremental costs of additional pollution controls on produced water from future projects are applied at the beginning of each economic model (see Section Five). Future projects are projected for all four regions -- Gulf of Mexico, Pacific, Atlantic, and Alaska. Section Four discusses the methodology used to estimate the number of projects that go into operation during 1986 - 2000.

As described in Section 7.2 for BAT produced water, there are two sets of costs for filtration and injection. They are differentiated by whether or not an addition to the platform is deemed necessary for the additional pollution control equipment and by the multiplier used to account for transportation costs and other factors (see Section Six). The impacts for the various options are summarized in Tables 7-16 through 7-21.

7.3.1 Financial Summary Statistics

PV of Total Production: Increased annual operation and maintenance costs (O&M) can lead to early abandonment of a project. Only 5 out of 24 projects show early closures, and these closures occur regardless of the disposal option. This implies that the project brings in just enough revenue in the last year of operation to cover operating costs, i.e., any additional annual costs will cause the project to close a year earlier. The impacts of early project closure are investigated in Section Nine.

TABLE 7-..

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - OIL AND GAS PLATFORMS

GULF OF MEXICO

		Pollution Control Costs			PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Internal Rate of Return		Years of Production	
Project	Scenario	Capital	O&M	Annualized	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Gulf 1b	Baseline				1,159,301		$21.16		$13.71		$654		9.5%		20	
	G-Zero Discharge	$1,928	$97	$278	1,148,742	-0.9%	$24.58	16.2%	$16.17	17.9%	($1,346)	-305.8%	5.1%	-45.8%	17	-15.0%
	Onshore	$1,711	$85	$245	1,148,742	-0.9%	$24.19	14.3%	$15.88	15.8%	($1,114)	-270.4%	5.6%	-40.8%	17	-15.0%
	G-Filtration	$485	$55	$96	1,153,130	-0.5%	$22.19	4.8%	$14.57	6.3%	($41)	-106.3%	7.9%	-16.8%	18	-10.0%
	M-Zero Discharge	$1,462	$84	$220	1,148,742	-0.9%	$23.81	12.5%	$15.66	14.2%	($931)	-242.3%	6.0%	-37.0%	17	-15.0%
	M-Filtration	$205	$47	$62	1,153,130	-0.5%	$21.72	2.7%	$14.27	4.1%	$210	-67.8%	8.5%	-10.7%	18	-10.0%
Gulf 4	Baseline				4,301,632		$18.09		$8.98		$15,649		21.4%		21	
	G-Zero Discharge	$2,227	$118	$313	4,293,709	-0.2%	$19.08	5.5%	$9.70	8.0%	$13,439	-14.1%	19.0%	-11.1%	20	-4.8%
	Onshore	$1,848	$94	$256	4,293,709	-0.2%	$18.90	4.5%	$9.56	6.5%	$13,836	-11.6%	19.4%	-9.3%	20	-4.8%
	G-Filtration	$707	$72	$130	4,293,709	-0.2%	$18.45	2.0%	$9.27	3.2%	$14,743	-5.8%	20.5%	-4.3%	20	-4.8%
	M-Zero Discharge	$1,571	$99	$235	4,293,709	-0.2%	$18.81	4.0%	$9.52	6.0%	$13,993	-10.6%	19.6%	-8.3%	20	-4.8%
	M-Filtration	$299	$61	$83	4,293,709	-0.2%	$18.28	1.1%	$9.16	2.0%	$15,083	-3.6%	20.9%	-2.5%	20	-4.8%
Gulf 6	Baseline				6,452,448		$17.71		$8.40		$25,909		23.1%		21	
	G-Zero Discharge	$2,339	$128	$328	6,452,448	0.0%	$18.41	4.0%	$8.92	6.2%	$23,547	-9.1%	21.4%	-7.6%	21	0.0%
	Onshore	$1,892	$94	$257	6,452,448	0.0%	$18.27	3.2%	$8.80	4.8%	$24,053	-7.2%	21.7%	-6.0%	21	0.0%
	G-Filtration	$805	$81	$147	6,452,448	0.0%	$17.99	1.6%	$8.63	2.7%	$24,867	-4.0%	22.4%	-3.0%	21	0.0%
	M-Zero Discharge	$1,615	$108	$245	6,452,448	0.0%	$18.22	2.9%	$8.78	4.6%	$24,157	-6.8%	21.8%	-5.4%	21	0.0%
	M-Filtration	$341	$69	$94	6,452,448	0.0%	$17.86	0.9%	$8.55	1.7%	$25,254	-2.5%	22.7%	-1.5%	21	0.0%
Gulf 12	Baseline				9,611,069		$18.23		$8.95		$33,610		20.1%		19	
	G-Zero Discharge	$1,598	$115	$242	9,611,069	0.0%	$18.56	1.8%	$9.20	2.8%	$31,883	-5.1%	19.3%	-3.8%	19	0.0%
	Onshore	$1,976	$94	$260	9,611,069	0.0%	$18.61	2.1%	$9.22	3.0%	$31,735	-5.6%	19.2%	-4.3%	19	0.0%
	G-Filtration	$990	$97	$171	9,611,069	0.0%	$18.45	1.2%	$9.13	2.0%	$32,401	-3.6%	19.6%	-2.5%	19	0.0%
	M-Zero Discharge	$746	$93	$145	9,611,069	0.0%	$18.41	1.0%	$9.10	1.7%	$32,590	-3.0%	19.7%	-2.1%	19	0.0%
	M-Filtration	$419	$83	$107	9,611,069	0.0%	$18.35	0.6%	$9.06	1.3%	$32,870	-2.2%	19.8%	-1.4%	19	0.0%
Gulf 24	Baseline				17,470,722		$16.26		$8.13		$95,532		27.3%		21	
	G-Zero Discharge	$2,225	$163	$334	17,470,722	0.0%	$16.52	1.6%	$8.33	2.5%	$93,073	-2.6%	26.6%	-2.5%	21	0.0%
	Onshore	$2,632	$103	$320	17,470,722	0.0%	$16.53	1.7%	$8.32	2.4%	$93,137	-2.5%	26.6%	-2.7%	21	0.0%
	G-Filtration	$1,131	$136	$213	17,470,722	0.0%	$16.41	0.9%	$8.26	1.6%	$93,983	-1.6%	26.9%	-1.4%	21	0.0%
	M-Zero Discharge	$1,112	$136	$212	17,470,722	0.0%	$16.40	0.9%	$8.26	1.6%	$93,996	-1.6%	26.9%	-1.4%	21	0.0%
	M-Filtration	$474	$118	$140	17,470,722	0.0%	$16.34	0.5%	$8.22	1.1%	$94,536	-1.0%	27.1%	-0.8%	21	0.0%

Notes: G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

TABLE 7-17

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - OIL AND GAS PLATFORMS

GULF OF MEXICO - continued

Project	Scenario	Pollution Control Costs			PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Internal Rate of Return		Years of Production	
		Capital	O&M	Annualized	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Gulf 40	Baseline				29,889,385		$16.04		$7.74		$169,856		25.2%		23	
	G-Zero Discharge	$2,935	$235	$450	29,889,385	0.0%	$16.25	1.3%	$7.91	2.1%	$166,454	-2.0%	24.8%	-1.7%	23	0.0%
	Onshore	$3,176	$125	$380	29,889,385	0.0%	$16.24	1.2%	$7.88	1.8%	$166,931	-1.7%	24.8%	-1.7%	23	0.0%
	G-Filtration	$1,335	$192	$276	29,889,385	0.0%	$16.15	0.7%	$7.84	1.3%	$167,807	-1.2%	25.0%	-0.8%	23	0.0%
	M-Zero Discharge	$1,510	$199	$297	29,889,385	0.0%	$16.16	0.8%	$7.85	1.4%	$167,649	-1.3%	25.0%	-0.9%	23	0.0%
	M-Filtration	$560	$171	$191	29,889,385	0.0%	$16.11	0.4%	$7.81	0.9%	$168,464	-0.8%	25.1%	-0.4%	23	0.0%
Gulf 58	Baseline				35,194,925		$16.53		$7.90		$182,742		20.7%		25	
	G-Zero Discharge	$3,960	$324	$606	35,194,925	0.0%	$16.72	1.2%	$8.05	1.9%	$178,986	-2.1%	20.4%	-1.4%	25	0.0%
	G-Filtration	$1,587	$260	$352	35,194,925	0.0%	$16.72	1.2%	$7.99	1.1%	$180,610	-1.2%	20.6%	-0.6%	25	0.0%
	M-Zero Discharge	$2,177	$280	$419	35,194,925	0.0%	$16.65	0.7%	$8.01	1.3%	$180,187	-1.4%	20.5%	-0.8%	25	0.0%
	M-Filtration	$666	$237	$255	35,194,925	0.0%	$16.59	0.4%	$7.96	0.8%	$181,235	-0.8%	20.6%	-0.3%	25	0.0%

Notes: No 58-well structures are projected within 4 miles of shore in the Gulf of Mexico.
G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

TABLE 7-18

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - OIL AND GAS PLATFORMS

ATLANTIC AND PACIFIC

		Pollution Control Costs			PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Internal Rate of Return		Years of Production	
Project	Scenario	Capital	O&M	Annualized	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Atl. 24	Baseline				25,801,198		$19.05		$16.52		($66,121)		2.6%		21	
	G-Zero Discharge	$6,297	$316	$824	25,801,198	0.0%	$19.39	1.8%	$16.76	1.5%	($70,702)	-6.9%	2.2%	-14.2%	21	0.0%
	G-Filtration	$2,303	$221	$388	25,801,198	0.0%	$19.19	0.8%	$16.63	0.7%	($68,234)	-3.2%	2.4%	-7.5%	21	0.0%
	M-Zero Discharge	$3,780	$277	$567	25,801,198	-0.0%	$19.27	1.2%	$16.68	1.0%	($69,234)	-4.7%	2.3%	-10.3%	21	0.0%
	M-Filtration	$966	$199	$251	25,801,198	-0.0%	$19.13	0.4%	$16.59	0.4%	($67,450)	-2.0%	2.5%	-5.4%	21	0.0%
Pac. 16	Baseline				11,449,953		$12.96		$7.19		$45,337		39.4%		9	
	G-Zero Discharge	$4,365	$203	$718	11,449,953	0.0%	$13.55	4.5%	$7.58	5.4%	$42,113	-7.1%	35.9%	-8.9%	9	0.0%
	G-Filtration	$1,973	$152	$370	11,449,953	0.0%	$13.24	2.2%	$7.39	2.8%	$43,698	-3.6%	37.7%	-4.4%	9	0.0%
	M-Zero Discharge	$2,320	$172	$430	11,449,953	0.0%	$13.29	2.5%	$7.42	3.2%	$43,427	-4.2%	37.4%	-5.1%	9	0.0%
	M-Filtration	$826	$133	$207	11,449,953	0.0%	$13.10	1.1%	$7.30	1.6%	$44,440	-2.0%	38.5%	-2.2%	9	0.0%
Pac. 40	Baseline				20,252,704		$12.89		$6.05		$81,686		33.8%		10	
	G-Zero Discharge	$7,376	$359	$1,181	20,252,704	0.0%	$13.34	3.5%	$6.35	4.9%	$77,199	-5.5%	31.6%	-6.4%	10	0.0%
	G-Filtration	$2,707	$255	$527	20,252,704	0.0%	$13.07	1.4%	$6.18	2.2%	$79,721	-2.4%	32.9%	-2.5%	10	0.0%
	M-Zero Discharge	$4,283	$317	$768	20,252,704	0.0%	$13.16	2.1%	$6.24	3.2%	$78,802	-3.5%	32.5%	-3.9%	10	0.0%
	M-Filtration	$1,137	$232	$316	20,252,704	0.0%	$12.98	0.7%	$6.13	1.3%	$80,539	-1.4%	33.4%	-1.2%	10	0.0%
Pac. 70	Baseline				29,277,100		$12.38		$5.94		$132,919		29.5%		12	
	G-Zero Discharge	$12,668	$585	$1,881	29,277,100	0.0%	$12.85	3.8%	$6.24	5.1%	$126,176	-5.1%	27.8%	-5.8%	12	0.0%
	G-Filtration	$3,782	$398	$736	29,277,100	0.0%	$12.54	1.3%	$6.06	2.0%	$130,351	-1.9%	28.9%	-2.0%	12	0.0%
	M-Zero Discharge	$7,658	$527	$1,273	29,277,100	-0.0%	$12.68	2.4%	$6.14	3.4%	$128,410	-3.4%	28.4%	-3.7%	12	0.0%
	M-Filtration	$1,592	$368	$468	29,277,100	-0.0%	$12.47	0.7%	$6.01	1.2%	$131,338	-1.2%	29.2%	-1.0%	12	0.0%

Notes: G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

TABLE 7-19

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - OIL AND GAS PLATFORMS AND OIL-ONLY PLATFORMS

ALASKA

PROJECT	SCENARIO	Pollution Control Costs Capital	O&M	Annualized	PV of Total Production (Bbls-of-oil equivalent) Data	% Change	Corporate Cost Per BOE Data	% Change	Production Cost Per BOE Data	% Change	Net Present Value ($1000) Data	% Change	Internal Rate Of Return Data	% Change	Years (Production Data	% Change
Cook Inlet	Baseline				61,707,003		$13.22		$4.18		$357,708		39.0%		30	
	G-Zero Discharge	$13,462	$596	$1,593	61,707,003	0.0%	$13.55	2.5%	$4.42	5.7%	$347,200	-2.9%	37.0%	-5.1%	30	0.0
	G-Filtration	$3,907	$369	$628	61,707,003	0.0%	$13.33	0.8%	$4.28	2.3%	$353,666	-1.1%	38.4%	-1.6%	30	0.0
	M-Zero Discharge	$8,848	$541	$1,173	61,707,003	0.0%	$13.44	1.7%	$4.36	4.2%	$350,045	-2.1%	37.7%	-3.5%	30	0.0
	M-Filtration	$1,643	$341	$421	61,707,003	0.0%	$13.28	0.4%	$4.25	1.6%	$355,069	-0.7%	38.7%	-0.8%	30	0.0
Beaufort: gravel-island	Baseline				73,172,498		$12.19		$5.53		$191,157		18.4%		30	
	G-Zero Discharge	$36,655	$655	$3,347	73,172,498	0.0%	$12.68	4.0%	$5.84	5.5%	$174,043	-9.0%	17.1%	-7.0%	30	0.0
	G-Filtration	$10,497	$653	$1,320	73,172,498	0.0%	$12.35	1.3%	$5.65	2.2%	$184,655	-3.4%	18.0%	-2.3%	30	0.0
	M-Zero Discharge	$20,948	$623	$2,106	73,172,498	-0.0%	$12.48	2.4%	$5.72	3.5%	$180,520	-5.6%	17.6%	-4.2%	30	0.0
	M-Filtration	$4,426	$610	$816	73,172,498	-0.0%	$12.27	0.7%	$5.60	1.3%	$187,263	-2.0%	18.2%	-1.1%	30	0.0
Beaufort: platform	Baseline				67,592,103		$11.50		$6.33		$233,074		20.5%		28	
	G-Zero Discharge	$36,300	$646	$3,351	67,592,103	0.0%	$11.99	4.3%	$6.64	4.8%	$207,373	-11.0%	19.2%	-6.4%	28	0.0
	G-Filtration	$10,389	$630	$1,303	67,592,103	0.0%	$11.66	1.4%	$6.45	1.9%	$217,189	-6.8%	20.1%	-2.1%	28	0.0
	M-Zero Discharge	$20,823	$615	$2,111	67,592,103	-0.0%	$11.79	2.5%	$6.52	3.1%	$213,302	-8.5%	19.7%	-3.9%	28	0.0
	M-Filtration	$4,380	$588	$799	67,592,103	-0.0%	$11.58	0.7%	$6.40	1.2%	$219,583	-5.8%	20.3%	-1.1%	28	0.0
Navarin	Baseline				73,172,498		$12.41		$7.47		$175,208		15.2%		30	
	G-Zero Discharge	$36,656	$655	$3,347	73,172,498	0.0%	$12.90	3.9%	$7.77	4.1%	$158,093	-9.8%	14.3%	-6.2%	30	0.0
	G-Filtration	$10,497	$653	$1,320	73,172,498	0.0%	$12.57	1.3%	$7.59	1.6%	$168,706	-3.7%	14.8%	-2.3%	30	0.0
	M-Zero Discharge	$20,948	$623	$2,106	73,172,498	-0.0%	$12.70	2.3%	$7.66	2.5%	$164,571	-6.1%	14.6%	-3.9%	30	0.0
	M-Filtration	$4,426	$610	$816	73,172,498	-0.0%	$12.49	0.6%	$7.54	1.0%	$171,315	-2.2%	15.0%	-1.4%	30	0.0
Norton	Baseline				61,740,561		$11.22		$6.09		$220,856		24.1%		27	
	G-Zero Discharge	$22,514	$681	$2,322	61,635,409	-0.2%	$11.65	3.9%	$6.36	4.5%	$207,676	-6.0%	22.6%	-6.2%	26	-3.7
	G-Filtration	$8,193	$460	$1,008	61,635,409	-0.2%	$11.39	1.5%	$6.20	1.8%	$215,239	-2.5%	23.5%	-2.5%	26	-3.7
	M-Zero Discharge	$11,725	$617	$1,411	61,635,409	-0.2%	$11.46	2.1%	$6.25	2.6%	$212,979	-3.6%	23.3%	-3.5%	26	-3.7
	M-Filtration	$3,449	$428	$605	61,635,409	-0.2%	$11.30	0.7%	$6.15	1.0%	$217,585	-1.5%	23.8%	-1.2%	26	-3.7

Notes: Cook Inlet project produces both oil and gas; all other projects are assumed to produce only oil.
G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

TABLE 7-20

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - GAS-ONLY PLATFORMS

GULF OF MEXICO

		Pollution Control Costs			PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Internal Rate of Return		Years of Production	
Project	Scenario	Capital	O&M	Annualized	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Gulf 1b	Baseline				1,534,266		$15.73		$11.27		($1,706)		4.7%		20	
	G-Zero Discharge	$1,644	$77	$228	1,524,970	-0.6%	$17.91	13.9%	$12.83	13.9%	($3,382)	-98.3%	1.7%	-63.8%	18	-10.0%
	Onshore	$667	$41	$100	1,530,172	-0.3%	$16.65	5.8%	$11.96	6.2%	($2,447)	-43.4%	3.3%	-29.9%	19	-5.0%
	G-Filtration	$146	$34	$45	1,530,172	-0.3%	$16.03	1.9%	$11.58	2.8%	($2,028)	-18.9%	4.0%	-14.9%	19	-5.0%
	M-Zero Discharge	$1,508	$77	$215	1,524,970	-0.6%	$17.75	12.9%	$12.74	13.0%	($3,279)	-92.2%	1.9%	-60.6%	18	-10.0%
	M-Filtration	$62	$34	$36	1,530,172	-0.3%	$15.94	1.3%	$11.52	2.3%	($1,964)	-15.1%	4.1%	-12.6%	19	-5.0%
Gulf 4	Baseline				5,694,403		$13.40		$7.69		$6,885		12.8%		21	
	G-Zero Discharge	$2,089	$82	$268	5,682,468	-0.2%	$14.08	5.1%	$8.16	6.1%	$4,980	-27.7%	11.3%	-11.4%	20	-4.8%
	Onshore	$1,675	$49	$199	5,682,468	-0.2%	$13.93	3.9%	$8.04	4.5%	$5,461	-20.7%	11.7%	-8.8%	20	-4.8%
	G-Filtration	$443	$38	$75	5,682,468	-0.2%	$13.57	1.2%	$7.82	1.7%	$6,360	-7.6%	12.4%	-3.3%	20	-4.8%
	M-Zero Discharge	$1,672	$79	$226	5,682,468	-0.2%	$13.96	4.2%	$8.08	5.1%	$5,280	-23.3%	11.6%	-9.6%	20	-4.8%
	M-Filtration	$188	$36	$50	5,682,468	-0.2%	$13.49	0.7%	$7.77	1.1%	$6,543	-5.0%	12.5%	-2.1%	20	-4.8%
Gulf 6	Baseline				8,541,605		$13.12		$7.25		$12,763		14.0%		21	
	G-Zero Discharge	$2,139	$85	$272	8,541,605	0.0%	$13.58	3.5%	$7.58	4.5%	$10,795	-15.4%	13.0%	-7.4%	21	0.0%
	Onshore	$1,699	$54	$204	8,541,605	0.0%	$13.48	2.7%	$7.49	3.4%	$11,282	-11.6%	13.2%	-5.7%	21	0.0%
	G-Filtration	$471	$40	$79	8,541,605	0.0%	$13.24	0.9%	$7.35	1.3%	$12,199	-4.4%	13.7%	-2.0%	21	0.0%
	M-Zero Discharge	$1,690	$81	$227	8,541,605	0.0%	$13.49	2.9%	$7.52	3.8%	$11,126	-12.8%	13.1%	-6.1%	21	0.0%
	M-Filtration	$199	$37	$52	8,541,605	0.0%	$13.18	0.5%	$7.31	0.9%	$12,400	-2.8%	13.8%	-1.2%	21	0.0%
Gulf 12	Baseline				12,713,538		$13.52		$7.68		$13,767		12.1%		19	
	G-Zero Discharge	$1,051	$57	$144	12,713,538	0.0%	$13.67	1.1%	$7.79	1.5%	$12,731	-7.5%	11.8%	-2.8%	19	0.0%
	Onshore	$1,748	$68	$217	12,713,538	0.0%	$13.77	1.8%	$7.85	2.2%	$12,193	-11.4%	11.6%	-4.2%	19	0.0%
	G-Filtration	$527	$46	$86	12,713,538	0.0%	$13.60	0.6%	$7.75	0.9%	$13,155	-4.4%	11.9%	-1.6%	19	0.0%
	M-Zero Discharge	$537	$49	$90	12,713,538	0.0%	$13.61	0.6%	$7.75	0.9%	$13,130	-4.6%	11.9%	-1.6%	19	0.0%
	M-Filtration	$223	$41	$54	12,713,538	0.0%	$13.56	0.3%	$7.72	0.6%	$13,391	-2.7%	12.0%	-0.9%	19	0.0%
Gulf 24	Baseline				21,412,488		$12.29		$7.16		$49,389		16.6%		21	
	G-Zero Discharge	$1,195	$66	$151	21,412,488	0.0%	$12.40	0.9%	$7.23	1.0%	$48,238	-2.3%	16.3%	-1.6%	21	0.0%
	Onshore	$1,815	$83	$217	21,412,488	0.0%	$12.45	1.3%	$7.26	1.5%	$47,733	-3.4%	16.2%	-2.3%	21	0.0%
	G-Filtration	$635	$53	$94	21,412,488	0.0%	$12.35	0.5%	$7.20	0.6%	$48,685	-1.4%	16.4%	-1.0%	21	0.0%
	M-Zero Discharge	$588	$54	$91	21,412,488	0.0%	$12.35	0.5%	$7.20	0.6%	$48,710	-1.4%	16.4%	-1.0%	21	0.0%
	M-Filtration	$269	$45	$57	21,412,488	0.0%	$12.32	0.3%	$7.19	0.4%	$48,970	-0.8%	16.5%	-0.6%	21	0.0%

Notes: G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

TABLE 7-21

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - GAS-ONLY PLATFORMS

PACIFIC, ATLANTIC, AND ALASKA REGIONS

		Pollution Control Costs			PV of Total Production (Bbls-of-oil equivalent)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Internal Rate of Return		Years of Production	
Project	Scenario	Capital	O&M	Annualized	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change	Data	% Change
Pac. 16	Baseline				15,493,937		$10.08		$7.03		$10,241		11.8%		13	
	G-Zero Discharge	$1,762	$67	$244	15,493,937	0.0%	$10.24	1.6%	$7.14	1.6%	$9,021	-11.9%	11.3%	-3.9%	13	0.0%
	G-Filtration	$1,011	$54	$152	15,493,937	0.0%	$10.17	0.9%	$7.10	1.0%	$9,488	-7.4%	11.5%	-2.3%	13	0.0%
	M-Zero Discharge	$795	$55	$129	15,493,937	0.0%	$10.15	0.7%	$7.09	0.9%	$9,604	-6.2%	11.6%	-1.9%	13	0.0%
	M-Filtration	$428	$46	$83	15,493,937	0.0%	$10.12	0.4%	$7.07	0.6%	$9,840	-3.9%	11.7%	-1.1%	13	0.0%
Atlan.	Baseline				38,935,162		$12.28		$10.52		($59,921)		4.1%		25	
	G-Zero Discharge	$2,013	$74	$52	38,935,162	0.0%	$12.28	0.0%	$10.53	0.1%	($60,203)	-0.5%	4.1%	-0.2%	25	0.0%
	G-Filtration	$1,232	$59	$41	38,935,162	0.0%	$12.28	0.0%	$10.53	0.1%	($60,145)	-0.4%	4.1%	-0.1%	25	0.0%
	M-Zero Discharge	$893	$59	$42	38,935,162	0.0%	$12.28	0.0%	$10.53	0.1%	($60,147)	-0.4%	4.1%	-0.1%	25	0.0%
	M-Filtration	$521	$50	$35	38,935,162	0.0%	$12.28	0.0%	$10.53	0.1%	($60,112)	-0.3%	4.1%	-0.1%	25	0.0%
Cook	Baseline				52,694,332		$8.41		$2.96		$188,211		31.6%		29	
	G-Zero Discharge	$2,456	$54	$246	52,694,332	0.0%	$8.48	0.8%	$3.01	1.5%	$186,572	-0.9%	31.1%	-1.5%	29	[illegible]
	G-Filtration	$1,540	$44	$162	52,694,332	0.0%	$8.46	0.6%	$2.99	1.1%	$187,135	-0.6%	31.3%	-0.9%	29	[illegible]
	M-Zero Discharge	$1,056	$48	$126	52,694,332	0.0%	$8.44	0.4%	$2.99	0.8%	$187,385	-0.4%	31.4%	-0.7%	29	0.0%
	M-Filtration	$652	$39	$86	52,694,332	0.0%	$8.43	0.3%	$2.98	0.6%	$187,650	-0.3%	31.5%	-0.4%	29	0.0%

Notes: G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
Source: ERG estimates.

Corporate Cost per BOE: The Gulf 1b assumes that one reinjection well is required to service one producing well. Under this assumption, the corporate cost per BOE may increase by 13 to 16 percent or about \$2.00/BOE to \$3.50/BOE (depending on whether granular or membrane filter costs are used in the evaluation). This increase is enough, however, to change the net present value from positive to negative (see below). The impacts on all other projects are far less severe, with increases ranging from 1 to 6 percent or from \$0.07/BOE to \$1.01/BOE for the Cook Inlet gas-only project to the Gulf 4 oil and gas project.

For the filtration option, the corporate cost per BOE increases by 2 to 5 percent for the Gulf 1b project. All other projects show increases of 0.3 to 2.2 percent.

Production Cost per BOE: Production costs increase by 14 to 18 percent for the Gulf 1b under the Zero Discharge option. For all other structures, production cost increases do not exceed 8 percent or \$0.72/BOE for the Zero Discharge option.

Costs for the filtration options raise production costs per BOE by 4 to 6 percent for the Gulf 1b (depending on whether membrane granular filter costs are used in the evaluation). For all other structures, cost increases do not exceed 3.5 percent or less than 30 cents per BOE.

Net Present Value: For the Gulf 1b oil and gas project, the NPV changes from positive to negative for the Zero Discharge options, while it remains positive for the filtration option using membrane filter costs. All other projects show no change in the sign of the baseline net present value (i.e., all that begin positive remain positive and all that begin negative remain negative). Decreases of 2 to 28 percent are seen for the Zero Discharge option, with the greater change occurring in projects with small baseline net present values. Section Nine examines the potential loss of production from all structures, including the Gulf 1b.

7.3.2 Sensitivity Analysis

Two sensitivity cases were examined for for re-injection and filtration:

- $15/bbl
- $32/bbl

The cases were run for the Gulf 1b and Gulf 12 oil and gas projects (see Tables 7-22 and 7-23). Granular filter costs were used because they are higher than membrane filter costs. The change in the price of oil has a greater impact on the financial summary statistics than do the regulatory options within a given price scenario.

7.4 COMBINED EFFECTS OF SELECTED REGULATORY OPTIONS

Existing projects, for the most part, will have had their drilling programs completed by the time any new effluent standards are enacted. The rare exceptions will be drilling programs on large platforms that were set before the regulations go into place but will not be completed until after the regulations are in effect. Existing projects, then, primarily bear BAT produced water costs. Section 7.2 describes the impacts from these costs on representative facilities.

New projects will bear the combined costs of increased pollution control for both drilling and production wastes. In this section, ERG examines the impacts of the costs for the combinations discussed in Section 6.4 on the Gulf 1b and Gulf 12 oil and gas projects.

The results are shown in Table 7-24. The first line is the baseline case without any added regulatory costs of increased pollution control. The following lines list the financial summary statistics when the respective combination of NSPS drilling fluids, drill cuttings, and produced water pollution control options are considered. These data are given for five regulatory combinations for both the Gulf 1b and Gulf 12 projects. The combined impacts were calculated by running the models with both the drilling fluids and drill cutting control costs and the produced water control costs. Combining the pollution control costs shows that the effects are only additive (i.e., the combined effects are roughly equal to the sum of the two effects when analyzed independently).

TABLE 7-22

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - SENSITIVITY ANALYSIS
GRANULAR FILTER COSTS

GULF OF MEXICO - GULF 1B PROJECT - OIL AND GAS PRODUCTION

Sensitivity Analysis	Regulatory Scenario	Pollution Control Costs Capital	O&M	Annualized	PV of Total Production (BOE) Data	Change	Corporate Cost per BOE Data	Change	Production Cost per BOE Data	Change	Net Present Value ($1000) Data	Change	Internal Rate of Return Data	Change	Years of Production Data	Change
Baseline	Baseline				1,159,301		$21.16		$13.71		$654		9.5%		20	
	Zero Discharge	$1,928	$97	$278	1,148,742	-0.9%	$24.58	16.2%	$16.17	17.9%	($1,346)	-305.8%	5.1%	-45.8%	17	-15.0%
	Onshore Shallow	$1,711	$85	$245	1,148,742	-0.9%	$24.19	14.3%	$15.88	15.8%	($1,114)	-270.4%	5.6%	-40.8%	17	-15.0%
	Filtration	$485	$55	$96	1,153,130	-0.5%	$22.19	4.8%	$14.57	6.3%	($41)	-106.3%	7.9%	-16.8%	18	-10.0%
$15/bbl	Baseline				1,153,130		$17.96		$13.71		($2,804)		1.1%		18	
	Zero Discharge	$1,928	$97	$289	1,136,083	-1.5%	$21.42	19.3%	$16.20	18.2%	($4,770)	-270.1%	-3.2%	-385.0%	15	-16.7%
	Onshore Shallow	$1,711	$85	$255	1,136,083	-1.5%	$21.03	17.1%	$15.92	16.1%	($4,543)	-262.0%	-2.7%	-341.2%	15	-16.7%
	Filtration	$485	$55	$98	1,143,167	-0.9%	$19.00	5.8%	$14.58	6.4%	($3,481)	-224.1%	-0.6%	-156.0%	16	-11.1%
$32/bbl	Baseline				1,163,124		$26.75		$13.73		$6,704		22.3%		22	
	Zero Discharge	$1,928	$97	$266	1,159,301	-0.3%	$30.15	12.7%	$16.20	17.9%	$4,668	-30.4%	17.1%	-23.4%	20	-9.1%
	Onshore Shallow	$1,711	$85	$235	1,159,301	-0.3%	$29.76	11.2%	$15.91	15.8%	$4,906	-26.8%	17.6%	-20.9%	20	-9.1%
	Filtration	$485	$55	$94	1,161,441	-0.1%	$27.78	3.8%	$14.61	6.4%	$5,989	-10.7%	20.6%	-7.7%	21	-4.5%

Note: BOE represents barrels-of-oil-equivalent.
Source: ERG estimates.

TABLE 7-23

NSPS POLLUTION CONTROL OPTIONS FOR PRODUCED WATER
MODEL PROJECT IMPACTS - SENSITIVITY ANALYSIS
GRANULAR FILTER COSTS

GULF OF MEXICO - GULF 12 PROJECT - OIL AND GAS PRODUCTION

		Pollution Control Costs			PV of Total Production (BOE)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Internal Rate of Return		Years of Production	
Sensitivity Analysis	Regulatory Scenario	Capital	O&M	Annualized	Data	Change	Data	Change	Data	Change	Data	Change	Data	Change	Data	Change
Baseline	Baseline				9,611,069		$18.23		$8.95		$33,610		20.1%		19	
	Zero Discharge	$1,598	$115	$242	9,611,069	0.0%	$18.56	1.8%	$9.20	2.8%	$31,883	-5.1%	19.3%	-3.8%	19	0.0%
	Onshore Shallow	$1,976	$94	$260	9,611,069	0.0%	$18.61	2.1%	$9.22	3.0%	$31,735	-5.6%	19.2%	-4.3%	19	0.0%
	Filtration	$990	$97	$171	9,611,069	0.0%	$18.45	1.2%	$9.13	2.0%	$32,401	-3.6%	19.6%	-2.5%	19	0.0%
$15/bbl	Baseline				9,539,096		$15.01		$8.92		$4,942		9.9%		17	
	Zero Discharge	$1,598	$115	$248	9,539,096	0.0%	$15.34	2.2%	$9.17	2.8%	$3,247	-34.3%	9.3%	-6.8%	17	0.0%
	Onshore Shallow	$1,976	$94	$267	9,539,096	0.0%	$15.40	2.6%	$9.19	3.0%	$3,093	-37.4%	9.2%	-7.5%	17	0.0%
	Filtration	$990	$97	$174	9,539,096	0.0%	$15.23	1.5%	$9.09	2.0%	$3,759	-23.9%	9.5%	-4.8%	17	0.0%
$32/bbl	Baseline				9,671,105		$23.85		$9.02		$83,863		35.6%		22	
	Zero Discharge	$1,598	$115	$238	9,655,652	-0.2%	$24.17	1.3%	$9.25	2.6%	$82,109	-2.1%	34.6%	-2.7%	21	-4.5%
	Onshore Shallow	$1,976	$94	$255	9,655,652	-0.2%	$24.22	1.6%	$9.27	2.8%	$81,966	-2.3%	34.5%	-3.1%	21	-4.5%
	Filtration	$990	$97	$169	9,655,652	-0.2%	$24.06	0.9%	$9.18	1.8%	$82,631	-1.5%	35.0%	-1.7%	21	-4.5%

Note: BOE represents barrels-of-oil-equivalent.
Source: ERG estimates.

TABLE 7-24

NSPS POLLUTION CONTROL OPTIONS FOR DRILLING FLUIDS, DRILL CUTTINGS, AND PRODUCED WATER
IMPACTS OF SELECTED COMBINATIONS OF REGULATORY OPTIONS

GULF OF MEXICO - GULF 1b AND GULF 12 OIL AND GAS PROJECTS

Project	Combined Options: Drilling Fluid/ Produced Water	PV of Total Production (BOE)		Corporate Cost per BOE		Production Cost per BOE		Net Present Value ($1000)		Internal Rate of Return		Years of Production	
		Data	Change	Data	Change	Data	Change	Data	Change	Data	Change	Data	Change
Gulf 1b	Baseline	1,159,301		$21.16		$13.71		$654		9.5%		20	
	4-Mile Barge/ G-Filter	1,153,130	-0.5%	$22.25	5.2%	$14.67	7.0%	($119)	-118.2%	7.7%	-18.9%	18	-10.0%
	4-Mile Barge/ M-Filter	1,153,130	-0.5%	$21.79	3.0%	$14.36	4.7%	$134	-79.5%	8.3%	-12.6%	18	-10.0%
	4-Mile Barge/ G-Zero Discharge	1,148,742	-0.9%	$24.64	16.4%	$16.26	18.6%	($1,421)	-317.3%	5.0%	-47.4%	17	-15.0%
	4-Mile Barge/ M-Zero Discharge	1,148,742	-0.9%	$23.88	12.9%	$15.75	14.9%	($1,005)	-253.7%	5.8%	-38.9%	17	-15.0%
	4-Mile Barge/ BPT	1,159,301	0.0%	$21.23	0.3%	$13.81	0.7%	$579	-11.5%	9.3%	-2.1%	20	0.0%
Gulf 12	Baseline	9,611,069		$18.23		$8.95		$33,610		20.1%		19	
	4-Mile Barge/ G-Filter	9,611,069	0.0%	$18.48	1.4%	$9.17	2.5%	$32,090	-4.5%	19.4%	-3.5%	19	0.0%
	4-Mile Barge/ M-Filter	9,611,069	0.0%	$18.38	0.8%	$9.11	1.8%	$32,560	-3.1%	19.7%	-2.0%	19	0.0%
	4-Mile Barge/ G-Zero Discharge	9,611,069	0.0%	$18.59	2.0%	$9.25	3.4%	$31,573	-6.1%	19.2%	-4.5%	19	0.0%
	4-Mile Barge/ M-Zero Discharge	9,611,069	0.0%	$18.44	1.2%	$9.15	2.2%	$32,280	-4.0%	19.5%	-3.0%	19	0.0%
	4-Mile Barge/ BPT	9,611,069	0.0%	$18.26	0.2%	$9.00	0.6%	$33,300	-0.9%	19.9%	-1.0%	19	0.0%

Notes: G refers to granular filter technology costs for injection and filtration.
M refers to membrane filter technology costs for injection and filtration.
BOE represents barrels-of-oil-equivalent.
Source: ERG estimates.

This relationship means that the effects of the combined pollution control options (one for drilling fluids and drill cuttings with one for produced water) on any of the projects can be determined by adding the appropriate entries provided earlier in this section.[2] Impacts will not exceed those for the Gulf 1b, and are likely to resemble or be less than those for the Gulf 12.

When the combined impacts are analyzed for a typical sized Gulf 12 project, the net present value decreases by no more than 6.1 percent and the internal rate of return decreases by no more than 4.5 percent under any combination of options. The corporate and production costs per BOE increase by about 40 cents under the most expensive combination of options. Under the combination of 4-Mile Barge; 1,1 Other requirements for drilling waste and filtration costs for produced water, the Gulf 12 shows no more than a 5 percent decline in net present value or the internal rate of return and a 25 cent increase in the corporate cost per BOE. Under the same combination of costs, the net present value for the Gulf 1b turns negative if granular filter costs are assumed but remains positive if membrane filter costs are assumed.

[2] Components may not sum precisely due to independent rounding.

SECTION EIGHT

IMPACTS ON REPRESENTATIVE COMPANIES

This section evaluates the financial impact of BAT effluent guidelines limitations and NSPS standards on (1) drilling fluids and drill cuttings and (2) production wastes from the offshore oil and gas industry. Impacts are considered three ways: (1) on the industry as a whole, (2) on a "typical" major oil company, and (3) on a "typical" independent oil company. The balance sheets and income statements for "typical" majors and independents are developed in Section Three. The compliance costs associated with regulations are presented in Section Six.

8.1 DRILLING FLUIDS AND DRILL CUTTINGS

The American Petroleum Institute conducts an annual survey on exploration, development, and production expenditures by the oil and gas industry. The data for 1986 and 1985 are presented in Table 8-1. The effects of the oil crash in 1986 are evident; exploration and development expenditures are approximately one-half of 1985 levels. Any comparison of annual compliance costs to 1986 expenditures is a conservative approach because of the low level of 1986 expenditures.

To examine the full range of potential impacts of increased pollution control costs, the Agency considered four alternative scenarios:

- $21/bbl - restricted development
- $21/bbl - unrestricted development
- $32/bbl - unrestricted development
- $15/bbl - restricted development

The baseline ("best estimate") impacts are represented by the cost borne under the first scenario ($21/bbl - restricted development). The third scenario ($32/bbl - unrestricted development) represents the upper estimate of impacts, while the fourth scenario ($15/bbl - restricted development) represents the spend.wk1

TABLE 8-1
OIL AND GAS EXPLORATION AND DEVELOPMENT EXPENDITURES ** - 1986 AND 1985 DATA

Parameter	1986 ($Million) Total	Onshore	Offshore	Alaska	1985 ($Million) Total	Onshore	Offshore	Alaska
Exploration								
Drilling & Equipping	$3,048	$1,904	$1,149	($5)	$9,297	$6,796	$2,154	$347
Acquiring Undeveloped Acreage	$1,335	$1,016	$270	$49	$4,040	$2,522	$1,478	$40
Land dept., leasing & Scouting	$301	$291	$7	$3	$381	$355	$16	$10
Geological & Geophysical	$1,244	$882	$306	$56	$2,392	$1,787	$430	$175
Lease Rents	$383	$300	$65	$18	$541	$444	$69	$28
Test Hole Contributions	$125	$117	$4	$4	$16	$4	$10	$2
Other*	$2,032	-	-	-	$2,732	-	-	-
Total Exploration Expenditures	$8,468	$4,510	$1,801	$125	$19,399	$11,908	$4,157	$602
Development								
Drilling & Equipping	$9,257	$6,460	$2,148	$649	$17,411	$14,076	$2,822	$513
Lease Equipment	$3,526	$1,455	$1,032	$1,039	$5,029	$2,004	$1,569	$1,456
Fluid Inj. & Impr. Recov.	$1,140	$875	$61	$204	$1,822	$1,372	$77	$373
Other*	$2,431	-	-	-	$2,974	-	-	-
Total Development Expenditures	$16,354	$8,790	$3,241	$1,892	$27,236	$17,452	$4,468	$2,342
Total Exploration & Development Expenditures	$24,822	$13,300	$5,042	$2,017	$46,635	$29,360	$8,625	$2,944

* Other includes direct overhead and G&A overhead; this category is not allocated among regions.
** Current dollars.
Source: 1986 API Survey on Oil & Gas Expenditures, American Petroleum Institute, December 1987.

lower estimate. The tables throughout Section 8.1 refer to these three scenarios as "baseline," "upper," and "lower," respectively.

8.1.1 Impacts on the General Offshore Oil and Gas Industry

Under the baseline case, the annual compliance costs for the regulatory options on drilling fluids and drill cuttings range from $1 million to $224 million in 1986 dollars. Compared to the expenditures allocated to offshore efforts for 1986 (see Table 8-1), the compliance costs would range from 0.02 percent to 4.4 percent of these expenditures. In comparison with 1985 data, the annual costs of compliance range from 0.01 percent to 2.6 percent of total offshore exploration and development expenditures.

8.1.2 Impacts on "Typical" Oil Companies

The costs of compliance borne by the industry will be financed by the oil and gas companies operating in the offshore areas. The financial impact of these expenditures for a given company depends on the size of the expenditures required and the current financial condition of the company. Since the price that a company can command for its oil is set by the world oil price and not domestic costs, the Agency assumes no increase in oil price to offset the cost of compliance.

To measure the impact of the cost of compliance on a representative major oil company, it is first necessary to estimate the portion of the annual costs that it would bear. The API survey on expenditures also presents the expenditures of the 19 largest companies, all but one of which are major oil companies. Unfortunately, the data are not subdivided by both "largest companies" and region, so it is not possible to obtain the expenditures by the largest companies in the offshore region. Table 8-2 presents the exploration and development expenditures in 1986 by the 19 largest companies. Each major oil company accounted for an average of $688 million out of a total of $24,822 million, or 2.77 percent of the national total exploration and development expenditures for the oil and gas industry.

In 1985, a "typical" independent oil company spent $69 million for domestic exploration and development, including both offshore and onshore efforts (see Table 3-27). (As mentioned in Section Three, it was not possible cost%.wk1

TABLE 8-2
EXPLORATION AND DEVELOPMENT EXPENDITURES BY MAJOR OIL COMPANIES IN 1986
(BOTH OFFSHORE AND ONSHORE)

Parameter	Total	19 Largest Companies	Remaining Companies
Exploration Expenditures	$8,468	$4,275	$4,193
Development Expenditures	$16,354	$8,793	$7,561
Sum of Exploration and Development Expenditures	$24,822	$13,068	$11,754
Average Expenditure For a Large Company		$688	

Note: All expenditures in millions of current dollars.

Source: 1986 Survey on Oil & Gas Expenditures, American Petroleum Institute, December 1987.

to update the income statement and balance sheet for 1986 for independents because of the take-over of Inexco by Louisiana Land & Exploration in mid-1986.) Thus a typical independent accounted for $69 million out of a total of $46,635 million or 0.15 percent of total domestic exploration and development expenditures in 1985 (see Table 8-1).

A typical major was assumed to bear 2.77 percent of the compliance costs while a typical independent would bear 0.15 percent of the costs. Table 8-3 lists the cost borne by a typical major and independent for each of the four scenarios analyzed.

The company is assumed to raise the entire amount at one time to finance compliance. Two financing alternatives were considered:

- All expenditures are financed by long-term debt.
- All expenditures are financed by working capital.

Tables 8-4 and 8-5 show the impact on the balance sheet of a typical major of financing effluent guidelines limitations and standards costs through long-term debt or working capital, respectively. The balance sheet for the unregulated case is developed in Section Three.

Table 8-6 lists the changes in working capital, current ratio, long-term debt-to-equity ratio, and debt-to-capital ratio caused by the cost of compliance. For the 1,1 All and 5,3 All options, no changes are seen for any of the parameters. For the options that require barging within 4 miles of shore, no changes are seen for three of the parameters, while working capital is reduced by 0.2 percent or less. Under the Zero Discharge option, working capital is reduced by 1.2 percent or less, while the other three parameters incur changes of 0.2 percent or less.

Dropping Inexco from the data set for 1986 would have left too few companies for aggregation. Therefore, to obtain a balance sheet for a "typical" independent for 1986, the change in the consumer price index was used to inflate the 1985 balance sheet to 1986 dollars. Tables 8-7 and 8-8 show the updated balance sheet and the impacts of financing the cost of compliance by working capital and long-term debt, respectively.

Table 8-9 lists the changes in working capital, current ratio, long-term debt-to-equity ratio, and debt-to-capital ratio caused by the cost of compliance. No change occurs to the current ratio, long-term-debt-to-equity, and debt-to-capital for a typical independent under the 1,1 All and 5,3 All

TABLE 8-3

ANNUAL COST OF POLLUTION CONTROL OPTIONS
DRILLING FLUIDS AND DRILL CUTTINGS
MILLIONS OF DOLLARS, 1986 DOLLARS

	Regulatory Options														
	Zero Discharge			4-Mile Barge; 1,1 Other			4-Mile Barge; 5,3 Other			1,1 All			5,3 All		
Scenario	Total Annual	Typical Major Portion	Typical Independent Portion	Total Annual	Typical Major Portion	Typical Independent Portion	Total Annual	Typical Major Portion	Typical Independent Portion	Total Annual	Typical Major Portion	Typical Independent Portion	Total Annual	Typical Major Portion	Typical Independent Portion
$21/bbl - Restricted	$224	$6.20	$0.34	$30	$0.83	$0.04	$23	$0.63	$0.03	$9	$0.25	$0.01	$1	$0.03	$0.00
$21/bbl - Unrestricted	$283	$7.85	$0.42	$50	$1.38	$0.07	$43	$1.18	$0.06	$11	$0.29	$0.02	$2	$0.05	$0.00
$32/bbl - Unrestricted	$344	$9.53	$0.52	$60	$1.65	$0.09	$51	$1.41	$0.08	$14	$0.40	$0.02	$4	$0.12	$0.01
$15/bbl - Restricted	$197	$5.46	$0.30	$26	$0.73	$0.04	$20	$0.56	$0.03	$8	$0.21	$0.01	$1	$0.02	$0.00

Source: ERG estimates.

TABLE 8-4

EFFLUENT GUIDELINES IMPACTS ON TYPICAL MAJOR OIL COMPANY
COMPLIANCE COSTS FINANCED BY WORKING CAPITAL
DRILLING FLUIDS AND DRILL CUTTINGS

$ MILLIONS, 1986 DOLLARS

		Regulatory Option														
		Zero Discharge			4-Mile Barge; 1,1 Other			4-Mile Barge; 5,3 Other			1,1 All			5,3 All		
Parameters	1986 Dollars	Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower
Regulatory Cost Borne by Major		$6.20	$9.53	$5.46	$0.83	$1.65	$0.73	$0.63	$1.41	$0.56	$0.25	$0.40	$0.21	$0.03	$0.12	$0.02
Assets																
Current Assets	$8,337	$8,331	$8,327	$8,332	$8,336	$8,335	$8,336	$8,336	$8,336	$8,336	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337
Property, Plant, and Equipment (Net)	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799
Other Assets	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758
Total Assets	$35,893	$35,888	$35,884	$35,889	$35,893	$35,892	$35,893	$35,893	$35,893	$35,893	$35,894	$35,894	$35,894	$35,894	$35,894	$35,894
Liabilities																
Current Liabilities	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536
Long-term Debt	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443
Other Liabilities (a)	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600
Total Liabilities	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579
Shareholders' Equity	$15,314	$15,308	$15,304	$15,309	$15,313	$15,312	$15,313	$15,313	$15,313	$15,313	$15,314	$15,314	$15,314	$15,314	$15,314	$15,314
Total Liabilities and Net Worth	$35,893	$35,887	$35,883	$35,888	$35,892	$35,891	$35,892	$35,892	$35,892	$35,892	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893

Note:(a) Other liabilities include: deferred Federal and foreign income taxes, deferred revenue, production payments, and other medium-term commitments.
Baseline refers to $21/bbl - Restricted.
Upper refers to $32/bbl - Unrestricted.
Lower refers to $15/bbl - Restricted.
Entries may not sum due to independent rounding.

Source: ERG estimates.

TABLE 8-5

EFFLUENT GUIDELINES IMPACTS ON TYPICAL MAJOR OIL COMPANY
COMPLIANCE COSTS FINANCED BY LONG-TERM DEBT
DRILLING FLUIDS AND DRILL CUTTINGS

$ MILLIONS, 1986 DOLLARS

		Regulatory Option														
		Zero Discharge			4-Mile Barge; 1,1 Other			4-Mile Barge; 5,3 Other			1,1 All			5,3 All		
Parameters	1986 Dollars	Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower
Regulatory Cost Borne by Major		$6.20	$9.53	$5.46	$0.83	$1.65	$0.73	$0.63	$1.41	$0.56	$0.25	$0.40	$0.21	$0.03	$0.12	$0.02
Assets																
Current Assets	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337	$8,337
Property, Plant, and Equipment (Net)	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799	$24,799
Other Assets	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758	$2,758
Total Assets	$35,893	$35,894	$35,894	$35,894	$35,894	$35,894	$35,894	$35,894	$35,894	$35,894	$35,894	$35,894	$35,894	$35,894	$35,894	$35,894
Liabilities																
Current Liabilities	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536	$7,536
Long-term Debt	$5,443	$5,449	$5,453	$5,448	$5,444	$5,445	$5,444	$5,444	$5,444	$5,444	$5,443	$5,443	$5,443	$5,443	$5,443	$5,443
Other Liabilities (a)	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600	$7,600
Total Liabilities	$20,579	$20,585	$20,589	$20,584	$20,580	$20,581	$20,580	$20,580	$20,580	$20,580	$20,579	$20,579	$20,579	$20,579	$20,579	$20,579
Shareholders' Equity	$15,314	$15,308	$15,304	$15,309	$15,313	$15,312	$15,313	$15,313	$15,313	$15,313	$15,314	$15,314	$15,314	$15,314	$15,314	$15,314
Total Liabilities and Net Worth	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893	$35,893

Note:(a) Other liabilities include: deferred Federal and foreign income taxes, deferred revenue, production payments, and other medium-term commitments.
Baseline refers to $21/bbl - Restricted.
Upper refers to $32/bbl - Unrestricted.
Lower refers to $15/bbl - Restricted.
Entries may not sum due to independent rounding.
Source: ERG estimates.

TABLE 8-6

CHANGES IN FINANCIAL RATIOS FOR A TYPICAL MAJOR AS A RESULT OF EFFLUENT GUIDELINES REGULATIONS
DRILLING FLUIDS AND DRILL CUTTINGS

	No Regulation		Regulatory Option									
			Zero Discharge		4-Mile Barge; 1,1 Other		4-Mile Barge; 5,3 Other		1,1 All		5,3 All	
Parameters	1986 Dollars	Scenario	Parameter	% Change	Parameter	% Change	Parameter	% Change	Parameter	% Change	Parameter	% Change
Working Capital (a) ($M)	$801	Baseline	$795	-0.8%	$800	-0.1%	$800	-0.1%	$801	-0.0%	$801	-0.0%
		Upper	$791	-1.2%	$799	-0.2%	$800	-0.2%	$801	-0.0%	$801	-0.0%
		Lower	$796	-0.7%	$800	-0.1%	$800	-0.1%	$801	-0.0%	$801	-0.0%
Current Ratio (a)	1.11	Baseline	1.11	-0.1%	1.11	-0.0%	1.11	-0.0%	1.11	-0.0%	1.11	-0.0%
		Upper	1.11	-0.1%	1.11.	-0.0%	1.11	-0.0%	1.11	-0.0%	1.11	-0.0%
		Lower	1.11	-0.1%	1.11	-0.0%	1.11	-0.0%	1.11	-0.0%	1.11	-0.0%
Long-term Debt to Equity (b) (%)	35.5%	Baseline	35.6%	0.2%	35.5%	0.0%	35.5%	0.0%	35.5%	0.0%	35.5%	0.0%
		Upper	35.6%	0.2%	35.6%	0.0%	35.6%	0.0%	35.5%	0.0%	35.5%	0.0%
		Lower	35.6%	0.1%	35.5%	0.0%	35.5%	0.0%	35.5%	0.0%	35.5%	0.0%
Debt to Capital (b) (%)	23.8%	Baseline	23.9%	0.1%	23.8%	0.0%	23.8%	0.0%	23.8%	0.0%	23.8%	0.0%
		Upper	23.9%	0.2%	23.8%	0.0%	23.8%	0.0%	23.8%	0.0%	23.8%	0.0%
		Lower	23.9%	0.1%	23.8%	0.0%	23.8%	0.0%	23.8%	0.0%	23.8%	0.0%

Note: (a) These ratios affected by working capital approach only.
(b) These ratios affected by debt financing approach only.
Baseline refers to $21/bbl - Restricted.
Upper refers to $32/bbl - Unrestricted.
Lower refers to $15/bbl - Restricted.

Source: ERG estimates.

TABLE 8-7

EFFLUENT GUIDELINES IMPACTS ON TYPICAL INDEPENDENT OIL COMPANY
COMPLIANCE COSTS FINANCED BY WORKING CAPITAL
DRILLING FLUIDS AND DRILL CUTTINGS

$ MILLIONS, 1986 DOLLARS

Parameters	1985 Dollars	1986 Dollars	Regulatory Option: Zero Discharge			4-Mile Barge; 1,1 Other			4-Mile Barge; 5,3 Other			1,1 All			5,3 All		
			Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower
Regulatory Cost Borne by Independent			$0.34	$0.52	$0.30	$0.04	$0.09	$0.04	$0.03	$0.08	$0.03	$0.01	$0.02	$0.01	$0.00	$0.01	$0.00
Assets																	
Current Assets	$53	$55	$55	$54	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55
Property, Plant, and Equipment (Net)	$528	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547
Other Assets	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
Total Assets	$583	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605
Liabilities																	
Current Liabilities	$49	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51
Long-term Debt	$268	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278
Other Liabilities (a)	$108	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112
Total Liabilities	$424	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441
Shareholders' Equity	$159	$165	$164	$164	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165
Total Liabilities and Net Worth	$583	$604	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605

Notes: (a) Other liabilities include: deferred Federal and foreign income taxes, deferred revenue, production payments, and other medium-term commitments.
1985 dollars inflated to 1986 dollars by 3.65% based on change in Consumer Price Index.
Baseline refers to $21/bbl - Restricted.
Upper refers to $32/bbl - Unrestricted.
Lower refers to $15/bbl - Restricted.
Entries may not sum due to independent rounding.

Source: ERG estimates.

TABLE 8-8

EFFLUENT GUIDELINES IMPACTS ON TYPICAL INDEPENDENT OIL COMPANY
COMPLIANCE COSTS FINANCED BY LONG-TERM DEBT
DRILLING FLUIDS AND DRILL CUTTINGS

$ MILLIONS, 1986 DOLLARS

			Regulatory Option														
			Zero Discharge			4-Mile Barge; 1,1 Other			4-Mile Barge; 5,3 Other			1,1 All			5,3 All		
Parameters	1985 Dollars	1986 Dollars	Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower	Baseline	Upper	Lower
Regulatory Cost Borne by Independent			$0.34	$0.52	$0.30	$0.04	$0.09	$0.04	$0.03	$0.08	$0.03	$0.01	$0.02	$0.01	$0.00	$0.01	$0.00
Assets																	
Current Assets	$53	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55
Property, Plant, and Equipment (Net)	$528	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547	$547
Other Assets	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
Total Assets	$583	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605
Liabilities																	
Current Liabilities	$49	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51	$51
Long-term Debt	$268	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278	$278
Other Liabilities (a)	$108	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112	$112
Total Liabilities	$424	$439	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441	$441
Shareholders' Equity	$159	$165	$164	$164	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165
Total Liabilities and Net Worth	$583	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605	$605

Notes: (a) Other liabilities include: deferred Federal and foreign income taxes, deferred revenue, production payments, and other medium-term commitments.
1985 dollars inflated to 1986 dollars by 3.65% based on change in Consumer Price Index.
Baseline refers to $21/bbl - Restricted.
Upper refers to $32/bbl - Unrestricted.
Lower refers to $15/bbl - Restricted.
Entries may not sum due to independent rounding.

Source: ERG estimates.

TABLE 8-9

CHANGES IN FINANCIAL RATIOS FOR A TYPICAL INDEPENDENT AS A RESULT OF EFFLUENT GUIDELINES REGULATIONS
DRILLING FLUIDS AND DRILL CUTTINGS

	No Regulation		Regulatory Option									
			Zero Discharge		4-Mile Barge; 1,1 Other		4-Mile Barge; 5,3 Other		1,1 All		5,3 All	
Parameters	1986 Dollars	Scenario	Parameter	% Change	Parameter	% Change	Parameter	% Change	Parameter	% Change	Parameter	% Change
Working Capital (a) ($M)	$4.15	Baseline	$3.81	-8.2%	$4.11	-1.0%	$4.12	-0.7%	$4.14	-0.2%	$4.15	0.0%
		Upper	$3.63	-12.5%	$4.06	-2.2%	$4.07	-1.9%	$4.13	-0.5%	$4.14	-0.2%
		Lower	$3.85	-7.2%	$4.11	-1.0%	$4.12	-0.7%	$4.14	-0.2%	$4.15	0.0%
Current Ratio (a)	1.08	Baseline	1.07	-0.6%	1.08	-0.1%	1.08	-0.1%	1.08	-0.0%	1.08	0.0%
		Upper	1.07	-0.9%	1.08	-0.2%	1.08	-0.1%	1.08	-0.0%	1.08	-0.0%
		Lower	1.08	-0.5%	1.08	-0.1%	1.08	-0.1%	1.08	-0.0%	1.08	0.0%
Long-term Debt to Equity (b) (%)	168.6%	Baseline	169.1%	0.3%	168.6%	0.0%	168.6%	0.0%	168.6%	0.0%	168.6%	0.0%
		Upper	169.4%	0.5%	168.7%	0.1%	168.7%	0.1%	168.6%	0.0%	168.6%	0.0%
		Lower	169.0%	0.3%	168.6%	0.0%	168.6%	0.0%	168.6%	0.0%	168.6%	0.0%
Debt to Capital (b) (%)	128.8%	Baseline	129.2%	0.3%	128.9%	0.0%	128.9%	0.0%	128.9%	0.0%	128.8%	0.0%
		Upper	129.4%	0.4%	128.9%	0.1%	128.9%	0.1%	128.9%	0.0%	128.9%	0.0%
		Lower	129.2%	0.2%	128.9%	0.0%	128.9%	0.0%	128.9%	0.0%	128.8%	0.0%

Note: (a) These ratios affected by working capital approach only.
(b) These ratios affected by debt financing approach only.
Baseline refers to $21/bbl - Restricted.
Upper refers to $32/bbl - Unrestricted.
Lower refers to $15/bbl - Restricted.

Source: ERG estimates.

options. Working capital decreases by 0.5 percent or less. For the options where barging is required for operations within 4 miles of shore, current ratio, long-term-debt-to-equity, and debt-to-capital change by 0.2 percent or less. Working capital may decrease by as much as 2.2 percent. For the Zero Discharge option, debt financing ratios may increase by 0.5 percent, while the current ratio may decrease by 0.9 percent. Working capital may decrease by as much as 12.5 percent for the Zero Discharge option.

8.2 PRODUCED WATER - BAT

8.2.1 Impacts on the General Offshore Industry

The annualized cost for BAT controls on produced water range from $41 million to $845 million in 1986 dollars, assuming costs for granular filter filtration and injection. The annualized cost ranges from $13 million to $491 million in 1986 dollars for the same set of regulatory options, but assuming membrane filter costs for filtration and injection.

Looking strictly at the expenditures allocated to offshore efforts for 1986 (see Table 8-1), the compliance costs would range from 0.8 to 16.8 percent of the total for granular filter costs and from 0.3 to 9.7 percent for membrane filter costs. In comparison with the total offshore exploration and development expenditures in 1985, the annual compliance costs range from 0.5 to 9.8 percent for the granular filter costs, and from 0.2 to 5.7 percent assuming membrane filter costs.

8.2.2 Impacts on "Typical" Oil Companies

The same balance sheets shown in Tables 8-4, 8-5, 8-7 and 8-8 for a typical major and independent are used to evaluate the impacts of increased BAT pollution control costs for produced water on representative companies. As described in Section Six, there are two sets of costs for filtration and injection, so two financial ratio analyses are presented for each company.

Table 8-10 summarizes the portion of regulatory cost borne by a typical major and independent under both cost scenarios (granular filter and membrane filter). Using these costs from Table 8-10, the changes in financial ratios

TABLE 8-10

ANNUAL COST OF POLLUTION CONTROL OPTIONS
BAT PRODUCED WATER
MILLIONS OF DOLLARS, 1986 DOLLARS

$21/bbl

	Regulatory Options								
	Zero Discharge			All Filter			4-Mile Filter; BPT Other		
Cost Scenario	Total Annual	Typical Major Portion	Typical Independent Portion	Total Annual	Typical Major Portion	Typical Independent Portion	Total Annual	Typical Major Portion	Typical Independent Portion
Granular Filter Costs	$845	$23.40	$1.27	$480	$13.30	$0.72	$41	$1.14	$0.06
Membrane Filter Costs	$491	$13.61	$0.74	$151	$4.18	$0.23	$13	$0.36	$0.02

Source: ERG estimates.

were calculated for a typical major (Table 8-11) and for a typical independent (Table 8-12).

For a typical major under the 4-Mile Filter; BPT Other option, the working capital declines by 0.1 percent or less, depending upon filtration type (see Table 8-11). For the All Filter option, working capital declines by 1.7 percent, assuming granular filter costs and by 0.5 percent, assuming membrane filter costs. Changes in the current, long-term debt-to-equity, and debt-to-capital ratios are no more than 0.3 percent for the All Filter option. If a typical major must comply with the Zero Discharge option for BAT-produced water, working capital declines by 2.9 percent or 1.7 percent under the granular or membrane filter costs, respectively. The current ratio declines by no more than 0.3 percent, and the debt ratios increase by no more than 0.6 percent under the Zero Discharge option with granular filter costs.

Table 8-12 displays the impacts on a typical independent. Under the 4-Mile Filter; BPT Other option, working capital declines by 1.4 percent and 0.5 percent assuming granular filter and membrane filter costs, respectively. Changes in the other ratios are no more than 0.1 percent. Working capital declines by 17.4 or 5.5 percent for granular and membrane filter costs, respectively. Changes in the current ratio, long-term debt-to-equity, and debt-to-capital ratios range from 0.6 to 1.3 percent for granular filter costs and from 0.2 to 0.4 percent for membrane filter costs. Under the Zero Discharge option, working capital declines by 30.6 percent for granular filter costs and by 17.8 percent for membrane filter costs. Changes in the other ratios range from 1.1 to 2.3 percent and 0.6 to 1.3 percent for the granular and membrane filter costs, respectively.

8.3 PRODUCED WATER - NSPS

8.3.1 Impacts on the General Offshore Industry

The annualized cost in the year 2000 for NSPS controls on produced water ranges from $11 million to $158 million in 1986 dollars, assuming membrane filter costs for filtration and injection. The annualized cost ranges from $16 million to $206 million in 1986 dollars for the same set of regulatory options, but assuming granular filter costs for filtration and injection.

TABLE 8-11

CHANGES IN FINANCIAL RATIOS FOR A TYPICAL MAJOR AS A RESULT OF EFFLUENT GUIDELINES REGULATIONS
BAT PRODUCED WATER

			Regulatory Option					
			Zero Discharge		All Filter		4-Mile Filter; BPT Other	
Parameters	No Regulation 1986 Dollars	Cost Scenario	Parameter	% Change	Parameter	% Change	Parameter	% Change
Working Capital (a) ($M)	$801	Granular	$778	-2.9%	$788	-1.7%	$800	-0.1%
		Membrane	$787	-1.7%	$797	-0.5%	$801	-0.0%
Current Ratio (a)	1.11	Granular	1.10	-0.3%	1.10	-0.2%	1.11	-0.0%
		Membrane	1.10	-0.2%	1.11	-0.1%	1.11	-0.0%
Long-term Debt to Equity (b) (%)	35.5%	Granular	35.8%	0.6%	35.7%	0.3%	35.6%	0.0%
		Membrane	35.7%	0.3%	35.6%	0.1%	35.5%	0.0%
Debt to Capital (b) (%)	23.8%	Granular	23.9%	0.5%	23.9%	0.3%	23.8%	0.0%
		Membrane	23.9%	0.3%	23.8%	0.1%	23.8%	0.0%

Note: (a) These ratios affected by working capital approach only.
(b) These ratios affected by debt financing appraoch only.

Source: ERG estimates.

TABLE 8-12

CHANGES IN FINANCIAL RATIOS FOR A TYPICAL INDEPENDENT AS A RESULT OF EFFLUENT GUIDELINES REGULATIONS
BAT PRODUCED WATER

			Regulatory Option					
	No Regulation	Cost	Zero Discharge		All Filter		4-Mile Filter; BPT Other	
Parameters	1986 Dollars	Scenario	Parameter	% Change	Parameter	% Change	Parameter	% Change
Working Capital (a) ($M)	$4.15	Granular Filter	$2.88	-30.6%	$3.43	-17.4%	$4.09	-1.4%
		Membrane Filter	$3.41	-17.8%	$3.92	-5.5%	$4.13	-0.5%
Current Ratio (a)	1.08	Granular Filter	1.06	-2.3%	1.07	-1.3%	1.08	-0.1%
		Membrane Filter	1.07	-1.3%	1.08	-0.4%	1.08	-0.0%
Long-term Debt to Equity (b) (%)	168.6%	Granular Filter	170.6%	1.2%	169.7%	0.7%	168.7%	0.1%
		Membrane Filter	169.8%	0.7%	168.9%	0.2%	168.6%	0.0%
Debt to Capital (b) (%)	128.8%	Granular Filter	130.2%	1.1%	129.6%	0.6%	128.9%	0.0%
		Membrane Filter	129.6%	0.6%	129.1%	0.2%	128.9%	0.0%

Note: (a) These ratios affected by working capital approach only.
(b) These ratios affected by debt financing approach only.

Source: ERG estimates.

Looking strictly at the expenditures allocated to offshore efforts for 1986 (see Table 8-1), the compliance costs would range from 0.3 to 4.1 percent of the total for granular filter costs and from 0.2 to 3.1 percent for membrane filter costs. In comparison with the total offshore exploration and development expenditures in 1985, the annual compliance costs range from 0.2 to 2.4 percent for the granular filter costs, and from 0.1 to 1.8 percent assuming membrane filter costs.

8.3.2 Impacts on "Typical" Oil Companies

Table 8-13 lists the portion of NSPS-produced water pollution control costs borne by a typical major and independent under three cost scenarios. The "baseline" scenario assumes $21/bbl, restricted development, and membrane filter costs, and represents the most reasonable estimate of projection costs. The "upper" cost scenario, representing the high estimate of projected costs, assumes $32/bbl and unrestricted development with granular filter costs. The "lower" cost scenario assumes $15/bbl with restricted development and membrane filter costs.

Table 8-14 summarizes the change in financial ratios for a <u>typical major</u>. The largest change is seen in working capital under the $32/bbl oil price scenario; the change, however, is only 1.3 percent. The financial ratio analysis for a <u>typical independent</u> is given in Table 8-15. Current ratio, long-term debt-to-equity, and debt-to-capital all change by no more than 1 percent under any of the options. Working capital shows a large range in response, declining by no more than 2 percent under the 4-Mile Filter; BPT Other option and from 5 to 14 percent under the Zero Discharge option.

8.4 COMBINED EFFECTS OF SELECTED REGULATORY OPTIONS

8.4.1 Impacts on the General Offshore Oil and Gas Industry

Six combinations of regulatory options were analyzed. Table 8-16 presents the combinations and their costs. Two sets of costs are provided, depending upon whether development is restricted or unrestricted. The oil price in both cases is assumed to be $21/bbl.

TABLE 8-13

ANNUAL COST OF POLLUTION CONTROL OPTIONS
NSPS PRODUCED WATER
MILLIONS OF DOLLARS, 1986 DOLLARS

$21/bbl

	Regulatory Options								
	Zero Discharge			All Filter			4-Mile Filter; BPT Other		
Cost Scenario	Total Annual	Typical Major Portion	Typical Independent Portion	Total Annual	Typical Major Portion	Typical Independent Portion	Total Annual	Typical Major Portion	Typical Independent Portion
Baseline	$158	$4.39	$0.24	$62	$1.70	$0.09	$11	$0.30	$0.02
Upper	$375	$10.40	$0.56	$168	$4.66	$0.25	$51	$1.42	$0.08
Lower	$135	$3.74	$0.20	$53	$1.46	$0.08	$8	$0.22	$0.01

Notes: Baseline refers to $21/bbl - Restricted w/ membrane filter costs.
Upper refers to $32/bbl - Unrestricted w/ granular filter costs.
Lower refers to $15/bbl - Restricted w/ membrane filter costs.

Source: ERG estimates.

TABLE 8-14

CHANGES IN FINANCIAL RATIOS FOR A TYPICAL MAJOR AS A RESULT OF EFFLUENT GUIDELINES REGULATIONS
NSPS PRODUCED WATER

Parameters	No Regulation 1986 Dollars	Cost Scenario	Regulatory Option: Zero Discharge		All Filter		4-Mile Filter; BPT Other	
			Parameter	% Change	Parameter	% Change	Parameter	% Change
Working Capital (a) ($M)	$801	Baseline	$797	-0.5%	$799	-0.2%	$801	-0.0%
		Upper	$791	-1.3%	$796	-0.6%	$800	-0.2%
		Lower	$797	-0.5%	$800	-0.2%	$801	-0.0%
Current Ratio (a)	1.11	Baseline	1.11	-0.1%	1.11	-0.0%	1.11	-0.0%
		Upper	1.10	-0.1%	1.11	-0.1%	1.11	-0.0%
		Lower	1.11	-0.0%	1.11	-0.0%	1.11	-0.0%
Long-term Debt to Equity (b) (%)	35.5%	Baseline	35.6%	0.1%	35.6%	0.0%	35.5%	0.0%
		Upper	35.6%	0.3%	35.6%	0.1%	35.6%	0.0%
		Lower	35.6%	0.1%	35.6%	0.0%	35.5%	0.0%
Debt to Capital (b) (%)	23.8%	Baseline	23.8%	0.1%	23.8%	0.0%	23.8%	0.0%
		Upper	23.9%	0.2%	23.8%	0.1%	23.8%	0.0%
		Lower	23.8%	0.1%	23.8%	0.0%	23.8%	0.0%

Notes: (a) These ratios affected by working capital approach only.
(b) These ratios affected by debt financing approach only.
Baseline refers to $21/bbl - Restricted w/ membrane filter costs.
Upper refers to $32/bbl - Unrestricted w/ granular filter costs.
Lower refers to $15/bbl - Restricted w/ membrane filter costs.

Source: ERG estimates.

TABLE 8-15

CHANGES IN FINANCIAL RATIOS FOR A TYPICAL INDEPENDENT AS A RESULT OF EFFLUENT GUIDELINES REGULATIONS
NSPS PRODUCED WATER

			Regulatory Option					
	No Regulation		Zero Discharge		All Filter		4-Mile Filter; BPT Other	
Parameters	1986 Dollars	Scenario	Parameter	% Change	Parameter	% Change	Parameter	% Change
Working Capital (a) ($M)	$4.15	Baseline	$3.91	-5.7%	$4.05	-2.2%	$4.13	-0.4%
		Upper	$3.58	-13.6%	$3.89	-6.1%	$4.07	-1.9%
		Lower	$3.95	-4.8%	$4.07	-1.9%	$4.14	-0.2%
Current Ratio (a)	1.08	Baseline	1.08	-0.4%	1.08	-0.2%	1.08	-0.0%
		Upper	1.07	-1.0%	1.08	-0.5%	1.08	-0.1%
		Lower	1.08	-0.4%	1.08	-0.1%	1.08	-0.0%
Long-term Debt to Equity (b) (%)	168.6%	Baseline	168.9%	0.2%	168.7%	0.1%	168.6%	0.0%
		Upper	169.5%	0.5%	169.0%	0.2%	168.7%	0.1%
		Lower	168.9%	0.2%	168.7%	0.1%	168.6%	0.0%
Debt to Capital (b) (%)	128.8%	Baseline	129.1%	0.2%	128.9%	0.1%	128.9%	0.0%
		Upper	129.4%	0.5%	129.1%	0.2%	128.9%	0.1%
		Lower	129.1%	0.2%	128.9%	0.1%	128.9%	0.0%

Notes: (a) These ratios affected by working capital approach only.
(b) These ratios affected by debt financing approach only.
Baseline refers to $21/bbl - Restricted w/ membrane filter costs.
Upper refers to $32/bbl - Unrestricted w/ granular filter costs.
Lower refers to $15/bbl - Restricted w/ membrane filter costs.

Source: ERG estimates.

TABLE 8-16

COMBINED COST OF SELECTED REGULATORY PACKAGES
$MILLIONS, 1986 DOLLARS

Regulatory Package	Effluent	Effluent Control Option	Restricted Development: Total Annual Cost	Restricted Development: Portion Borne by Typical Major	Restricted Development: Portion Borne by Typical Independent	Unrestricted Development: Total Annual Cost	Unrestricted Development: Portion Borne by Typical Major	Unrestricted Development: Portion Borne by Typical Independent
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$0.83	$0.04	$50	$1.38	$0.07
	Produced Water - BAT	4-Mile Filter; BPT Other	$41	$1.14	$0.06	$41	$1.14	$0.06
	Produced Water - NSPS	4-Mile Filter; BPT Other	$16	$0.46	$0.02	$27	$0.75	$0.04
	Combined Cost		$88	$2.43	$0.13	$118	$3.28	$0.18
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$0.83	$0.04	$50	$1.38	$0.07
	Produced Water - BAT	Zero Discharge	$845	$23.40	$1.27	$845	$23.40	$1.27
	Produced Water - NSPS	Zero Discharge	$206	$5.71	$0.31	$275	$7.62	$0.41
	Combined Cost		$1,081	$29.94	$1.62	$1,170	$32.40	$1.75
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$0.83	$0.04	$50	$1.38	$0.07
	Produced Water - BAT	All Filter	$480	$13.30	$0.72	$480	$13.30	$0.72
	Produced Water - NSPS	All Filter	$95	$2.63	$0.14	$128	$3.53	$0.19
	Combined Cost		$605	$16.75	$0.91	$657	$18.21	$0.99
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$0.83	$0.04	$50	$1.38	$0.07
	Produced Water - BAT	All Filter - Membrane	$151	$4.18	$0.23	$151	$4.18	$0.23
	Produced Water - NSPS	All Filter - Membrane	$62	$1.70	$0.09	$81	$2.24	$0.12
	Combined Cost		$242	$6.71	$0.36	$282	$7.80	$0.42
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$0.83	$0.04	$50	$1.38	$0.07
	Produced Water - BAT	BPT All	$0	$0.00	$0.00	$0	$0.00	$0.00
	Produced Water - NSPS	BPT All	$0	$0.00	$0.00	$0	$0.00	$0.00
	Combined Cost		$30	$0.83	$0.04	$50	$1.38	$0.07
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$0.83	$0.04	$50	$1.38	$0.07
	Produced Water - BAT	4-Mile Filter; BPT Other -Mem	$13	$0.36	$0.02	$13	$0.36	$0.02
	Produced Water - NSPS	4-Mile Filter; BPT Other -Mem	$11	$0.30	$0.02	$17	$0.47	$0.03
	Combined Cost		$54	$1.48	$0.08	$80	$2.21	$0[illegible]2

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filter technology. Entries may not sum due to independent rounding.

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement, but must comply with the 1,1 All restrictions.

Source: ERG estimates.

Under the restricted development assumption, total compliance costs range from $30 million to $1,081 million (1986 dollars). This cost represents 0.6 to 21.4 percent of the industry expenditures for offshore exploration and development in 1986 (see Table 8-1). The total costs represent 0.4 to 12.5 percent of offshore expenditures in 1985.

Assuming unrestricted development, the total compliance costs range from $50 million to $1,170 million (1986 dollars), approximately 1 to 23 percent of the 1986 offshore expenditures. Compared to offshore expenditures in 1985, compliance costs range from 0.6 to 13.6 percent of the total.

8.4.2 Impacts on "Typical" Oil Companies

Table 8-17 summarizes the impacts of pollution control packages on a typical major oil company. If working capital is used to finance the increased pollution control costs, a decline of 0.1 to 3.7 percent in working capital is expected (assuming restricted development). The 3.7 percent decline is seen under regulatory package B (4-Mile Barge; 1,1 Other for drilling wastes; Zero Discharge for produced water). The current ratio decreases by no more than 0.4 percent. The financial ratios affected by debt-financing increase by no more than 0.7 percent under any of the regulatory packages assuming restricted development. Working capital for a typical major declines by no more than 4 percent under the unrestricted development scenario in any package. All other ratios change by less than 1 percent. For regulatory package F (4-Mile Barge; 1,1 Other for drilling fluids and 4-Mile Filter; BPT Other for produced water), all financial ratios for a typical major change by no more than 0.3 percent.

Table 8-18 summarizes the changes in financial ratios for a typical independent oil company under the six regulatory packages. The greatest impacts occur when working capital is used to finance the additional pollution control costs. Assuming restricted development, working capital declines by 39.1 percent under package B, 21.9 percent under package C, and between 1.1 and 8.8 percent for the other packages. The current ratio declines by 3.0 percent under package B and 1.7 percent or less under the other packages. The financial ratios affected by debt-financing increase by 1.6 percent and 1.3 percent under package B for the long-term debt-to-equity and debt-to-capital ratios, respectively. Under the other packages, the ratios increase by no more than 0.8 percent. Impacts for package F (4-Mile Barge; 1,1 Other for drilling wastes and 4-Mile Filter; BPT Other for produced water) show only a 2

TABLE 8-17

CHANGES IN FINANCIAL RATIOS FOR A TYPICAL MAJOR AS A RESULT OF EFFLUENT GUIDELINES REGULATIONS
SELECTED COMBINATIONS OF REGULATORY OPTIONS

Parameters	No Regulation 1986 Dollars	Regulatory Package	Change in Financial Ratios: Restricted Parameter	Restricted % Change	Unrestricted Parameter	Unrestricted % Change
Working Capital (a) ($M)	$801	A	$799	-0.3%	$798	-0.4%
		B	$771	-3.7%	$769	-4.0%
		C	$784	-2.1%	$783	-2.3%
		D	$794	-0.8%	$793	-1.0%
		E	$800	-0.1%	$800	-0.2%
		F	$800	-0.2%	$799	-0.3%
Current Ratio (a)	1.11	A	1.11	-0.0%	1.11	-0.0%
		B	1.10	-0.4%	1.10	-0.4%
		C	1.10	-0.2%	1.10	-0.2%
		D	1.11	-0.1%	1.11	-0.1%
		E	1.11	-0.0%	1.11	-0.0%
		F	1.11	-0.0%	1.11	-0.0%
Long-term Debt to Equity (b) (%)	35.5%	A	35.6%	0.1%	35.6%	0.1%
		B	35.8%	0.7%	35.8%	0.8%
		C	35.7%	0.4%	35.7%	0.5%
		D	35.6%	0.2%	35.6%	0.2%
		E	35.5%	0.0%	35.6%	0.0%
		F	35.6%	0.0%	35.6%	0.1%
Debt to Capital (b) (%)	23.8%	A	23.8%	0.1%	23.8%	0.1%
		B	24.0%	0.7%	24.0%	0.7%
		C	23.9%	0.4%	23.9%	0.4%
		D	23.9%	0.2%	23.9%	0.2%
		E	23.8%	0.0%	23.8%	0.0%
		F	23.8%	0.0%	23.8%	0.1%

Note: (a) These ratios affected by working capital approach only.
(b) These ratios affected by debt financing approach only.
Source: ERG estimates.

TABLE 8-18

CHANGES IN FINANCIAL RATIOS FOR A TYPICAL INDEPENDENT AS A RESULT OF EFFLUENT GUIDELINES REGULATIONS
SELECTED COMBINATIONS OF REGULATORY OPTIONS

			Change in Financial Ratios			
			Restricted		Unrestricted	
Parameters	No Regulation 1986 Dollars	Regulatory Package	Parameter	% Change	Parameter	% Change
Working Capital (a) ($M)	$4.15	A	$4.01	-3.2%	$3.97	-4.3%
		B	$2.52	-39.1%	$2.39	-42.3%
		C	$3.24	-21.9%	$3.16	-23.8%
		D	$3.78	-8.8%	$3.72	-10.2%
		E	$4.10	-1.1%	$4.07	-1.8%
		F	$4.07	-1.9%	$4.03	-2.9%
Current Ratio (a)	1.08	A	1.08	-0.2%	1.08	-0.3%
		B	1.05	-3.0%	1.05	-3.2%
		C	1.06	-1.7%	1.06	-1.8%
		D	1.07	-0.7%	1.07	-0.8%
		E	1.08	-0.1%	1.08	-0.1%
		F	1.08	-0.1%	1.08	-0.2%
Long-term Debt to Equity (b) (%)	168.6%	A	168.8%	0.1%	168.8%	0.2%
		B	171.2%	1.6%	171.4%	1.7%
		C	170.0%	0.9%	170.2%	1.0%
		D	169.1%	0.4%	169.2%	0.4%
		E	168.6%	0.0%	168.7%	0.1%
		F	168.7%	0.1%	168.7%	0.1%
Debt to Capital (b) (%)	128.8%	A	129.0%	0.1%	129.0%	0.1%
		B	130.6%	1.3%	130.7%	1.5%
		C	129.8%	0.8%	129.9%	0.8%
		D	129.2%	0.3%	129.3%	0.3%
		E	128.9%	0.0%	128.9%	0.1%
		F	128.9%	0.1%	129.0%	0.1%

Note: (a) These ratios affected by working capital approach only.
(b) These ratios affected by debt financing approach only.
Source: ERG estimates.

to 3 percent decline in working capital, depending on the assumed level of development. All other ratios change by no more than 0.2 percent for this regulatory package.

The more expensive regulatory packages have the potential to substantially impact the working capital for a typical independent oil company. It must be questioned, however, whether a typical independent would choose to fund <u>all</u> of these expenditures out of working capital or whether some mix of working capital and debt would be used.

SECTION NINE

IMPACTS ON PRODUCTION

The incremental costs of additional pollution control potentially can lead to a loss in production due to early closure of projects or to projects not being undertaken. This section presents the methodology used to evaluate the potential loss in production under the different regulatory options.

9.1 METHODOLOGY

The basic approach is to use the change in the present value of production due to incremental pollution control costs to estimate the potential loss in production. We begin by estimating "baseline" production[1] -- that is, the present value of production from all projects before any incremental costs. To obtain baseline production, production by project is calculated by multiplying the present value of production for a particular project by the number of such projects. This number is aggregated over all projects to provide total estimated production.

Production is then recalculated using the present value of production under the different regulatory options. Production is set to zero if a project begins with a positive net present value but has a negative net present value under a regulatory option. Under these circumstances, the project would either not be undertaken (NSPS) or would close rather than make the additional investment (BAT). The recalculated production estimate, then, takes into consideration early curtailment of projects, immediate project shutdown (BAT), or projects not undertaken (NSPS).

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[1]Production is expressed in terms of BOE (barrels-of-oil equivalent) in order to compare both oil and gas production on a common basis. The conversion factor is based on the heating value of the product. A barrel of oil is 5.8 million BTU and an MMCF of gas is 1,021 million BTU. An MMCF of gas is equivalent to 176.03 BOE.

9.2 DRILLING FLUIDS AND DRILL CUTTINGS

No change is seen in the present value of production under any of the options for drilling fluids and drill cuttings. Nor do the impacts appear so severe that projects would not be undertaken. Minimal impacts on production are estimated for this set of effluent guidelines.

9.3 PRODUCED WATER - BAT

For existing structures, ERG began by comparing the oil and gas production in barrels-of-oil equivalent (BOE) as estimated by the BAT model projects with the actual production in 1986. Table 9-1 lists the number of each type of structure and its associated mid-life production before any additional costs of pollution control. The approximately 557 million barrels of oil and 3 tcf of gas are equivalent to approximately 1.09 billion BOE. Offshore production in 1988 was approximately 321 million barrels and 4.3 tcf, or approximately 1.08 billion BOE (MMS 1989). The estimated amount of energy produced is within 1 percent of actual production.

Table 9-2 shows the potential loss of production under the various regulatory options. The Zero Discharge option leads to about a 4.1 percent and a 4.9 percent decrease in production with membrane and granular filter costs, respectively. The All Filter option has an associated loss of 1.1 to 1.8 percent. The 4-Mile Filter; BPT Other option has an associated potential loss ranging from 0.0 to 0.1 percent.

9.4 PRODUCED WATER - NSPS

Table 9-3 shows the potential loss in production from incremental pollution controls on produced water for new projects.

Under the most reasonable estimate (the $21/bbl - restricted scenario - membrane filter costs) the impacts on production range from a 0.0 percent loss under the 4-Mile Filter; BPT Other option to a 0.2 percent loss under the Zero Discharge and All Filter options. In fact the only situation where a potential loss in production exceeds 0.2 percent is when injection is required, restricted development is assumed, and the price of oil averages $15/bbl during the 1986-2000 time period. The Zero Discharge option, $15/bbl oil price scenario, results in a large loss in production because the net present value for the Gulf 24 gas-only projects turns negative with the additional costs. That is, all Gulf 24 bat_prd.wk1

TABLE 9-1

ESTIMATED 1988 PRODUCTION FROM BAT STRUCTURES

Project	Number Of Structures	Per-Project Production Oil (bbl)	Per-Project Production Gas (MMCF)	Production Oil (bbl)	Production Gas (MMCF)	Regional Barrels-of-oil Equivalent (BOE)	
Oil - only							
Gulf 1a	64	75,008		4,800,480			
Gulf 1b	10	54,020		540,200			
Gulf 4	41	198,998		8,158,918			
Gulf 6	18	298,278		5,369,004			
Gulf 12	22	626,340		13,779,480			
Gulf 24	5	948,051		4,740,255			
Gulf 40	1	1,572,128		1,572,128			
Gulf 50	0						
Oil and Gas							
Gulf 1a	220	68,985	115	15,176,700	25,300		
Gulf 1b	95	49,640	83	4,715,800	7,885		
Gulf 4	111	183,960	307	20,419,560	34,077		
Gulf 6	126	275,940	460	34,768,440	57,960		
Gulf 12	218	579,620	967	126,357,160	210,806		
Gulf 24	196	876,438	1,465	171,781,848	287,140		
Gulf 40	2	1,454,160	2,429	2,908,320	4,858		
Gulf 50	0						
Pacific 16	8	1,727,180	920	13,817,440	7,360		
Pacific 40	6	4,121,799	2,192	24,730,794	13,152		
Pacific 70	12	8,628,600	4,577	103,543,200	54,924		
Gas-only							
Gulf 1a	390		766		298,740		
Gulf 1b	250		548		137,000		
Gulf 4	164		2,044		335,216		
Gulf 6	157		2,847		446,979		
Gulf 12	104		6,570		683,280		
Gulf 24	39		9,855		384,345		
Pacific 16	1		16,863		16,863		
Gulf Production				415,088,293	2,989,022	941,259,235	87%
Pacific Production				142,091,434	16,863	145,059,903	13%
TOTAL PRODUCTION				557,179,727	3,005,885	1,086,319,138	

Source: ERG estimates.

TABLE 9-2

POTENTIAL LOSS OF PRODUCTION (MILLIONS OF BOE)
(1986-2000 TIME FRAME)
BAT PRODUCED WATER

Scenario		Total PV of Production (Millions of BOE)	Potential Loss in Production (Millions of BOE)	
			Data	Percent
Baseline		3,946		
Zero Discharge	Granular Filter Costs	3,754	192	-4.9%
	Membrane Filter Costs	3,786	160	-4.1%
All Filter	Granular Filter Costs	3,876	70	-1.8%
	Membrane Filter Costs	3,904	42	-1.1%
4-Mile Filter; BPT Deep	Granular Filter Costs	3,943	3	-0.1%
	Membrane Filter Costs	3,945	2	-0.0%

Source: ERG estimates.

TABLE 9-3

POTENTIAL LOSS OF PRODUCTION (MILLIONS OF BOE)
(1986-2000 TIME FRAME)
NSPS PRODUCED WATER

Option	Scenario	Total PV of Production (Millions of BOE)	Potential Loss in Production (Millions of BOE)	
			Data	Percent
Baseline	$21/bbl - Restricted	7,776		
	$21/bbl - Restricted (membrane)	7,776		
	$21/bbl - Unrestricted	9,376		
	$21/bbl - Unrestricted (membrane)	9,376		
	$15/bbl - Restricted	6,638		
	$32/bbl - Unrestricted	12,109		
Zero Discharge	$21/bbl - Restricted	7,759	17	-0.2%
	$21/bbl - Restricted (membrane)	7,759	17	-0.2%
	$21/bbl - Unrestricted	9,359	17	-0.2%
	$21/bbl - Unrestricted (membrane)	9,359	17	-0.2%
	$15/bbl - Restricted	5,632	1006	-15.2%
	$32/bbl - Unrestricted	12,105	4	-0.0%
All Filter	$21/bbl - Restricted	7,759	17	-0.2%
	$21/bbl - Restricted (membrane)	7,773	3	-0.0%
	$21/bbl - Unrestricted	9,359	17	-0.2%
	$21/bbl - Unrestricted (membrane)	9,373	3	-0.0%
	$15/bbl - Restricted	6,635	2.9	-0.0%
	$32/bbl - Unrestricted	12,106	3.8	-0.0%
4-Mile Filter; BPT Deep	$21/bbl - Restricted	7,775	0.7	-0.0%
	$21/bbl - Restricted (membrane)	7,775	0.7	-0.0%
	$21/bbl - Unrestricted	9,375	0.7	-0.0%
	$21/bbl - Unrestricted (membrane)	9,375	0.7	-0.0%
	$15/bbl - Restricted	6,637	0.7	-0.0%
	$32/bbl - Unrestricted	12,109	0.5	-0.0%

Note: All scenarios assume granular filter costs except those which state "(membrane)".

Source: ERG estimates.

gas-only projects are assumed not to be undertaken under these circumstances.

9.5 COMBINED EFFECTS OF SELECTED REGULATORY OPTIONS

Six combinations of options were selected for investigation. These regulatory packages are:

- Drilling Fluids and Drill Cuttings: 4-Mile Barge; 1,1 Other[2]
  Produced Water - BAT: 4-Mile Filter; BPT Other (granular filter costs)
  Produced Water - NSPS: 4-Mile Filter; BPT Other (granular filter costs)

- Drilling Fluids and Drill Cuttings: 4-Mile Barge; 1,1 Other[1]
  Produced Water - BAT: Zero Discharge (granular filter costs)
  Produced Water - NSPS: Zero Discharge (granular filter costs)

- Drilling Fluids and Drill Cuttings: 4-Mile Barge; 1,1 Other[1]
  Produced Water - BAT: All Filter (granular filter costs)
  Produced Water - NSPS: All Filter (granular filter costs)

- Drilling Fluids and Drill Cuttings: 4-Mile Barge; 1,1 Other[1]
  Produced Water - BAT: All Filter (membrane filter costs)
  Produced Water - NSPS: All Filter (membrane filter costs)

- Drilling Fluids and Drill Cuttings: 4-Mile Barge; 1,1 Other[1]
  Produced Water - BAT: BPT All
  Produced Water - NSPS: BPT All

- Drilling Fluids and Drill Cuttings: 4-Mile Barge; 1,1 Other[1]
  Produced Water - BAT: 4-Mile Filter; BPT Other (membrane filter costs)
  Produced Water - NSPS: 4-Mile Filter; BPT Other (membrane filter costs)

They are referred to as regulatory packages A through F, respectively.

Table 9-4 summarizes the combined impacts on production for the $21/bbl restricted scenario. The potential loss in production under regulatory package

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[2]Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

TABLE 9-4

POTENTIAL LOSS OF PRODUCTION (MILLIONS OF BOE)
1986-2000 TIME PERIOD
IMPACTS OF COMBINED REGULATORY PACKAGES

$21/bbl - RESTRICTED ACTIVITY

Regulatory Package	Effluent	Effluent Control Option	Total PV of Production	Potential Loss in Production	
				Data	Percent Change
	Baseline		11,722		
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	11,719	4	-0.0%
	Produced Water - BAT	4-Mile Filter; BPT Other			
	Produced Water - NSPS	4-Mile Filter; BPT Other			
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	11,513	209	-1.8%
	Produced Water - BAT	Zero Discharge			
	Produced Water - NSPS	Zero Discharge			
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	11,636	87	-0.7%
	Produced Water - BAT	All Filter			
	Produced Water - NSPS	All Filter			
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	11,677	45	-0.4%
	Produced Water - BAT	All Filter - Membrane			
	Produced Water - NSPS	All Filter - Membrane			
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	11,722	0	0.0%
	Produced Water - BAT	BPT All			
	Produced Water - NSPS	BPT All			
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	11,720	2	-0.0%
	Produced Water - BAT	4-Mile Filter; BPT Other - Membrane			
	Produced Water - NSPS	4-Mile Filter; BPT Other - Membrane			

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement, but must comply with the 1,1 All restrictions.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology.

Source: ERG estimates.

F is negligible: less than one-tenth of one percent of total production.

Table 9-5 summarizes the same information for the $21/bbl unrestricted scenario. The potential loss in production under regulatory package F is negligible: less than one-tenth of one percent of total production.

9.6 REFERENCES

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TABLE 9-5

POTENTIAL LOSS OF PRODUCTION (MILLIONS OF BOE)
1986-2000 TIME PERIOD
IMPACTS OF COMBINED REGULATORY PACKAGES

$21/bbl - UNRESTRICTED ACTIVITY

Regulatory Package	Effluent	Effluent Control Option	Total PV of Production	Potential Loss in Production: Data	Potential Loss in Production: Percent Change
	Baseline		13,322		
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	13,319	4	-0.0%
	Produced Water - BAT	4-Mile Filter; BPT Other			
	Produced Water - NSPS	4-Mile Filter; BPT Other			
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	13,113	209	-1.6%
	Produced Water - BAT	Zero Discharge			
	Produced Water - NSPS	Zero Discharge			
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	13,235	87	-0.7%
	Produced Water - BAT	All Filter			
	Produced Water - NSPS	All Filter			
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	13,277	45	-0.3%
	Produced Water - BAT	All Filter - Membrane			
	Produced Water - NSPS	All Filter - Membrane			
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	13,322	0	0.0%
	Produced Water - BAT	BPT All			
	Produced Water - NSPS	BPT All			
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	13,320	2	-0.0%
	Produced Water - BAT	4-Mile Filter; BPT Other - Membrane			
	Produced Water - NSPS	4-Mile Filter; BPT Other - Membrane			

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement, but must comply with the 1,1 All restrictions.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology.

Source: ERG estimates.

SECTION TEN

SECONDARY IMPACTS OF BAT AND NSPS REGULATIONS

Although the costs and economic impacts of BAT and NSPS regulations would fall primarily on the major and independent oil companies, secondary effects in other sectors of the economy would also occur. In this section, ERG reviews the potential effects of regulatory costs on Federal revenues, State revenues, the balance of trade, and support industries. The average annual cost of the regulations is developed in Section Six.

The impacts are investigated for six packages of regulatory options:

▪ Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other[1]
Produced Water - BAT	4-Mile Filter; BPT Other
Produced Water - NPS	4-Mile Filter; BPT Other
▪ Drilling Fluids and Drill Cuttings	4-Mile Barge; 1,1 Other[1]
Produced Water - BAT	Zero Discharge
Produced Water - NSPS	Zero Discharge
▪ Drilling Fluids and Drill Cuttings	4-Mile Barge; 1,1 Other[1]
Produced Water - BAT	All Filter
Produced Water - NSPS	All Filter
▪ Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other[1]
Produced Water - BAT	All Filter - Membrane
Produced Water - NSPS	All Filter - Membrane
▪ Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other[1]
Produced Water - BAT	BPT All
Produced Water - NSPS	BPT All
▪ Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other[1]
Produced Water - BAT	4-Mile Filter; BPT Other - Membrane
Produced Water - NSPS	4-Mile Filter; BPT Other - Membrane

They are referred to as regulatory packages A through F, respectively.

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[1]Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

10.1 IMPACTS ON FEDERAL REVENUES

Offshore oil and gas activity generates revenue for the Federal government from sources such as income taxes paid by developers, leasing payments, and royalties. All of these revenue sources could be affected by effluent guidelines limitations costs.

It is assumed that companies involved in offshore oil and gas production have over $100,000 of net income annually, and that their marginal tax rate is therefore 34 percent. Thus, any expenditure or depreciation item generates a tax savings of 34 percent of its face value. The Federal government, therefore, loses 34 percent of the cost of compliance through tax savings to the company.

Developers could possibly reduce the impact of the "remaining regulatory costs" (i.e., 66 percent of all costs) by reducing their lease bonus bids. Since the costs of effluent guidelines limitations and standards can reduce the return on offshore oil and gas projects, it is logical that operators would pay less for the right to explore offshore areas. Under the $21/bbl scenario with restricted activity, an estimated 91 percent of projected development is allocated to Federal waters (see Table 10-1); therefore, ERG assumes 91 percent of the remaining costs could be recouped by the company through lower lease bids on Federal areas.

Table 10-2 lists these potential impacts on Federal revenues. For example, under regulatory package F (4-Mile Barge; 1,1 Other for drilling wastes and 4-Mile Filter; BPT Other for produced water) the total annual cost of the regulation is $54 million (1986 dollars). Revenue lost to the Federal government through tax savings is $54 x .34 or $18 million. Losses from tax savings range from $10 million to $367 million under the various regulatory packages.

There may also be a potential loss of Federal revenue through lower lease bids. This loss is equal to 91 percent of the remaining cost. For example, under regulatory package F the potential loss due to lower lease bids equals ($54 minus $18) x .91 or $32 million. Companies may or may not choose to reduce their bonus bids by the full amount available. Hence, entries in this column are labeled "potential" losses. The potential losses shown in Table 10-2 are the maximum bid reductions that recoup all cost increases remaining after the tax savings. The potential losses range from $18 to $649 million

TABLE 10-1

RATIO OF FEDERAL-TO-STATE PRODUCTION
PROJECTED PRODUCTIVE DEVELOPMENT WELLS IN OFFSHORE REGION (1986-2000)

$21/bbl - RESTRICTED ACTIVITY

Region	Number of State Wells	Number of Federal Wells	Total Number of Productive Wells
Gulf	538	5,915	6,453
Pacific	0	382	382
Atlantic	0	0	0
Alaska	69	29	98
Total	607	6,326	6,933
Percent of Total	8.8%	91.2%	

Note: These counts compare with Table 4-7b for the Gulf and Alaska regions and with Table 4-16 for the Pacific region.
No activity is assumed for the Atlantic.

TABLE 10-2

POTENTIAL LOSS OF FEDERAL REVENUES ($MILLIONS, 1986 DOLLARS)
IMPACTS OF COMBINED REGULATORY PACKAGES

$21/bbl - RESTRICTED ACTIVITY

Regulatory Package	Effluent	Effluent Control Option	Total Annual Cost	Revenue Loss Due to Tax Effects of Effluent Guidelines	Potential Revenue Loss Due to Lower Lease Bids	Total Potential Revenue Loss to Federal Government
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$88	$30	$53	$82
	Produced Water - BAT	4-Mile Filter; BPT Other				
	Produced Water - NSPS	4-Mile Filter; BPT Other				
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$1,081	$367	$649	$1,017
	Produced Water - BAT	Zero Discharge				
	Produced Water - NSPS	Zero Discharge				
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$605	$206	$363	$569
	Produced Water - BAT	All Filter				
	Produced Water - NSPS	All Filter				
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$242	$82	$145	$228
	Produced Water - BAT	All Filter - Membrane				
	Produced Water - NSPS	All Filter - Membrane				
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$10	$18	$28
	Produced Water - BAT	BPT All				
	Produced Water - NSPS	BPT All				
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$54	$18	$32	$50
	Produced Water - BAT	4-Mile Filter; BPT Other -Mem				
	Produced Water - NSPS	4-Mile Filter; BPT Other -Mem				

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology.

Source: ERG estimates.

dollars. The total potential revenue loss to the Federal government ranges from $28 million to $1,017 million.

Table 10-3 lists the results of recent OCS sales. In 1986, only $187 million was received in bonuses in two lease sales in the Gulf. This was the lowest level of bonus receipts for several years. Interest picked up again in 1987, when two lease sales in the Gulf brought in $535 million in apparent high bids. In 1988, OCS sales brought in $1,209 million in bonuses. The potential loss in Federal revenues due to lower lease bids and tax savings to the companies (from Table 10-2) ranges from 2 to 84 percent of the 1988 bonuses. These losses, however, are only potential losses; that is, companies may choose not to recoup all cost increases through lower bonus bids.

The third source of potential loss is the loss of royalties due to early closure of projects or projects not undertaken. This source would be reflected as a loss of royalties due to a potential loss in future production. Section Nine investigates potential loss of future production. Assuming $21/bbl and restricted development, the potential loss in production from regulatory package F is negligible. Similarly, impacts on royalties would be expected to be negligible.

10.2 IMPACTS ON STATE REVENUES

Industry could reduce the impacts of the cost of compliance with new regulations by reducing lease bonus bids on State tracts. The well projections estimate that 9 percent of future offshore activity will take place in State waters (see Table 10-1). Potential loss in revenue for the states is calculated as the cost of the regulatory package times the percentage borne by the industry (i.e., not including the 34 percent tax savings) times the portion of development that takes place in State waters. Under regulatory package F, the calculation is $54 x .66 x .09 or $3 million (1986 dollars). Table 10-4 summarizes these costs, which range from $2 to $64 million.

These losses are only potential; companies may not choose to recoup all cost increases through lower lease bids. In addition, the potential losses, should they occur, would be spread among several states. New wells are projected for Alaska, the Pacific, and the Gulf of Mexico. Under the $21/bbl restricted development scenario, the only drilling that occurs in California State waters is on existing leases. California, then, would not suffer any

TABLE 10-3

RECENT OCS LEASE SALES

Sale	Date	Region	Bonuses Accepted ($Million)*	Annual Total ($Million)*
104	April 1986	Central Gulf of Mexico	$130.3	
105	August 1986	Western Gulf of Mexico	$56.8	$187.1
110	April 1987	Central Gulf of Mexico	$292.6	
112	August 1987	Western Gulf of Mexico	$242.8	$535.4
97	March 1988	Beaufort Sea, Alaska	$114.6	
113	March 1988	Central Gulf of Mexico	$388.7	
109	May 1988	Chukchi Sea, Alaska	$478.0	
115	August 1988	Western Gulf of Mexico	$125.4	
92	October 1988	N. Aleutian, Alaska	$95.4	
116	November 1988	Eastern Gulf of Mexico	$6.4	$1,208.5

* Current dollars.
Source: MMS, 1989.

TABLE 10-4

POTENTIAL IMPACT OF COMPLIANCE COSTS ON STATE REVENUES
$MILLIONS, 1986 DOLLARS

$21/bbl - RESTRICTED ACTIVITY

Regulatory Package	Effluent	Effluent Control Option	Total Annual Cost	Potential Revenue Loss Due to Lower Lease Bids
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$88	$5
	Produced Water - BAT	4-Mile Filter; BPT Other		
	Produced Water - NSPS	4-Mile Filter; BPT Other		
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$1,081	$64
	Produced Water - BAT	Zero Discharge		
	Produced Water - NSPS	Zero Discharge		
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$605	$36
	Produced Water - BAT	All Filter		
	Produced Water - NSPS	All Filter		
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$242	$14
	Produced Water - BAT	All Filter - Membrane		
	Produced Water - NSPS	All Filter - Membrane		
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$30	$2
	Produced Water - BAT	BPT All		
	Produced Water - NSPS	BPT All		
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other*	$54	$3
	Produced Water - BAT	4-Mile Filter; BPT Other -Membrane		
	Produced Water - NSPS	4-Mile Filter; BPT Other -Membrane		

* Under the 4-Mile Barge; 1,1 Other option, Alaska is exempt from the barging requirement but must comply with the 1,1 All restrictions.

Notes: All produced water control options assume the use of granular filter technology except options D & F, which assume the use of membrane filtration technology. Entries may not sum due to independent rounding.

Source: ERG estimates.

loss of bonus revenue due to increased pollution controls. Affected states could include Alaska, Texas, Louisiana, Mississippi and Alabama.

The example of Texas illustrates the potential impacts on State income. In 1985, Texas produced 2,175,630 bbl of oil and 108,130,195 Mcf of gas from offshore State wells. In the same year, the other major producing state in the Gulf of Mexico, Louisiana, produced 23,747,805 bbls of oil and 229,971,735 Mcf of gas from offshore State wells (MMS, 1986). These figures convert to 21,210,361 barrels-of-oil equivalent (BOE) for Texas and 64,230,760 BOE for Louisiana. Texas therefore generated 25 percent of State offshore production in the Gulf of Mexico in 1985, while Louisiana produced the remaining 75 percent.

Table 10-5 shows the calculation to estimate the potential revenue loss through lower bonus bids. The estimated loss is the product of four factors:

- Proportion of cost not shielded by tax savings on expensed and depreciated items.
- Portion of project occurring in State waters.
- Portion of State water activity occurring in the Gulf of Mexico.
- Portion of Gulf of Mexico State water activity occurring in Texas.

The last parameter is the proportion of 1985 Gulf of Mexico State water production occurring in Texas State waters. The potential loss ranges from $0.4 to $14.2 million (1986 dollars).

Table 10-6 presents total income to Texas from oil and gas bonuses and from all sources for 1984 through 1989. Texas received $25 million in lease bonus revenues in 1986 and more in 1988. Potential losses range from 2 to 56 percent of 1986 bonuses. Total State revenues for 1986 are $17,952 million; compared to total State revenues, the impact of the most expensive regulatory package is less than 0.01 percent.

Tables 10-7 and 10-8 repeat the calculations for Louisiana, whose fiscal year runs from 1 July to 30 June. The potential loss in revenue ranges from $1.2 to $42.7 million. Louisiana's income from bonuses fell from $60 million in fiscal year 1984-1985 to $26.0 million in 1985-1986 to $12 million in 1986-1987, due, in part, to the crash in oil prices. The data from the most recent two years indicate how this sector of the economy has begun to recover.

TABLE 10-5

POTENTIAL IMPACT OF COMPLIANCE COSTS ON TEXAS STATE REVENUES
$MILLIONS, 1986 DOLLARS

$21/bbl -RESTRICTED

Regulatory Package	Effluent	Effluent Control Option	Total Annual Cost	Proportion of Cost Not Shielded by Federal Tax Savings	Portion of Projected Development in State Waters	Portion of State Water Development in Gulf of Mexico	Portion of GOM State Water Development in Texas Water	Potential Revenue Loss Due to Lower Lease Bids
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$88	0.66	0.09	0.89	0.25	$1.2
	Produced Water - BAT	4-Mile Filter; BPT Other						
	Produced Water - NSPS	4-Mile Filter; BPT Other						
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$1,081	0.66	0.09	0.89	0.25	$14.2
	Produced Water - BAT	Zero Discharge						
	Produced Water - NSPS	Zero Discharge						
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$605	0.66	0.09	0.89	0.25	$8.0
	Produced Water - BAT	All Filter						
	Produced Water - NSPS	All Filter						
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$242	0.66	0.09	0.89	0.25	$3.2
	Produced Water - BAT	All Filter - Membrane						
	Produced Water - NSPS	All Filter - Membrane						
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$30	0.66	0.09	0.89	0.25	$0.4
	Produced Water - BAT	BPT All						
	Produced Water - NSPS	BPT All						
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$54	0.66	0.09	0.89	0.25	$0.7
	Produced Water - BAT	4-Mile Filter; BPT Other -Mem						
	Produced Water - NSPS	4-Mile Filter; BPT Other -Mem						

Note: Entries may not sum due to independent rounding.
Source: ERG estimates.

TABLE 10-6

TOTAL TEXAS STATE REVENUES AND BONUS REVENUES

Year	Bonus Revenues* ($Million)	Total State Revenues* ($Million)
1985	$60.3	$16,980
1986	$25.4	$17,952
1987	$18.4	$17,524
1988	$26.0	$20,357
1989	$24.3	$21,479

* Current dollars.

Source: Plaut, 1990.

TABLE 10-7

POTENTIAL IMPACT OF COMPLIANCE COSTS ON LOUISIANA STATE REVENUES
$MILLIONS, 1986 DOLLARS

$21/bbl -RESTRICTED

Regulatory Package	Effluent	Effluent Control Option	Total Annual Cost	Proportion of Cost Not Shielded by Federal Tax Savings	Portion of Projected Development in State Waters	Portion of State Water Development in Gulf of Mexico	Portion of GOM State Water Development in Louisiana Water	Potential Revenue Loss Due to Lower Lease Bids
A	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$88	0.66	0.09	0.89	0.75	$3.5
	Produced Water - BAT	4-Mile Filter; BPT Other						
	Produced Water - NSPS	4-Mile Filter; BPT Other						
B	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$1,081	0.66	0.09	0.89	0.75	$42.7
	Produced Water - BAT	Zero Discharge						
	Produced Water - NSPS	Zero Discharge						
C	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$605	0.66	0.09	0.89	0.75	$23.9
	Produced Water - BAT	All Filter						
	Produced Water - NSPS	All Filter						
D	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$242	0.66	0.09	0.89	0.75	$9.6
	Produced Water - BAT	All Filter - Membrane						
	Produced Water - NSPS	All Filter - Membrane						
E	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$30	0.66	0.09	0.89	0.75	$1.2
	Produced Water - BAT	BPT All						
	Produced Water - NSPS	BPT All						
F	Drilling Fluid and Drill Cuttings	4-Mile Barge; 1,1 Other	$54	0.66	0.09	0.89	0.75	$2.1
	Produced Water - BAT	4-Mile Filter; BPT Other -Mem						
	Produced Water - NSPS	4-Mile Filter; BPT Other -Mem						

Note: Entries may not sum due to independent rounding.
Source: ERG estimates.

TABLE 10-8

TOTAL LOUISIANA STATE REVENUES AND BONUS REVENUES

Year	Bonus Revenues* ($Million)	Total State Revenues* ($Million)
1984-1985	$59.7	$8,804
1985-1986	$26.0	$8,800
1986-1987	$12.1	$9,306
1987-1988	$27.7	$9,105
1988-1989	$14.7	$10,186

* Current dollars.

Source: Hoppenstedt, 1990.

Bonuses were $28 million in 1987-1988 and $15 million in 1988-1989. For some of the regulatory packages, the potential loss in revenues exceeds actual bonus revenues for some years. For package F, the potential revenue loss represents about 17 percent of bonus revenues for 1986-1987 (the lowest bonus revenue of the series). The impact of the most expensive regulatory package (package B) on total State revenue for 1985-1986 (the lowest total revenue in the series), however, is still less than 0.5 percent.

The second source of potential loss is the loss of royalties and severance taxes due to early closure of projects or projects not undertaken. This source would be reflected as a loss of royalties due to a potential loss in future production. Section Nine investigates the potential loss of future production. The potential loss in production from regulatory package F is negligible; thus, impacts on royalties would be expected to be negligible as well.

10.3 IMPACT ON BALANCE OF TRADE

The United States is rapidly approaching the time when we are a nation that imports more oil than it produces. The Department of Energy projects this time to arrive in 1994 (DOE, 1989), but is already happening sporadically on a monthly basis. For example, in January 1990, the United States imported 54 percent of our domestic demand for oil and gas (OGJ, 1990a). The recent increase in oil prices due to the Mideast crisis is also not expected to prevent a decline in domestic oil production. A shortage of trained personnel and workover rigs are factors cited as limiting any near-term sizable increase in domestic production (OGJ, 1990b; OGJ, 1990c; and OGJ, 1990d). In other words, unless domestic demand for oil is curbed, the United States will continue to import a growing percentage of its domestic oil consumption. This phenomenon is occurring in absence of any incremental pollution control costs.

The potential loss in production is investigated in Section Nine. Even under regulatory package B with the highest projected costs, production declines over the entire 15-year period do not exceed 1.8 percent. This is a small percentage compared to the estimated <u>annual</u> decline in domestic production of about 3 percent seen in the DOE projections (DOE, 1989). In other words, the change in the balance of trade expected from this regulatory effort will not be significant compared to changes caused by outside factors.

10.4 IMPACTS ON SERVICE INDUSTRIES

In addition to major and independent oil companies, a third group of companies provides a variety of specialized services to the offshore oil and gas developers. These firms construct, own, and operate mobile drilling rigs; fabricate and install offshore platforms; provide geophysical, drilling mud, and well logging services; build and install pipelines to transport oil and gas from platforms to onshore terminals; and own and operate boat and helicopter fleets that provide support services to offshore drilling rigs and platforms.

Regulatory costs can be incurred through increased barite costs, barging of spent drilling fluids and cuttings, or capital and annual operating costs required for the disposal of produced water. Drilling fluid suppliers are assumed to operate in a competitive market and will, therefore, pass on any cost increases that occur with the use of "clean" barite. Since the well operators are the ones who purchase the drilling fluid and disposal equipment, they will ultimately bear the cost. The Agency also assumes that whatever cost is incurred in the barging of drilling wastes is paid for by the operators.

All costs, then, are assumed to be passed through to the operator. Under these conditions, no negative impacts are incurred by the service industries. Sections Seven and Eight examine the impacts on individual projects and representative companies, respectively. In addition, when the regulations become effective, activity for the service industry will increase due to the need to retrofit existing facilities. In this respect, the regulations could lead to a temporary positive impact on the service industry.

10.5 IMPACTS ON INFLATION

The regulations can lead to higher costs to the operators. When evaluating this effect on typical companies, ERG did not assume that they could raise prices to recover these costs. This is because the price that the companies will receive for their product is determined by the world oil price and not domestic costs. Given our nation's continued growth in demand, supply (and therefore price) is still largely controlled by the behavior of the OPEC members (see DOE, 1989 and Harvard, 1988). Because of the inability of the companies to raise prices in response to increased costs, we do not see substantial impacts on inflation from increased cost of pollution controls on offshore oil and gas effluents. We investigated the impacts on the companies (Section Eight) and the impacts on production (Section Nine) under this set of assumptions.

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SECTION ELEVEN

SINGLE WELL STRUCTURES IN THE GULF OF MEXICO

The smallest project examined in the analysis is a structure with a single well. ERG developed two economic models for single well structures -- those which do not have production equipment and those which do. The models are called "Gulf 1a" and "Gulf 1b," respectively. (Single well structures currently exist only in the offshore Gulf of Mexico.) Gulf 1a structures are assumed to share production equipment and increased pollution control costs with three other structures. Gulf 1b structures are assumed not to be able to share costs. For example, each Gulf 1b structure is assumed to bear the entire cost of an injection well under the Zero Discharge option.

Because of its small size, the Gulf 1b is the most vulnerable of economic models to the impacts of additional pollution control costs. It is the only project for which the net present value (NPV) has the potential to change from positive in the baseline case to negative when incremental costs of additional pollution controls on produced water are added (see Section Seven).[1] This change is modeled as a complete shut-down of the project for the analysis of the impacts on production (see Section Nine). That is, existing projects are assumed to shut down rather than undertake the capital investments of added pollution control, and new projects are considered not to go into production. The change in the sign of the NPV, however, occurs only for the Gulf 1b (a single well structure with its own production equipment) and only in limited circumstances.

Examining Tables 7-9 and 7-16, the Gulf 1b shuts down in the following cases:

- BAT
    - Zero Discharge
        - Offshore, both granular and membrane costs
        - Onshore, granular costs

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[1]Even under the Zero Discharge option for drilling fluids and drill cuttings, the net present value of the Gulf 1b project remains positive. The discussion, then, focuses on pollution controls for produced water.

- NSPS
  - Zero Discharge
    - Offshore, both granular and membrane costs
    - Onshore, granular costs
  - Filtration
    - Granular filter costs only

In other words, no shutdowns are projected under the 4-Mile Filter; BPT Other option for BAT structures, regardless of the costing assumptions. For NSPS structures, shutdowns are projected only under the higher costs associated with granular filter technology. No shutdowns are projected under membrane cost assumptions. Projects may still be undertaken but may have a shorter economic lifetime due to increased annual operating costs. Potential losses from projects with curtailed lifetimes are examined in Section Nine and are minimal for the 4-Mile Filter; BPT Other option.

Even though the Gulf 1b structures undergo closure or are not undertaken only in a limited set of circumstances, and these circumstances are not the preferred option in the rulemaking, this section examines the:

- Number of Gulf 1b structures.
- Estimated production from Gulf 1b structures.
- Relative contribution from Gulf 1b structures to total production from Federal offshore leases and to total U.S. production (onshore and offshore).

We also examined the ownership of the existing structures as it appears in the March 1988 version of the MMS Platform Inspection System, Complex/ Structure data base.

The purpose of the examination is to evaluate the potential loss of production from these structures. An exemption for such structures would not be made to encourage the proliferation of single-well structures for the sole purpose of avoiding additional pollution control costs. The purpose of the exemption would be to allow the economic recovery of oil and gas from small fields that can adequately be drained by a single well. For example, if information for a particular field indicates that the reserves are greater than originally thought, and that a second well could be added to drain the reservoir, the first well could be required to tie into the pollution control equipment of the second well for the field since the field was no longer in the "single well size" category.

11.1 BAT STRUCTURES

The number of structures in production in the Gulf of Mexico is taken from the MMS Platform Inspection System, Complex/Structure data base as of March 1988. Table 11-1 summarizes this information. Appendix H describes the data cleaning and categorization processes used to develop these counts from the MMS data base. There were approximately 2,233 structures in production in the Gulf, of which 355 or about 16 percent were classified as Gulf 1b structures. The estimated production in the Gulf is approximately 415 million barrels of oil and 3 tcf of gas (see Table 11-2). Production from Gulf 1b structures is estimated to be approximately 5.3 million barrels of oil and 145 bcf of gas.

Table 11-3 compares the production from all Gulf 1b structures with the estimated production in the Gulf, the actual 1988 production from Federal offshore leases, and the total 1988 U.S. production (both onshore and offshore). Production from Gulf 1b structures corresponds to 1.3 and 4.8 percent of the estimated oil and gas production for the Gulf, respectively. The Gulf of Mexico produces nearly all the gas and most of the oil from Federal offshore leases (see Table 11-2 and MMS 1989). Estimated production from Gulf 1b structures is approximately 2 and 3 percent of actual 1988 production from Federal offshore leases. Total 1988 U.S. production was 3 billion barrels of crude oil (API 1990, Section IV, Table 3a) and 17.8 tcf of gas (DOE 1989, Table 3). Production from Gulf 1b structures is less than 1 percent of total U.S. production.

About 25 percent of the Gulf 1b structures are connected to another structure by at least a catwalk.[2] Our assumption that these structures would serve only "one well" fields is therefore conservative. The MMS Complex/Structure data base also contains the operator of the structure. The <u>1988 U.S.A. Oil Industry Directory</u> was used to identify major and independent oil companies (PennWell 1988). Combining the information from these two sources, ERG identified about two-thirds of these structures as having major oil

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[2]In the MMS data base, a complex may be made up of one or more structures as long as the structures are connected by some means, e.g., a catwalk. Each complex has a unique identification number given by the MMS. In addition to the complex identification number, each structure in the complex is given a number, beginning with "1". Of the 355 Gulf 1b structures, 89 have structure numbers higher than one. This means that the single well structure is connected to at least one other structure in some manner.

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TABLE 11-1

EXISTING STRUCTURES BY REGION

Structure Type	NUMBER OF STRUCTURES Oil Only <= 4 miles	Oil Only > 4 miles	Oil and Gas <= 4 miles	Oil and Gas > 4 miles	Gas Only <= 4 miles	Gas Only > 4 miles	Total <= 4 miles	Total > 4 miles	Total
Gulf 1a	26	38	27	193	53	337	106	568	674
Gulf 1b	1	9	13	82	22	228	36	319	355
Gulf 4	23	18	10	101	8	156	41	275	316
Gulf 6	0	18	2	124	1	156	3	298	301
Gulf 12	0	22	3	215	0	104	3	341	344
Gulf 24	0	5	8	188	0	39	8	232	240
Gulf 40	0	1	0	2	0	0	0	3	3
Gulf 58	0	0	0	0	0	0	0	0	0
Gulf Totals	50	111	63	905	84	1,020	197	2,036	2,233
Pacific 16	0	0	7	1	0	1	7	2	9
Pacific 40	0	0	0	6	0	0	0	6	6
Pacific 70	0	0	4	8	0	0	4	8	12
Pacific Totals	0	0	11	15	0	1	11	16	27
Atlantic	No existing facilities								
Alaska	No facilities that do not already re-inject produced water								
Totals	50	111	74	920	84	1,021	208	2,052	2,260

Note: Structures in the Gulf of Mexico have been classified according to the number of producing wells. Structures in the Pacific have been classified according to the number of wellslots.

Source: MMS, 1988; CCC, 1988; SAS printout kre_bat6.out; SAS runs dated July 1990.

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TABLE 11-2

ESTIMATED 1988 PRODUCTION FROM BAT STRUCTURES

Project	Number Of Structures	Per-Project Production Oil (bbl)	Per-Project Production Gas (MMCF)	Production Oil (bbl)	Production Gas (MMCF)	Regional Barrels-of-oil Equivalent (BOE)	
Oil - only							
Gulf 1a	64	75,008		4,800,480			
Gulf 1b	10	54,020		540,200			
Gulf 4	41	198,998		8,158,918			
Gulf 6	18	298,278		5,369,004			
Gulf 12	22	626,340		13,779,480			
Gulf 24	5	948,051		4,740,255			
Gulf 40	1	1,572,128		1,572,128			
Gulf 50	0						
Oil and Gas							
Gulf 1a	220	68,985	115	15,176,700	25,300		
Gulf 1b	95	49,640	83	4,715,800	7,885		
Gulf 4	111	183,960	307	20,419,560	34,077		
Gulf 6	126	275,940	460	34,768,440	57,960		
Gulf 12	218	579,620	967	126,357,160	210,806		
Gulf 24	196	876,438	1,465	171,781,848	287,140		
Gulf 40	2	1,454,160	2,429	2,908,320	4,858		
Gulf 50	0						
Pacific 16	8	1,727,180	920	13,817,440	7,360		
Pacific 40	6	4,121,799	2,192	24,730,794	13,152		
Pacific 70	12	8,628,600	4,577	103,543,200	54,924		
Gas-only							
Gulf 1a	390		766		298,740		
Gulf 1b	250		548		137,000		
Gulf 4	164		2,044		335,216		
Gulf 6	157		2,847		446,979		
Gulf 12	104		6,570		683,280		
Gulf 24	39		9,855		384,345		
Pacific 16	1		16,863		16,863		
Gulf Production				415,088,293	2,989,022	941,259,235	87%
Pacific Production				142,091,434	16,863	145,059,903	13%
TOTAL PRODUCTION				557,179,727	3,005,885	1,086,319,138	

Source: ERG estimates.

TABLE 11-3

COMPARISON OF PRODUCTION FROM BAT GULF 1B STRUCTURES TO REGIONAL AND U.S. PRODUCTION

Parameter	Oil (Millions of Barrels)	Gas (Trillions of Cubic Feet)	Percentage	
			Oil	Gas
Estimated Production from all Gulf 1b Structures	5.3	0.145		
Estimated Production from Gulf Structures	415.1	3.0	1.3%	4.8%
1988 Production from Federal Offshore Leases (Actual)	320.7	4.3	1.6%	3.4%
1988 U.S. Onshore and Offshore Production (Actual)	2,979.0	17.8	0.2%	0.8%
Estimated Production from Gulf 1b Structures within 4 miles of Shore	0.7	0.013		
Estimated Production from Gulf Structures	415.1	3.0	0.17%	0.43%
1988 Production from Federal Offshore Leases (Actual)	320.7	4.3	0.22%	0.30%
1988 U.S. Onshore and Offshore Production (Actual)	2,979.0	17.8	0.02%	0.07%

Sources: ERG estimates; MMS, 1989; API, 1990; and DOE, 1989.

companies as operators in March 1988. The majority of the operators, then, are large major oil companies.

One option under consideration is to require that structures within 4 miles of shore filter produced water before discharge. In the data set examined, only 36 Gulf 1b structures are located within 4 miles of shore. Of these, 31 structures are not connected to another structure and are therefore unlikely to be able to share costs. As in the general Gulf 1b population, about two-thirds of the Gulf 1b structures within 4 miles of shore are operated by major oil companies.

The estimated production from this subset of Gulf 1b structures is about 700 thousand barrels of oil and 13 bcf of gas. These amounts represent about 0.2 percent and 0.4 percent of the estimated Gulf oil and gas production, respectively (see Table 11-3, lower half). Compared to actual 1988 production from Federal offshore leases, the estimated production from Gulf 1b structures is 0.2 percent and 0.3 percent for oil and gas, respectively. Estimated production from this subset of Gulf 1b structures accounts for less than 0.1 percent of total U.S. production in 1988.

In other words, assuming that all Gulf 1b structures within 4 miles of shore shut down rather than incur the costs of additional pollution control, the potential production loss is less than 0.5 percent of Federal offshore production. Compared to overall U.S. production, the potential loss from Gulf 1b structures is less than 0.1 percent (0.02 percent loss for oil and 0.07 percent loss for gas). In other words, comparatively little production would be protected by an exemption for single well structures within 4 miles of shore.

Exempting Gulf 1b structures under the 4-Mile Filter; BPT Other option would decrease the cost of that option by $1.7 million, from $12.9 million to $11.2 million dollars; a decrease of 13 percent. These are membrane filter costs. For granular filter costs, exempting Gulf 1b structures under the same option would decrease the cost by $3.2 million, from $41.2 million dollars to $38 million dollars. This is an 8 percent decrease in the cost of the option.

11.2 NSPS STRUCTURES

In the $21/bbl oil price, restricted development scenario, 755 structures are projected for the Gulf of Mexico during the 1986-2000 time period (Table 11-4) including 76 Gulf 1b structures. There are no oil-producing Gulf 1b structures projected within 4 miles of shore.[3] Therefore, an exemption for Gulf 1b structures within 4 miles would show no savings in oil production.

There are 23 Gulf 1b gas-only structures projected within 4 miles of shore. These structures are assumed to have a peak production rate of 4 MMcf/day or 1.46 bcf/year. If all 23 structures went into production in the same year, the first year's production would total 33.6 bcf. This is less than 1 percent of the 1988 gas production Federal offshore leases and less than 0.2 percent of total 1988 U.S. gas production. No more than two structures within 4 miles of shore are assumed to go into production in any year during the 1986-2000 time frame, so impacts are probably an order of magnitude less.

Exempting Gulf 1b structures under the 4-Mile Filter; BPT Other option would decrease the cost of that option by $0.8 million, from $10.7 million to $9.9 million dollars. This is based on membrane filter costs and represents a decrease of 8 percent. Assuming granular filter costs for the same option, exempting Gulf 1b structures would decrease the cost by $1 million, from $16.5 million dollars to $15.5 million dollars. This is a 6 percent decrease in the cost of the option.

11.3 COMBINED EFFECTS

The cost for regulatory package F is $54 million in 1986 dollars. This package combines the 4-Mile Barge; 1,1 Other option for drilling wastes with the 4-Mile Filter; BPT Other option for produced water. The cost of the package is based on membrane filter technology costs. Exempting Gulf 1b structures from pollution control measures beyond current permit requirements for produced water would decrease the cost of the option by about $2.5 million or about 5 percent. No severe adverse impacts were seen for this regulatory

[3]This is not to say that there will be no new single well structures within 4 miles of shore. They are assumed to share production equipment and are included in the projections of 4-well structures for the purposes of estimating impacts.

TABLE 11-4

NSPS STRUCTURE ALLOCATIONS
RESTRICTED ACTIVITY

$21/bbl SCENARIO

		All Platforms			Within 4-Miles			Beyond 4-Miles		
Region	Model	Total	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas
Gulf										
	Gulf 1b	76	12	64	23	0	23	53	12	41
	Gulf 4	235	89	146	60	27	33	175	62	113
	Gulf 6	123	34	89	43	15	28	80	19	61
	Gulf 12	180	84	96	14	14	0	166	70	96
	Gulf 24	114	62	52	0	0	0	114	62	52
	Gulf 40	27	27	0	0	0	0	27	27	0
	Gulf Totals	755	308	447	140	56	84	615	252	363
Pacific										
	Pacific 40	3	3	0	0	0	0	3	3	0
	Pacific 70	4	4	0	0	0	0	4	4	0
	Pacific Totals	7	7	0	0	0	0	7	7	0
Atlantic										
	Atlantic 24	0	0	0	0	0	0	0	0	0
Alaska										
	Cook Inlet 12	1	0	1	0	0	0	1	0	1
	Cook Inlet 24	1	1	0	0	0	0	1	1	0
	B. Gravel Island*	2	2	0	2	2	0	0	0	0
	Alaska Totals	4	3	1	2	2	0	2	1	1
Total Platforms - All Regions		766	318	448	142	58	84	624	260	364

* Oil only; all other projects are assumed to produce oil and casinghead gas.

package in the preceding sections. A 5 percent reduction in total cost would not significantly change impacts already examined. In addition, the effect on production is already minimal for this option (see Section Nine), and exempting the Gulf lb structures would not affect this result.

11.4 REFERENCES

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SECTION TWELVE

SMALL BUSINESS ANALYSIS

Public Law 96-354, known as the Regulatory Flexibility Act, requires EPA to determine if a significant impact on a substantial number of small businesses occurs as a result of proposed regulations. If there is a significant impact, the act requires that alternative regulatory approaches that mitigate or eliminate economic impacts on small businesses be examined.

Various definitions of small businesses are used by Federal agencies in procurement activities and regulatory analysis (47 CFR 121.3). These standards are based on number of employees or sales volume. Employee standards of 100, 200, 250, and 500 have been used. Sales standards of \$100,000, \$1,000,000, \$2,500,000 and \$7,500,000 have also been employed. The Small Business Administration uses a standard of 250 employees for the oil and gas extraction point-source category (SIC 1311).

Production companies would incur the direct regulatory impact of BAT and NSPS. As previously established in Section Three, production companies are generally large corporate or large independent firms. Revenues for a typical independent oil company were \$160 million in 1985 while in 1986, revenues for a typical major are estimated at \$35.3 billion. Large majors and large independents each typically employ well over 500 people. Both these measures indicate that energy production companies are not small businesses. Therefore a formal Regulatory Flexibility Analysis (RFA) is not required.

APPENDIX A

SELECTION OF OFFSHORE OIL AND GAS PROJECTS

Offshore oil and gas platforms vary by size, volume of production, type of production, and geographic location. Platform sizes range from one well, in Gulf of Mexico installations, to approximately 100 wells at artificial islands off the northern coast of Alaska. The volume of production on a platform ranges from several barrels a day to over 100,000 barrels per day. A given platform may produce oil, both oil and gas, or only gas. Platform locations include the Gulf of Mexico, the Pacific, and Cook Inlet, Alaska. Production began from artificial islands in 1987 in the Beaufort Sea region of Alaska. Future production may occur in other Arctic regions and off the Atlantic Coast.

The economics of oil and gas production and pollution control differ among platforms because of this variability of platform features. To capture these differences, representative model projects have been developed for the various geographical areas. The projects reflect variations in three parameters:

- Geographic region
- Size (number of wellslots)
- Type of production (oil, gas, or both)

The model projects have been reviewed and updated from those described in Economic Impact Analysis of Proposed Effluent Limitations and Standards for the Offshore Oil and Gas Industry (ERG, 1985).

A.1 GENERAL PARAMETER CATEGORIES

The model projects presented below reflect three key factors: geographic region, size, and production type. In all, 34 model projects are presented. They characterize the range of platform types expected to be installed during the study period.

A.1.1 Geographic Region

Offshore oil and gas deposits are known or are posited for:

- Atlantic - North, Mid- and South Atlantic
- Gulf of Mexico - offshore Florida, Alabama, Mississippi, Louisiana, and Texas
- Pacific - California, Oregon and Washington
- Alaska - Beaufort Sea, Chukchi Sea, Hope Basin, Norton Basin, St. Matthew Hall, Navarin Basin, Aleutian Basin, Bowers Basin, Aleutian Arc, St. George Basin, North Aleutian Basin, Cook Inlet, Shumagin, Kodiak, and Gulf of Alaska

These areas are shown in Figures A-1 and A-2.

These four regions -- Atlantic, Gulf, Pacific, and Alaska -- differ significantly with respect to the principal factors affecting offshore economics (geology, depth, weather, productivity, etc.). They are also geographically separate. Accordingly, models are developed for each of the four regions. Within Alaska, weather and geologic conditions vary from region to region, so projects are developed for four separate areas of the state -- Cook Inlet, Beaufort Sea, Norton Basin, and Navarin Basin.

A.1.2 Number of Well Slots

Platform size is the second key variable. Model projects within the regions are designed to reflect the different sizes of existing and planned structures.

For the Gulf, the selection of model structure sizes is based on the information in the MMS Platform Inspection System, Complex/Structure Data Base as of March 1988. Table A-1 summarizes the number of structures in the Gulf of Mexico by the number of available wellslots. The most predominant is a single wellslot structure where four out of five have no production equipment. Given the large number of these structures we model a "Gulf 1a" as a single well structure with no production equipment and a "Gulf 1b" as a single well structure with production equipment. Other projects chosen to represent the region are structures with 4, 6, 12, 24, 40, and 58 wellslots. The larger structures are expected to become more prevalent in the deeper waters.

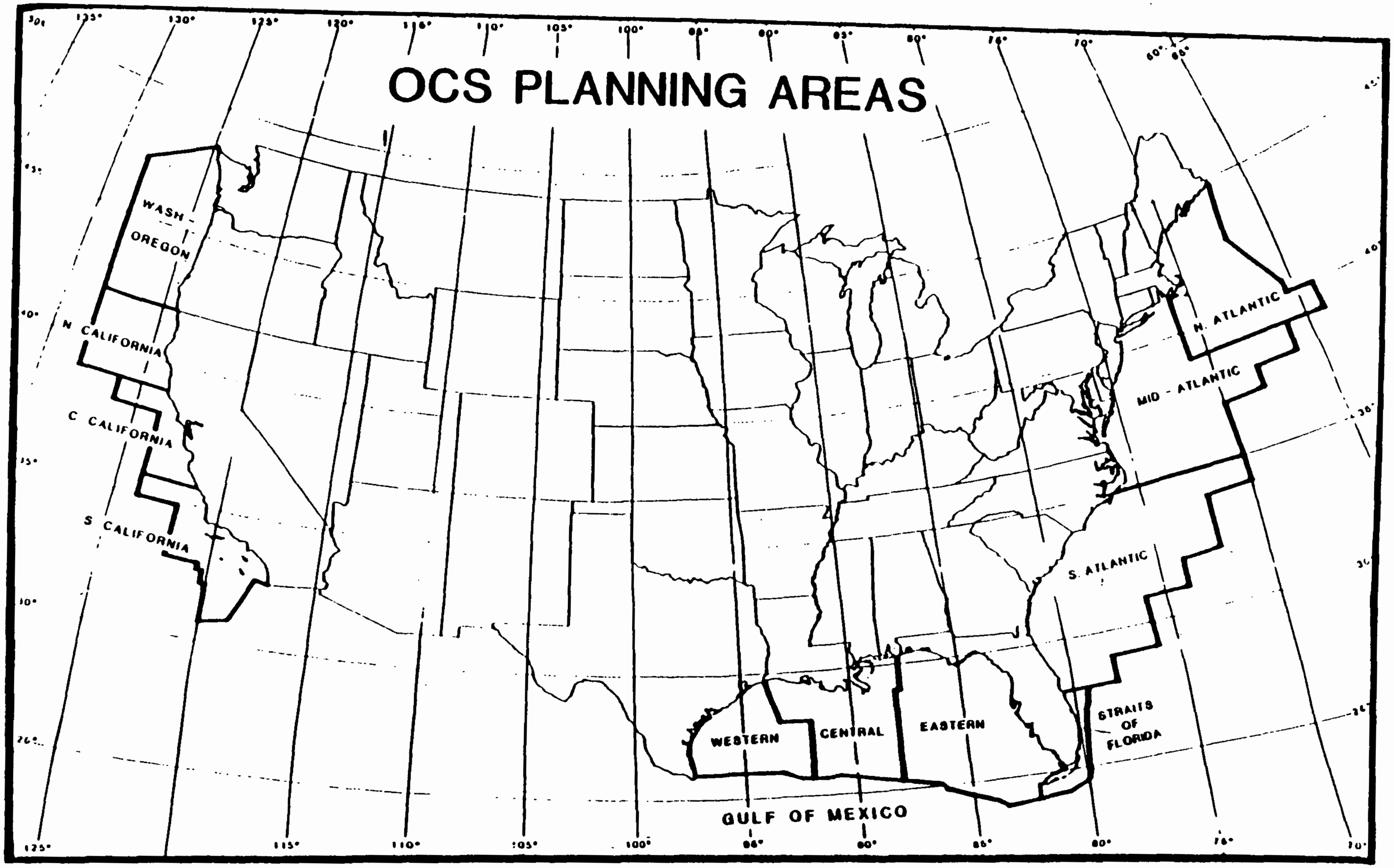

Figure A-1. OCS Planning Areas: Lower 48 States

Source: 5-Year Leasing Program Mid-1987 to Mid-1992, Minerals Management Service, April 1987.

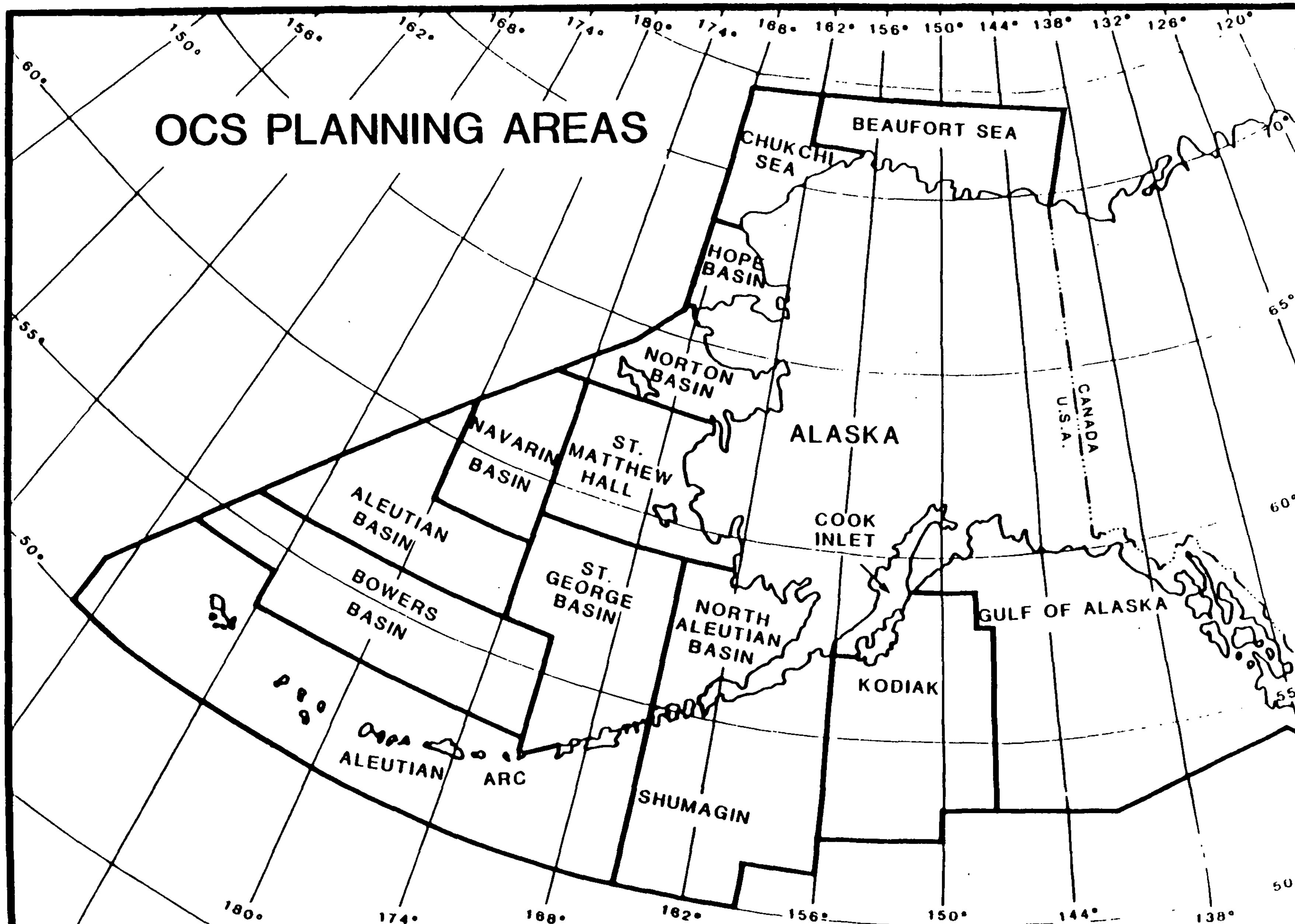

Figure A-2. OCS Planning Area: Alaska.

Source: 5-Year Leasing Program Mid-1987 to Mid-1992, Minerals Management Service, April 1987.

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TABLE A-1
NUMBER OF STRUCTURES BY THE NUMBER OF WELLSLOTS AVAILABLE
GULF OF MEXICO, MARCH 1988

Number of Wellslots Available	Number of Structures	Production Equipment Yes	Production Equipment No
1	1,283	20.0%	80.0%
2	207	34.8%	65.2%
3	143	49.7%	50.3%
4	203	60.6%	39.4%
5	37	75.7%	24.3%
6	181	82.3%	17.7%
7	31	90.3%	9.7%
8	79	94.9%	5.1%
9	80	93.8%	6.3%
10	31	96.8%	3.2%
11	12	100.0%	0.0%
12	287	92.3%	7.7%
13	32	100.0%	0.0%
14	20	95.0%	5.0%
15	29	89.7%	10.3%
16	33	97.0%	3.0%
18	152	95.4%	4.6%
19	2	100.0%	0.0%
20	9	77.8%	22.2%
21	23	91.3%	8.7%
22	5	80.0%	20.0%
23	3	100.0%	0.0%
24	121	95.9%	4.1%
25	6	66.7%	33.3%
26	5	80.0%	20.0%
27	3	100.0%	0.0%
28	9	100.0%	0.0%
30	2	100.0%	0.0%
32	5	0.0%	100.0%
35	1	100.0%	0.0%
36	3	100.0%	0.0%
40	6	100.0%	0.0%
58	1	100.0%	0.0%
62	1	100.0%	0.0%
Missing	52		
TOTAL	3,097		

Note: Blanks indicate no structures with intermediate numbers of wellslots.

Source: MMS Platform Inspection System, Complex/Structure Data Base, March 1988.

Table A-2 summarizes the number of wellslots per platform in <u>Pacific</u> OCS waters. Existing and planned structures range from 15 to nearly 100 wellslots, with an average of 55 wellslots per platform (MMS, 1986a). Three structures of varying sizes are chosen to model the Pacific region. The associated number of wellslots are 16, 40, and 70.

In the <u>Atlantic</u> and in most regions of <u>Alaska</u>, there are no existing platforms. The size and configuration of platforms in these regions will evolve as successful discoveries are made and developed. As a result, there is no basis upon which to define a variety of platform sizes in the Atlantic and the Alaskan regions. In each region, one typical size is selected based on available projections or engineering studies. For example, the number of wells projected for Arctic projects is based on the information in OTA 1985. The selected platform sizes are:

- Atlantic - 24 wellslots
- Cook Inlet - 12 or 24 wellslots depending on type of production
- Beaufort Sea - 48 wellslots
- Norton Basin - 34 wellslots
- Navarin Basin - 48 wellslots

In the Beaufort Sea, two configurations are modeled: a gravel island and a platform. (See Section A.2.4 for further description of these configurations.)

Based on the six regions and the size categories within each region, a total of 17 region/size categories are defined. These are shown in the left-hand column of Table A-3.

A.1.3 Type of Production

The type of production is the third variable in defining the model projects. Crude oil, natural gas, or both may be produced at a platform depending on the reservoir and the economics of recovery. The options are: oil-only, oil and gas, and gas-only.

In the <u>Gulf</u>, the MMS data indicate that, where the type of production is known, very few (under 5 percent) of the structures produce only oil. We maintain oil-only versions of the Gulf models to evaluate the costs of BAT regulations because the composition of the effluent differs between oil-only

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TABLE A-2
NUMBER OF WELLSLOTS ON PACIFIC OCS PLATFORMS

	Platform Name	Number of Wellslots	Year Installed	Water Depth (ft)
Existing	A	57	1968	188
	B	63	1968	188
	C	60	1977	193
	Edith	72	1983	161
	Ellen	80	1980	265
	Eureka	60	1984	700
	Gail	36	1987	739
	Gilda	96	1981	210
	Gina	15	1980	95
	Grace	48	1979	318
	Habitat	24	1981	303
	Harvest	50	1985	670
	Hermosa	48	1985	602
	Henry	28	1979	291
	Hidalgo	56	1987	430
	Hillhouse	60	1969	190
	Hogan	66	1967	150
	Hondo	28	1976	842
	Houchin	60	1968	151
	Irene	72	1985	242
Proposed	Hacienda	48	--	300
	Harmony	60	1992	1300
	Heritage	60	1992	1075
	Julius	70	1989	478
Average Number of Wellslots		54.9		

Source: MMS, 1986a; Ocean Industry, 1987a.

TABLE A-3

DISTRIBUTION OF OIL, OIL/GAS, AND GAS PRODUCING PLATFORMS BY REGION AND SIZE

REGION AND WELLSLOT SIZE	PRODUCTION TYPE OIL	OIL/GAS	GAS	COMMENTS
Gulf 1a[a]	Yes	Yes	Yes	
Gulf 1b[a]	Yes	Yes	Yes	
Gulf 4	Yes	Yes	Yes	
Gulf 6	Yes	Yes	Yes	
Gulf 12	Yes	Yes	Yes	
Gulf 24	Yes	Yes	Yes	
Gulf 40	Yes	Yes	No	No gas-only platforms among large Gulf platforms.
Gulf 58	Yes	Yes	No	No gas-only platforms among large Gulf platforms.
Atlantic 24	No	Yes	Yes	
Pacific 16	No	Yes	Yes	
Pacific 40	No	Yes	No	No gas-only platforms among large Gulf platforms.
Pacific 70	No	Yes	No	No gas-only platforms among large Gulf platforms.
Cook Inlet 12/24	No	Yes	Yes[b]	
Beaufort Sea 48				
- Gravel island	Yes	No	No	No infrastructure for gas delivery.
- Platform	Yes	No	No	No infrastructure for gas delivery.
Norton Basin 34	Yes	No	No	No infrastructure for gas delivery.
Navarin 48	Yes	No	No	No infrastructure for gas delivery.

Source: ERG model project configurations based on typical projects reported in the Department of the Interior Mineral Management Service platform inspection system, complex/structure database, and the literature.

[a]The Gulf 1a shares production equipment with three other single-well stuctures while the Gulf 1b has its own production equipment.

[b]The gas-only case is modeled as 12 wells.

and oil-and-gas production. For the projected platforms, all Gulf platforms that produce oil are assumed to have associated gas as well. There are no gas-only platforms among large Gulf platforms. Only small projects (less than 40 wellslots) are assumed to produce only gas.

The same pattern is found in the Pacific, where the large projects produce oil with gas (but not gas-only) and small projects produce oil-with-gas or gas-only. Telephone conversations with W. Guerard, California Department of Conservation, indicates that as an oil field gets older, it produces less gas but that all oil fields produce some gas (Guerard, 1989). All projected platforms that produce oil are assumed to have associated gas as well for evaluating the pollutant removals from produced water effluent guidelines.

In the Atlantic, the 24-wellslot platform is assumed to produce oil with gas or only gas. In Alaska, projects in the Cook Inlet are assumed to produce oil with gas or only gas. For the Arctic regions, there is no infrastructure to deliver gas from these regions to the Lower 48 States nor is such infrastructure planned for the next ten years, so just oil-only projects are proposed for these regions.

A.2 DESCRIPTION OF MODEL PROJECTS

A.2.1 Gulf of Mexico Model Projects

Gulf 1, 4 and 6-Well Platforms

Small platforms in the Gulf either have their own production facilities or are simple superstructures (i.e., well protectors) that ship produced hydrocarbons (before water separation) to a central onshore or offshore production facility. Platforms in the latter category are referred to as satellite facilities. By servicing several platforms, centralized facilities offer economies of scale in oil and gas production over small platform structures with their own production equipment. Satellite platforms cannot be used in all situations, however. If the platform is in a remote location so that the cost of additional pipelines outweighs the cost advantage of central processing, or the production from the platform is transported via intercompany pipelines that do not accept crude unless it is already separated from the produced water, then the production facility is located directly on the specific platform.

The MMS Platform Inspection System provides information on the number of wellslots per OCS platform and whether platforms have their own production equipment. Table A-1 summarizes the data in the 1988 MMS files. Two models are used for a single wellslot structure in the Gulf, one without production equipment and one with production equipment. These are referred to as the Gulf 1a and Gulf 1b models, respectively. The majority of 4- and 6-wellslot structures have their own production equipment and are modeled as such in this report.

Gulf 12-Well and 24-Well Platforms

These two model projects represent typical medium-sized production structures common in the Gulf (see Table A-1). The DOI-MMS Platform Inspection System Reports are used to define representative features of the 12- and 24-wellslot platforms (Tables A-4 and A-5). The typical 12-wellslot steel jacket platform occurs in 0 to 200 feet of water (67 feet in the model project), 0 to 10 miles offshore (6 miles in the model project). Of the 12 slots, an average of 10 are in use for production at any one time (10 in the model project). The typical 24-wellslot steel-jacket platform occurs in 50-500 feet of water (100 feet in the model project) and 5 to 50 miles offshore (20 in the model project). Of the 24 slots, an average of 18 are in use for production at any time (18 in the model project).

Gulf 40 Well Platform. The Gulf 40-well case represents those platforms expected to produce large reservoirs in water depths averaging 200 feet and of distances from shore averaging 50 miles. A selection of existing structures in this size range is described in Table A-6. Again, ERG uses the MMS Platform Inspection System Reports to define representative features of this model project. Platforms in this case are expected to be constructed on the far offshore tracts now being leased. No gas-only platforms are expected to be in this category. Of the 40 wellslots, an average of 32 are in use for production at any time.

Gulf 58 Well Platform. The largest model project in the Gulf is based on platforms Cognac and Bullwinkle. Both are 60-slot steel jacket platforms. Cognac, with an overall length of 1,265 feet, was installed in 1978 in Mississippi Canyon while the 1,615-foot Bullwinkle is scheduled to be installed in Green Canyon this year. Cognac and Bullwinkle are set approximately 15 and 90 miles offshore at depths of 1,023 and 1,353 feet,

TABLE A-4

SAMPLE 12-WELL STRUCTURES USED IN SELECTING 12-WELL MODEL PROJECT

AREA	BLOCK	WATER DEPTH (FEET)	MILES FROM SHORE	WELL-SLOTS	SLOTS IN USE	YEAR INSTALLED
West Cameron	513	170	93	12	8	1974
East Cameron	222	110	67	12	12	1973
South Timbalier	161	117	32	12	9	1964
Main Pass	042	30	11	12	12	1965
Main Pass	043	27	10	12	12	1967
East Cameron	033	42	8	12	10	1972
West Delta	095	150	27	12	9	1968
West Cameron	522	177	95	12	6	1978
Matagorda Island	665	74	15	12	7	1979
Ship Shoal	168	58	27	12	8	1973

Source: Department of the Interior, Mineral Management Service, Offshore Inspection System, Complex/Structure List, April 23, 1987.

TABLE A-5

SAMPLE STRUCTURES USED IN SELECTING 24-WELL MODEL PROJECT

AREA	BLOCK	WATER DEPTH (FEET)	MILES FROM SHORE	WELL-SLOTS	SLOTS IN USE	YEAR INSTALLED
High Island	349A	278	115	24	9	1979
East Cameron	322	230	95	18	16	1975
Grand Isle	081	177	38	24	17	1971
Vermilion	023	36	6	25	4	1977
Eugene Island	256	137	53	18	7	1977
South Marsh Island	128	225	75	24	18	1975
South Pass	037	108	7	24	13	1962
South Timbalier	026	60	8	18	18	1971
South Timbalier	026	55	8	26	26	1971
South Timbalier	026	60	8	24	18	1979
Ship Shoal	225	146	54	21	18	1971
Vermilion	247	139	65	24	14	1972
Vermilion	321	205	87	24	22	1972
Mississippi Canyon	311	425	46	24	19	1978
Grand Isle	022	55	8	24	23	1957

Source: Department of the Interior, Mineral Management Service, Offshore Inspection System, Complex/Structure List, April 23, 1987.

TABLE A-6

SAMPLE STRUCTURES USED IN SELECTING 40-WELL MODEL PROJECT

AREA	BLOCK	WATER DEPTH (FEET)	MILES FROM SHORE	WELL-SLOTS	SLOTS IN USE	YEAR INSTALLED
Main Pass	153	290	14	32	32	1970
South Marsh Island	130	215	82	36	36	1975
South Marsh Island	130	215	82	40	31	1978
South Marsh Island	130	215	82	36	36	1974
South Marsh Island	130	216	82	36	36	1975
West Delta	080	102	13	30	23	1971
The Elbow	331	241	80	35	35	1972
East Breaks	160	935	110	40	2	1981
South Pass	070	290	9	40	40	1977
South Pass	070	264	9	40	40	1974
South Pass	065	300	9	32	32	1969

Source: Department of the Interior, Mineral Management Service, Offshore Inspection System, Complex/Structure List, April 23, 1987.

respectively (Offshore 1986, MMS Offshore Inspection System). Information on the Gulf projects is summarized in Table A-7.

A.2.2 Atlantic Model Projects

Platform configurations for the Atlantic are speculative since no economic petroleum discoveries have been made to date (MMS, 1986b). Based on the physical environments, the mid- and South Atlantic platforms can be expected to be similar to California production platforms. The North Atlantic platforms will probably be modified North Sea-type platforms. In the final EIS for their 5-year leasing program, the MMS projects from 23 to 35 production wells per Atlantic platform (MMS, 1987). A 24-wellslot platform is therefore expected to be representative of economically feasible projects in the Atlantic. The model project water depth (300 feet) and distance from shore (100 miles) are based on the location of exploratory wells in Georges Bank and the Baltimore Canyon (MMS, 1981, and MMS, 1983). Information on the Atlantic projects are summarized in Table A-8.

A.2.3 Pacific Model Projects

Most of the platform development in the Pacific is expected to occur off the coast of Southern California. The California offshore area is characterized by several old, fully developed fields and by high-potential areas in the Santa Maria Basin, the Santa Barbara Channel, and off Long Beach. Most of the current production is oil; in 1986 the oil/gas ratio was 531 ft^3/bbl. There are only 21 nonassociated gas wells currently producing offshore California; 6 of these wells are in state waters. Habitat, the Pitas Point platform with 12 wells producing in 1986, is the only nonassociated gas producer to date. Virtually all future production is expected to be oil (California, 1987). Platform types in newly discovered fields are used as the basis for the Pacific model projects. Most of these are in the peak production range of 20,000 to 72,000 barrels oil per day (bopd).

Platforms producing from smaller reservoirs are represented by the 16-wellslot model project that is patterned after the 6,000 bopd Platform Gina. The larger reservoirs are represented by the 40-wellslot project patterned after Platform Gail or the 70-wellslot project patterned after Platform Edith. The number of producing wells expected with each project are 14, 33 and 60, respectively. This information is summarized in Table A-9.

TABLE A-7

PROJECT DESCRIPTIONS

GULF OF MEXICO

PARAMETER	GULF OF MEXICO PROJECTS						
	GULF 1	GULF 4	GULF 6	GULF 12	GULF 24	GULF 40	GULF 58
Platform typewell	well protector	steel jacket	steel jacket	steel jacket	steel jacket	steel jacket	steel jacket
Location							
- state waters	yes	yes	yes	yes	yes	no	no
- Federal OCS waters	yes	yes	yes	yes	yes	yes	yes
Distance from shore							
- mi	3	3	3	6	20	50	100
- km	4.8	4.8	4.8	9.7	32.0	80.4	161
Water depth							
- ft	33	33	33	66	100	200	590
- m	10	10	10	20	30	60	180
Number of wellslots	1	4	6	12	24	40	58
Number of producing wells	1	4	6	10	18	32	50

Source: ERG estimates.

TABLE A-8

PROJECT DESCRIPTION

ATLANTIC REGION

PARAMETER	ATLANTIC 24
Platform type	tension leg platform
Location	
- state waters	no
- Federal OCS waters	yes
Distance from shore	
- mi	100
- km	161
Water depth	
- ft	300
- m	90
Number of wellslots	24
Number of producing wells	20

Source: ERG estimates.

TABLE A-9

PROJECT DESCRIPTIONS

PACIFIC REGION

PARAMETER	PACIFIC 16	PACIFIC 40	PACIFIC 70
Platform type	steel jacket	steel jacket	steel jacket
Location			
- state waters	no	yes	no
- Federal OCS waters	yes	yes	yes
Distance from shore			
- mi	5	3	5
- km	8.0	4.8	8.0
Water depth			
- ft	300	300	1,000
- m	90	90	300
Number of wellslots	16	40	70
Number of producing wells	14	33	60

Source: ERG estimates.

A.2.4 Alaskan Model Projects

The Alaskan offshore area is quite diverse. Platform designs range from conventional platforms in Cook Inlet to severe weather structures in the Arctic areas. Model projects are selected to span a range of conditions in the Alaskan offshore areas.

Cook Inlet. This model project represents the platform types expected to be used in southern Alaska, that is Cook Inlet/Shelikof Strait, Bristol Bay, and Gulf of Alaska. This region is free of Arctic ice and has moderate environmental conditions. Accordingly, conventional platform designs similar to existing Cook Inlet structures, including the recently installed Steelhead platform, define the model projects.

Southern Alaska platforms may be expected to produce oil, gas or both. Table A-10 lists information about existing platforms in Cook Inlet (Alaska, 1984 and Ocean Industry, 1987b). Although these are in the Coastal subcategory, they do provide some information for future offshore projects in Alaska. There are 15 platforms with a total of 326 drilled wells. For oil and gas projects, a 24-well platform with 20 producers is proposed. A 12-wellslot model project with 10 producing wells is selected to represent gas-only projects in the region. Both the 24-wellslot and 12-wellslot structures are assumed to be in 50 meters of water and 20 miles offshore.

Arctic Alaska Model Projects

The first Arctic offshore production began at the end of 1987. The Endicott field lies 10 miles northeast of Prudhoe Bay in the State waters of the Beaufort Sea. The field was discovered in 1978 and production began in October 1987 (Alaska, 1988). This project forms the basis for the Beaufort Sea gravel island project described below. The other Arctic projects are based on the 1985 report from the Office of Technology Assessment entitled Oil and Gas Technologies for the Arctic and Deepwater (OTA, 1985).

Beaufort Sea Gravel Island. The plan to develop the Endicott field includes a 5-mile causeway into the shallow waters of the Beaufort Sea linking two artificial gravel islands. The islands are located some 2-1/2 miles off the coast in 4 to 12 feet of water. Some 80 to 120 development wells are

TABLE A-10

PLATFORMS IN COOK INLET

	INSTALLED	YEAR DRILLED	WELLS FIELD
N. Cook Inlet (gas-only)	A Platform	1968	12
Granite Point	Bruce	1966	17
	Anna	1966	26
	Granite Point	1966	17
Trading Bay	Spark	1968	7
	TSA	1968	9
	Monopod	1966	31
McArthur River	King Salmon	1967	24
	Grayling	1967	37
	Dolly Vardin	1967	36
	Steelhead	1987	36
Middle School Ground	Baker	1965	20
	A	1964	24
	C	1964	16
	Dillon	1965	14
Total			326

Source: Johnson, 1988.

planned. The ERG project is a single island with 48 wells, that is half the size of the Endicott project (Alaska, 1988; Drilling Contractor, 1987).

Beaufort Sea Platform. The Beaufort Sea platform is assumed to be located 20 miles offshore in 50 feet of water. This location has extremely low temperature conditions and is covered with ice 10 months out of the year. The OTA report lists this project as being developed from a gravel island but also notes that alternatives such as concrete, steel, hybrid structures built as caissons, or complete bottom-mounted units may be preferable, depending on site-specific conditions. The OTA scenario has seven island/platforms with a total of 271 wells; a footnote indicates that the number of wells is probably a minimum. The ERG project is a single 48-wellslot structure with 40 producing wells.

Norton Basin. The Norton Basin has a more "moderate" climate than the Beaufort Sea; ice coverage is only 8 months out of the year. On the other hand, platform designs must address strong bottom currents and storm surges. As with the Beaufort Sea scenario, the OTA report initially lists development as a set of four gravel islands with a total of 136 wells. The same footnote listing platform alternatives to the gravel island is given for the Norton Basin. The ERG model project assumes a 34-wellslot platform 40 miles from shore in 50-foot water with 28 producing wells.

Navarin Basin. The Navarin Basin has light-to-moderate conditions with 5-month coverage. In contrast to moderate ice conditions and temperature, the Navarin Basin is also marked by severe storms, wind-driven waves, spray-icing, and the potential for soft soil. The OTA report projects either a gravity platform or a steel, pile-founded structure depending on site conditions. The scenario is located 400 to 700 miles offshore in 450 feet of water. The OTA scenario consists of seven production platforms and two service platforms with a minimum of 271 wells. The ERG project is a single structure with 48 wellslots and 40 producing wells.

Table A-11 summarizes the information for the Alaska projects.

A.3 REFERENCES

Alaska 1984. 1984 Statistical Report, Alaska Oil and Gas Conservation Commission, n.d.

TABLE A-11

PROJECT DESCRIPTIONS

ALASKA

PARAMETER	COOK INLET OIL, OIL/GAS	COOK INLET GAS	BEAU-FORT GRAVEL ISLAND	BEAU-FORT PLATFORM	NORTON BASIN	NAVARIN BASIN
Platform type	steel jacket	steel jacket	gravel island	steel structure/ caisson	steel structure/ caisson	gravity plat-form
Location						
- state waters	yes	yes	yes	no	no	no
- Federal OCS waters	yes	yes	yes	yes	yes	yes
Distance from shore						
- mi	3	5	3	20	40	400-700
- km	5	8	5	32	64	640-1,130
Water depth						
- ft	50	50	15	50	50	450
- m	15	15	5	15	15	137
Number of wellslots	24	12	48	48	34	48
Number of producing wells	20	10	40	40	28	40

Source: ERG estimates.

Alaska 1988. 5-Year Oil and Gas Leasing Program, Alaska Department of Natural Resources, January 1988.

California 1987. 72nd Annual Report of the State Oil and Gas Supervisor, California Department of Conservation, 1987.

Drilling Contractor 1987. "Endicott oilfield development is on schedule," Drilling Contractor, August/September 1987, pp. 25-26.

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Guerard 1989. Personal communication between Maureen F. Kaplan, Eastern Research Group, and William Guerard, California Department of Conservation, 12 May 1989.

Johnson 1988. Individual well production printouts sent to Maureen F. Kaplan, Eastern Research Group, Inc., by Elaine Johnson, Alaska Oil and Gas Conservation Committee, 25 February 1988.

MMS 1981. U.S. Department of the Interior, Minerals Management Service, North Atlantic Summary Report, U.S. Geological Survey Open-file Report 81-601.

MMS 1983. U.S. Department of the Interior, Minerals Management Service, Mid-Atlantic Summary Report, October 1983.

MMS 1986a. U.S. Department of the Interior, Minerals Management Service, Pacific Summary Report/Index November 1984-May 1986, MMS 86-0060.

MMS 1986b. U.S. Department of the Interior, Minerals Management Service, Atlantic Summary Report/Index January 1985-June 1986, MMS 86-0071.

MMS 1987. U.S. Department of the Interior, Minerals Management Service, Proposed 5-Year Oil and Gas Leasing Program Mid-1987 to Mid-1992, Final Environmental Impact Statement, MMS 86-0127, January 1987.

Ocean Industry 1982. "Offshore Construction Report," Ocean Industry, March 1982.

Ocean Industry 1983. "Offshore Construction Report," Ocean Industry, March 1983.

Ocean Industry 1986. "1986 Platform Survey," Ocean Industry, March 1986, pp. 29-34.

Ocean Industry 1987a. "1987 Platform Survey," Ocean Industry, March 1987, pp. 64-68.

Ocean Industry 1987b. "Steelhead brings new life to aging Cook Inlet field," Ocean Industry, November 1987, pp. 35-36.

Offshore 1986. "The Gulf of Mexico," Offshore, February 1986, pp. 38-45.

OTA 1985. Oil and Gas Technologies for the Arctic and Deepwater, Office of Technology Assessment, Washington, D.C.

APPENDIX B

BASE CASE TIMING OF PROJECT DEVELOPMENT

B.1 PHASES OF PROJECT DEVELOPMENT

In developing the economic models for the 39 model projects, ERG assumes that there are four phases of project development: exploration, delineation, development, and production. The exploration phase is the time from the lease sale through exploration well drilling. After a discovery, additional wells may be drilled to delineate the extent of the reservoir. This occurs during the delineation phase. The development phase includes planning, building, and installing the platform, and drilling development wells. The production phase of the project is the time during which oil and/or gas is being produced. ERG assumes that the exploration and delineation phases of the model projects are discrete in time and that the development phase overlaps the production phase. Six wells are drilled each year on platforms with up to 12 wellslots (one drilling rig operating) and 12 per year are drilled on larger platforms (two drilling rigs operating). Five-sixths of these wells are production wells and one-sixth are service wells. Production wells are in full production the year they are drilled.

B.2 DURATION OF PROJECT DEVELOPMENT PHASES

The geographic region (climate) in which the project is located, the size of the platform, water depth, distance from shore, and any previous oil and gas development in the area are important determinants of project timing. Length of time for project development varies from 1 year between lease sale and start of production for a single well structure in the Gulf of Mexico (located close to shore in 40 feet of water and in a highly developed area) to 12 years for the Beaufort Sea 48-well platform (located in extremely severe climate conditions). The data sources for each region are discussed separately below.

B.2.1 Gulf of Mexico

For the Gulf of Mexico, project timing is developed from a series of MMS and industry sources (MMS, 1982; MMS, 1986a; and MMS, 1986b). Exploratory drilling is assumed to begin within a year of the lease sale. Figure B-1 shows the time to first spud date (i.e., time when drilling begins on the first exploratory well) for all OCS sales held from 1975 through 1984. The average annual time to first spud is less than half a year for this time period, although the times for any given sale range from a few weeks to 11 months.

No delineation wells are proposed for the small Gulf projects (Gulf 1, Gulf 4, and Gulf 6) so no time accrues between the start of exploration and the start of delineation for these projects. For the Gulf 12, Gulf 24 and Gulf 40 projects, exploratory wells are drilled within a year of lease sale. An additional year is spent in exploratory drilling for the Gulf 58 project.

One year is assumed to occur by the start of development in the Gulf 4 and Gulf 6 projects. No additional time is assumed to pass between the start of delineation and the start of development for the Gulf 12, Gulf 24 and Gulf 40 projects. Two years between the start of delineation and the start of development is assigned to the Gulf 58 project.

For the time between the start of the development to the start of operation, one year is assigned to the Gulf 1, Gulf 4, and Gulf 2x5 projects; 2 years to the larger oil and oil/gas projects; and 3 years to the Gulf 24 gas-only project.

The timing assumptions are summarized in Table B-1 for the Gulf of Mexico projects. Figure B-2 shows the time from lease sale to initial production for the 1975 to 1984 period. Times range as short as 5 months to over 3 years. Since Figure B-2 shows the time to earliest production, and we are developing "typical projects," our time frame should be and is at the higher end of the range. The 6-year schedule for the Gulf 58 project is based on Shell's Bullwinkle project - a 60-slot platform to be installed in 1989 on a tract leased in OCS Sale 72 in 1983 (OGJ, 1988c). The time from lease sale to the start of operation ranges from 2 to 6 years. This is consistent with the information in (1) MMS 1986b, where tracts leased in the April 1984 sale were in production by mid-1986, but not tracts leased in July 1984 or later sales; (2) MMS 1987a, where projects in federal waters are assumed to take 4 years for the central Gulf, 5 years for the western Gulf, and 8 years for the

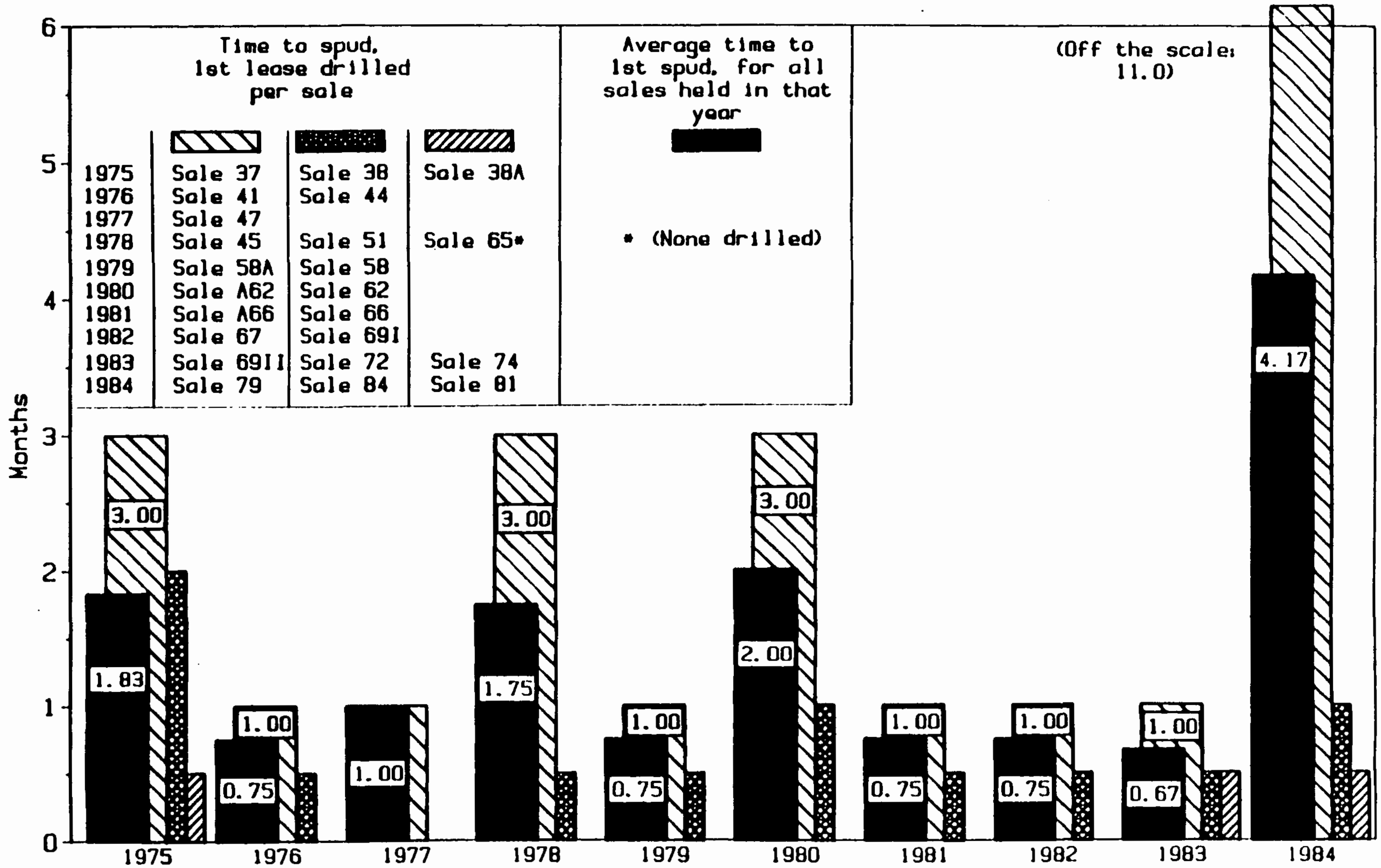

Figure B-1. Gulf of Mexico: Time From Lease Sale to First Spud Date.

Source: MMS 1986a.

TABLE B-1

PROJECT TIMING

GULF OF MEXICO

TIMING	MODEL PROJECTS										
	OIL AND OIL/GAS							GAS ONLY			
	GULF 1	GULF 4	GULF 6	GULF 12	GULF 24	GULF 40	GULF 58	GULF 4	GULF 2x5	GULF 12	GULF 24
Years between lease sale and start of exploration	0	0	0	0	0	0	0	0	0	0	0
Years between start of exploration and start of delineation	0	0	0	1	1	1	2	0	0	1	1
Years between start of delineation and start of development	0	1	1	0	0	0	2	1	1	0	0
Years between start of development and start of operation	1	1	1	2	2	2	2	1	1	2	3
Total years between lease sale and start of operation	1	2	2	3	3	3	6	2	2	3	4

Source: ERG estimates.

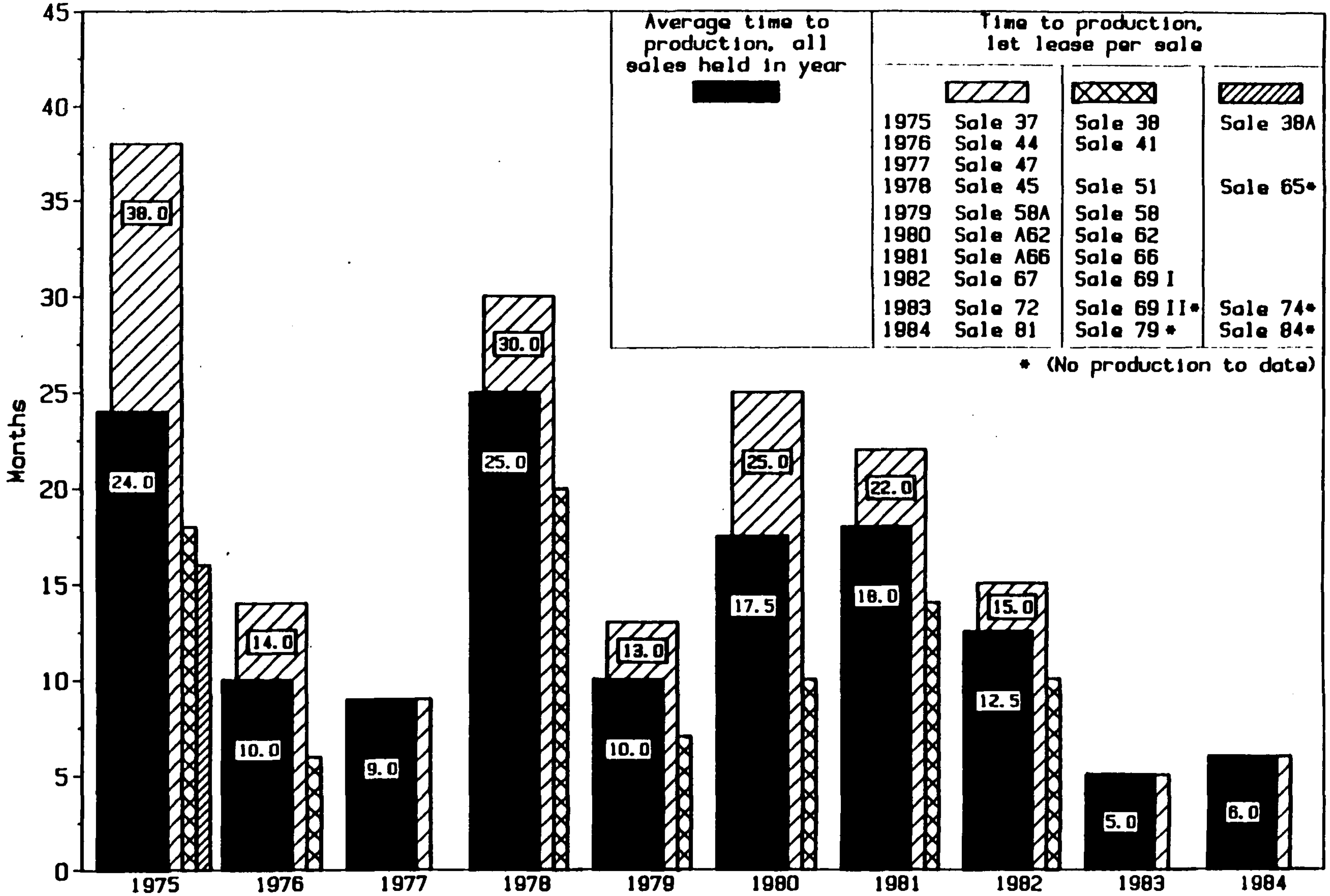

Figure B-2. Gulf of Mexico: Time From Lease Sale to Initial Production.

Source: MMS 1986a.

eastern Gulf; and (3) OTA 1985, where production lead times of 2 years are proposed for the Gulf area.

B.2.2 Pacific

The Pacific region required updating from the 4 to 5 years allowed from base sale to start of operation in ERG 1985. Table B-2 summarizes the project timing for several recent and projected platforms. The time from lease sale to start of operation ranges from 6 to 20 years. Changing environmental regulations and litigation are credited with a 5-year delay between platform installation and production for the Hondo A platform and a 15-year delay in confirmation drilling on Tract P-0205 (Ocean Industry, 1986, and 1987a). Platform Gail was launched on Tract P-0205 in April 1987. While Gail was enroute from its construction in Japan, the California Coastal Commission ruled that it was built to too-strict environmental and safety standards. The platform was towed and then beached until the project was deemed suitable (Ocean Industry, 1987a, and 1987d).

In light of these developments, timing for the Pacific projects has been revised from that given in ERG 1985. Figure B-3 shows the time from lease sales to first spud date in the Pacific. The times range from less than 1 month to 17 months. We therefore allocate 1 year between lease sale and the start of exploration for the Pacific model projects.

Table B-2 indicates that discovery wells typically occurred 2 to 3 years after lease sale. The time between the start of exploration and the start of delineation when the discovery would occur is therefore 1 to 2 years. Platforms have been set 4 or more years from the lease sale, or from 1 to 4 years after the start of delineation. Production usually occurs within 1 to 3 years after the platform has been set depending on how much other construction is required. For example, at the end of 1987, platforms Harvest and Hermosa had had wells drilled but were waiting for onshore processing facilities to be completed prior to going into production (Rau, 1987).

This information is summarized in Table B-3. The time from lease sale to start of operation now ranges from 5 to 10 years. The revised project timing also agrees with the information in Figure B-4 on the time from lease sale to initial production. The range in project timing corresponds well to that in the U.S. for the 5-year leasing plan (MMS, 1987a) where West Coast projects

TABLE B-2

PROJECT TIMING FOR RECENT PACIFIC COAST PLATFORMS

	SANTA MARIA BASIN FIELDS						SANTA BARBARA CHANNEL FIELDS		
	PT. ARGUELLO			PT. PEDER-NALES	SAN MIGUEL	ROCKY POINT	SOCK-EYE	HONDO	PES-CADO
	HARVEST	HERMOSA	HIDALGO	IRENE	JULIUS	HACIENDA	GAIL	HARMONY	HERITAGE
Water depth	670	602	430	242	478	300740	1,207	1,004	
- # slots	50	48	56	72	70	4836	60	60	
- # slots drilled	42	40	45	43	--	--	25	--	--
Lease sale	1979	1979	1981	1981	1981	1981	1968	1968	1968
Discovery	1982	1981	--	--	1983	1984	1970	--	--
Platform set	1985	1985	1987	1985	1989	--	1987	1992	1992
Initial production	1988	1988	1988	1986	1990	--	1988	--	--
Peak production									
- oil bopd	72,000	27,000	20,000	20,000	40,000	--	--	50,000-60,000	50,000-60,000
- gas MMcfd	--	25	10	13.3	--	--	--	40-50	70-100
- year	1989	1996	1996	1987	--	--	--	--	--
Years before lease to production	10	9	15	6	9	--20	--	--	

Note: -- means information not available.

Source: Ocean Industry, 1986, 1987a,b,c; MMS, 1986c; Offshore, 1987a.

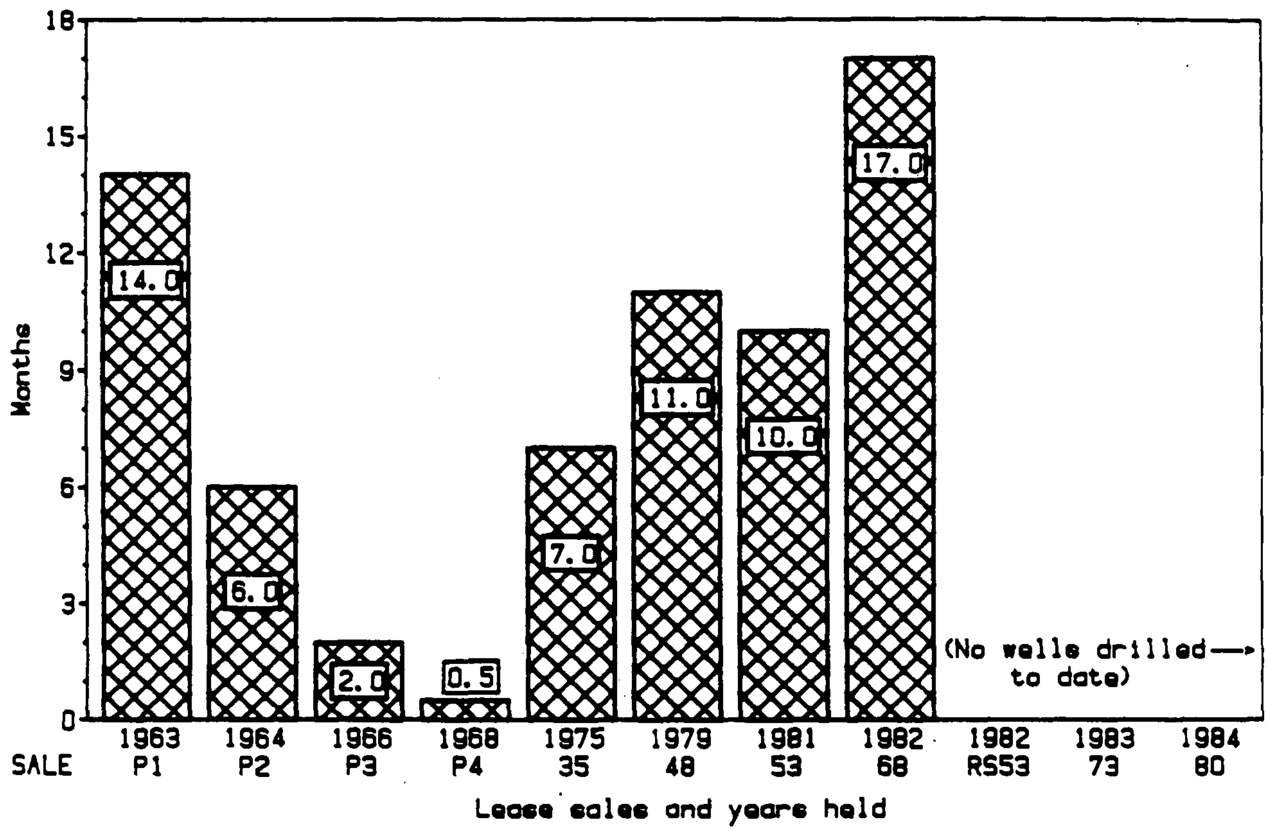

Figure B-3. Pacific Region: Time from lease sale to first spud date.

Source: MMS 1986a.

TABLE B-3

PROJECT TIMING

PACIFIC REGION

TIMING	OIL AND OIL/GAS			GAS ONLY
	PACIFIC 16	PACIFIC 40	PACIFIC 70	PACIFIC 16
Years between lease sale and start of exploration	1	1	1	1
Years between start of exploration and start of delineation	1	2	2	1
Years between start of delineation and start of development	1	3	5	2
Years between start of development and start of operation	2	2	2	2
Total years between lease sale and start of operation	5	8	10	6

Source: ERG estimates.

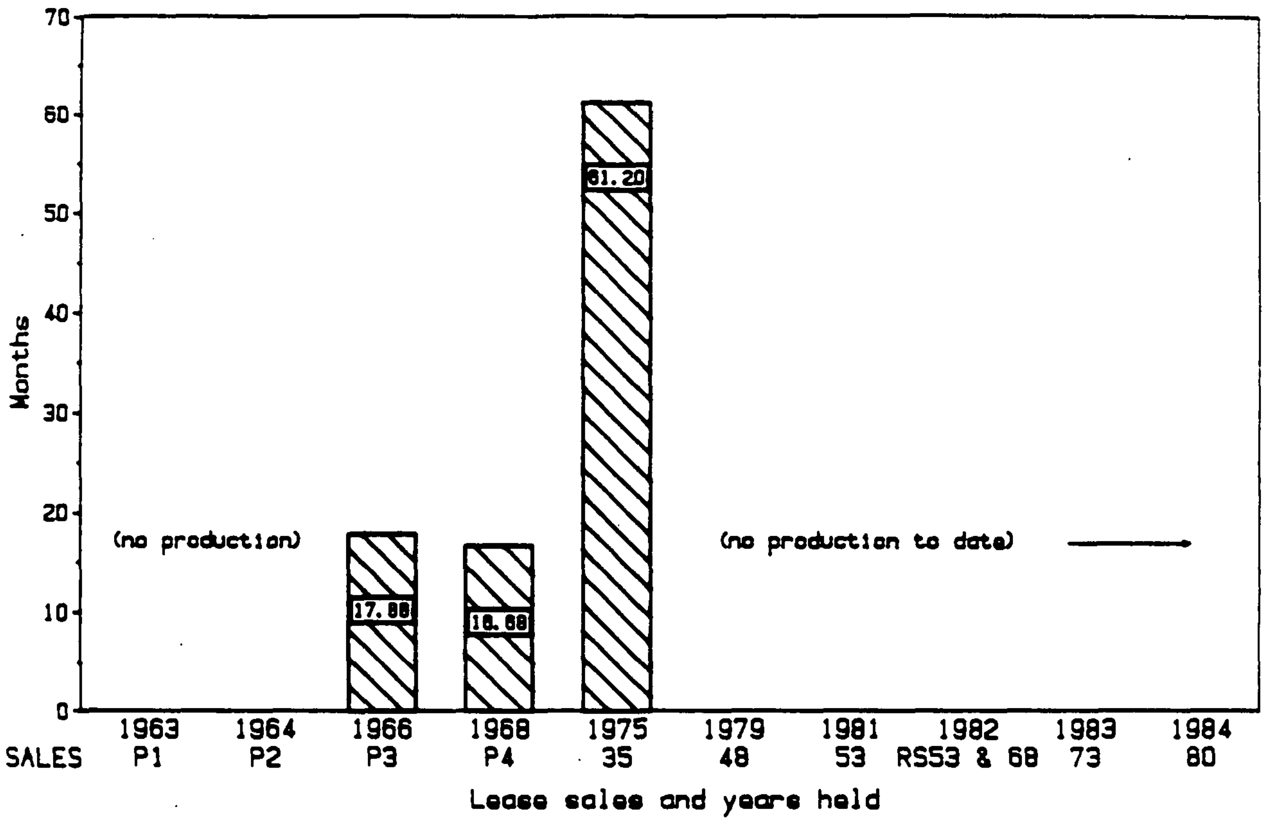

Figure B-4. Pacific Region: Time from lease sale to initial production.
Source: MMS 1986a.

take from 5 to 10 years from lease sale to initial production. For deepwater projects off California, OTA 1985 estimates a production lead time of 10 years.

The delays are having an effect on whether the projects are economical. Platforms Independence and Heather appear to have been cancelled (Ocean Industry, 1987b). ARCO filed lawsuit in October 1987 seeking compensation from the State Lands Commission and Santa Barbara County for an unlawful taking of property by denying ARCO's permit for development until the cumulative effect of oil drilling offshore California can be thoroughly studied. ARCO's plan of exploration was approved in 1980 (Ocean Industry, 1987d).

B.2.3 Atlantic

There has been no development to date in the Atlantic OCS region. Estimates of project timing, therefore, are hypothetical. The 7- to 9-year span developed in ERG 1985 corresponds well with the 6- to 9-year range developed in MMS 1987a (Table IV.A.1-1) for the 5-year leasing schedule. In MMS 1987, one year is allotted for the time from lease sale to start of exploration and production is assumed to occur in the same year as the platform is set. Given the delays seen between platform installation and production seen in Pacific OCS platforms (see Section B.2.2), we prefer to allocate 2 to 4 years to that part of the project. Table B-4 summarizes project timing for platforms in the Atlantic.

B.2.4 Alaska

Project timing varies greatly in Alaska depending upon where the project is located. For the Cook Inlet projects, the area is relatively free of severe climatic conditions and the region is mature in terms of oil and gas development, so many facilities are already in place. The platforms that exist in Cook Inlet are in the coastal subcategory. Information about these platforms can be used to estimate timing for model projects in a relatively ice-free area in offshore Alaskan waters. The Beaufort Sea/North Slope region now has the trans-Atlantic pipeline in place, while the Bering Sea is undeveloped. Project timing, then, is shortest in the Cook Inlet area and longer for the Arctic regions.

TABLE B-4

PROJECT TIMING

ATLANTIC REGION

TIMING	OIL AND OIL/GAS ATLANTIC 24	GAS ONLY ATLANTIC 24
Years between lease sale and start of exploration	1	1
Years between start of exploration and start of delineation	2	2
Years between start of delineation and start of development	2	2
Years between start of development and start of operation	2	4
Total years between lease sale and start of operation	7	9

Source: ERG estimates.

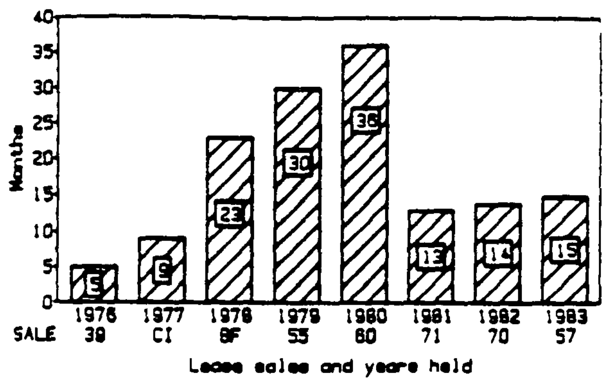

Figure B-5. Alaska Region: Time from lease sale to first spud date.

Source: MMS 1986a.

months. We allocate 1 year to the time between lease sale and the start of exploration for the Cook Inlet projects and 2 years for projects in other areas.

The Steelhead platform is the first platform to be installed in Cook Inlet since 1968. The jacket was installed in mid-1986 and production was expected to begin by the end of 1987. On this basis, 2 years are allocated for the years between the start of development and the start of production for the Cook Inlet projects (MMS, 1987b and Ocean Industry, 1987e).

In the Endicott field in the Beaufort Sea region, the final permits for development were issued in January 1985. By the end of 1986, the gravel project was completed and by the end of 1987 the equipment sealift was completed and initial production begun (Drilling Contractor 1987a and 1987b). On this basis, 3 years are allocated to the time from the start of development to the start of operation for the Beaufort gravel island, and platforms in the Beaufort Sea, Norton Basin, and Navarin Basin.

The Endicott field was discovered in 1978 and is coming into production by 1987 (Drilling Contractor, 1987b). A range of 7 to 10 years is allocated for the time between the start of exploration and start of operation for the Beaufort Sea gravel island projects. The Beaufort Sea platform is assumed to take one year longer than the Beaufort Sea gravel island because it is located further offshore and in deeper water. A total of 5 years is allocated to this period for the Cook Inlet projects.

Project timing assumptions for Alaska projects are summarized in Table B-5. The time span ranges from 6 years for projects in Cook Inlet to 12 years for projects in the Beaufort Sea. The project lead times for platforms in the Norton Basin (9 years), Navarin Basin (11 years), and the Beaufort Sea (12 years) correspond to those presented in OTA, 1985. This range is somewhat broader than that proposed in the EIS for the 5-Year Leasing Plan where Alaska projects take 9 to 12 years from lease sale to first development (MMS 1987a) to allow for more variation in the analysis. It is unlikely that projects in the well-developed Cook Inlet area would have a 9-year project lead time.

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TABLE B-5

PROJECT TIMING

ALASKA

TIMING	MODEL PROJECT						
	OIL					OIL/ GAS	GAS
	COOK INLET	BEAU-FORT GRAVEL ISLAND	BEAUFORT PLATFORM	NORTON BASIN	NAVARIN BASIN	COOK INLET	COOK INLET
Years between lease sale and start of exploration	1	2	2	2	2	1	1
Years between start of exploration and start of delineation	1	3	3	2	3	1	1
Years between start of delineation and start of development	2	3	4	2	3	2	2
Years between start of of development and start of operation	2	3	3	3	3	2	2
Total years between lease sale and start of operation	6	11	12	9	11	6	6

Source: ERG estimates.

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APPENDIX C

LEASE PRICES

The lease price for each model project is a function of four factors:

$$\text{Lease Price} = \text{Price per Tract} \times \frac{\text{Exploratory Wells}}{\text{Discovery Well}} \times \text{Ratio of Expected Production} \Big/ \frac{\text{Platforms}}{\text{Discovery Well}}$$

The price per tract is the average price paid for tracts in that region in 1986. These prices are described in Section C.1. The ratio of the number of successful exploratory wells ("discovery well") to all exploratory wells is the fraction of exploration wells that successfully discover economic oil or natural gas. This fraction is also called the discovery efficiency and is discussed in Section C.2. The number of platforms per discovery well is described in Section C.3. Section C.4 describes the methodology used to scale the lease costs by the ratio of expected production for the various model projects to the production of a typical project for the region.

C.1 AVERAGE LEASE COST PER TRACT

Lease sales have been held annually for OCS tracts in the Gulf of Mexico for many years. The most recent lease sales for the Atlantic, Pacific and Alaska were held in 1983, 1984 and 1984 respectively. To estimate 1986 lease prices for the Gulf of Mexico, we use the average cost per tract from the 1986 lease sale; see Table C-1. The Gulf of Mexico is a well-studied mature producing region. Prices in the area will rise and fall according to market prices. If lower prices are being paid for tracts in the Gulf of Mexico, lower prices are assumed to be paid for tracts in other regions.

To estimate lease prices for other regions, we use the ratio of 1986/1983 prices and 1986/1984 prices for the Gulf of Mexico (see Table C-1). The price per acre in the most recent lease sale is multiplied by the appropriate ratio to obtain an estimated 1986 cost per acre for that region. The cost per acre is multiplied by the average tract size in the most recent year to arrive at the estimated price per tract. For example, the most recent lease sale in the

TABLE C-1
GULF OF MEXICO LEASE PRICES*

Year	Region	Number of Tracts Offered	Number of Tracts Leased	Acreage Leased	Bonus	Average Tract Size (ac)	Average Cost per Tract ($)	Average Cost per Acre ($)	1986 Price Factor
1983	MAFLA	125	11	58,117	$37,570,900	5283	$3,415,536	$646.47	
	Central	7,050	623	3,089,812	$3,367,606,134	4960	$5,405,467	$1,089.91	
	Western	5,848	406	2,246,005	$1,501,712,517	5532	$3,698,799	$668.61	
	TOTAL 1983	13,023	1,040	5,393,934	$4,906,889,551	5186	$4,718,163	$909.71	0.28
1984	Eastern	8,868	156	897,786	$310,586,261	5755	$1,990,938	$345.95	
	Central	6,502	453	2,278,129	$1,323,036,649	5029	$2,920,611	$580.76	
	Western	5,446	361	1,949,186	$844,850,488	5399	$2,340,306	$433.44	
	TOTAL 1984	20,816	970	5,125,101	$2,478,473,398	5284	$2,555,127	$483.60	0.53
1986	Central	5,837	101	504,807	$130,276,757	4998	$1,289,869	$258.07	
	Western	4,887	41	229,612	$56,817,990	5600	$1,385,805	$247.45	
	Total	10,724	142	734,419	187,094,747	5172	$1,317,569	$254.75	1.00

Note: Current dollars.
Source: MMS, 1986a; MMS, 1987a.
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Pacific was held in 1984 (see Table C-2). The cost per acre in 1984 ($543.19) is multiplied by the 1986/1984 ratio of the Gulf of Mexico prices (0.53) to estimate a cost per acre of $286.15 in 1986. The average tract size in 1984 was 4,972 acres. The estimated average lease price in 1986 is 4,972 x $286.15 or $1,422,814.

The same methodology was used for the Atlantic region using 1983 data; see Table C-3. The projected tract price in 1986 dollars is $475,320.

The information for Alaska is presented in Table C-4. The 1984 prices were used to estimate 1986 prices. For Alaska, there is also information on sales in State waters and the prices are far lower than for the Federal regions. The 1986 State lease prices are used for the Cook Inlet projects while the estimated 1986 Federal lease prices are used for the Arctic projects.

C.2 DISCOVERY EFFICIENCY

Discovery efficiency is a parameter representing the fraction of exploration wells that successfully discover economic petroleum reserves. For example, if 5 wells are drilled in a basin, and one is successful, the discovery efficiency is 1/5 or 0.20. The inverse of the discovery efficiency is the number of exploratory wells that must be drilled to obtain a single successful well.

For this report, we choose to calculate discovery efficiencies based on historical data, using all exploratory wells drilled as of January 1, 1985 (API 1988, Section XI, Table 7). Discovery efficiencies may be calculated on a year-by-year basis, but since the number of offshore wells drilled in any given year is small, we prefer to use the all-time data. This information is presented in Table C-5. Note the effects of rounding: for the Pacific and Gulf of Mexico, the discovery efficiency is 0.14, rounded up from the more precise estimate of 0.135. The number of exploratory wells per discovery well (7.41) is the inverse of the more precise figure (0.135) rather than of the rounded figure (0.14).

TABLE C-2

PACIFIC LEASE PRICES*

Year	Region	Number of Tracts Offered	Number of Tracts Leased	Acreage Leased	Bonus	Average		
						Tract Size (ac)	Cost per Tract ($)	Cost per Acre ($)
1983	Southern	137	8	43,801	$16,022,336	5475	$2,002,792	$365.80
1984	Southern	657	23	114,363	$62,121,252	4972	$2,700,924	$543.19
1986	Projected					4972	$1,422,814	$286.15

Notes: Current dollars.
Projected price obtained by multiplying 1984 price by ratio of 1986/1984 prices in the Gulf of Mexico; see Table C-1.

Source: MMS, 1987a.

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TABLE C-3
ATLANTIC LEASE PRICES*

Year	Region	Number of Tracts Offered	Number of Tracts Leased	Acreage Leased	Bonus	Average Tract Size (ac)	Average Cost per Tract ($)	Average Cost per Acre ($)
1983	Middle	4,050	37	210,648	$68,410,240	5693	$1,848,925	$324.76
	South	3,582	11	62,625	$13,062,040	5693	$1,187,458	$208.58
	TOTAL 1983	7,632	48	273,273	$81,472,280	5693	$1,697,339	$298.14
1986	Projected *					5693	$475,320	$83.49

Notes: Current dollars.
Projected price obtained by multiplying 1983 price by ratio of 1986/1983 prices in the Gulf of Mexico; see Table C-1.

Source: MMS, 1987a.

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TABLE C-4
ALASKA LEASE PRICES*

Year	Region	Number of Tracts Offered	Number of Tracts Leased	Acreage Leased	Bonus	Average Tract Size (ac)	Average Cost per Tract ($)	Average Cost per Acre ($)
Federal								
1983	Norton	418	59	335,898	$317,873,372	5693	$5,387,684	$946.34
	St. George	479	96	540,917	$426,458,830	5635	$4,442,279	$788.40
	TOTAL 1983	897	155	876,815	$744,332,202	5657	$4,802,143	$848.90
1984	Navarin	5,036	180	1,024,772	$624,491,331	5693	$3,469,396	$609.40
	Beaufort Sea	1,419	231	1,230,486	$871,964,327	5327	$3,774,737	$708.63
	TOTAL 1984	6,455	411	2,255,258	$1,496,455,658	5487	$3,641,011	$663.54
1986	Projected *					5487	$1,918,041	$349.55
State								
1986	Beaufort		6	25,488	$396,585	4248	$66,098	$15.56
	Cook Inlet		45	175,866	$380,823	3908	$8,463	$2.17
	TOTAL		51	201,354	$777,408	3948	$15,243	$3.86

Notes: Current dollars.
Projected price obtained by multiplying 1984 price by ratio of 1986/1984 prices in the Gulf of Mexico; see Table C-1.

Source: MMS, 1987a; Alaska, 1987.

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TABLE C-5
TOTAL EXPLORATORY OFFSHORE WELLS DRILLED TO JANUARY 1, 1985

Region	Oil	Gas	Dry	Total	Discovery Efficiency	Number of Exploratory Wells Per Discovery
Alaska	20	7	73	100	0.27	3.70
California	44	10	294	348	0.16	
Oregon	0	0	8	8	0.00	
Washington	0	0	6	6	0.00	
Federal Pacific	0	0	38	38	0.00	
TOTAL PACIFIC	44	10	346	400	0.14	7.41
Alabama	0	2	0	2	1.00	
Florida	0	0	24	24	0.00	
Louisiana	267	349	3999	4615	0.13	
Texas	45	273	1732	2050	0.16	
Federal-GOM	0	0	241	241	0.00	
TOTAL GULF OF MEXICO	312	624	5996	6932	0.14	7.41
ATLANTIC	0	0	36	36	0.00	na
GRAND TOTAL	376	641	6451	7468	0.14	7.34

Note: Well count includes wells in both Federal and State waters.
na = not applicable

Source: API 1988; MMS 1986b.

C.3 NUMBER OF PLATFORMS PER DISCOVERY WELL

The number of platforms per discovery well is a measure of the quantity of reserves identified by that well. In the economic model, the cost of all exploratory wells (successful and unsuccessful) is divided among the number of platforms that tap the discovered field.

The most recent year for which we have consistent data for the number of discovery wells and the number of platforms is 1984. As of 1 January 1985, there were 936 discovery wells in the Gulf of Mexico (see Table C-5). At the end of 1984, there were 3,155 platforms in Federal waters and an additional 901 in State waters (MMS 1986c). This results in a ratio of (3,155+901)/936, or 4.3 production platforms per discovery.

For the Pacific, older offshore discoveries are produced from onshore completions and from artificial islands; a historical analysis is unlikely to provide a valid ratio. Based on the number of platforms installed in existing identified fields (see Table A-1), a projected ratio of 2.0 platforms per discovery is used in this analysis.

For the Atlantic, no historical data exist. The 5-Year Leasing Plan for mid-1987 to mid-1992 utilizes one-platform scenarios for the Atlantic (MMS 1987b, Appendix K). A 1:1 ratio of platforms to discoveries is used here.

For Alaska, relatively few wells are projected to be drilled during the 1986-2000 period (see Section 4). Such a situation could occur if only one platform is drilled per discovery well and that assumption is used here.

C.4 RATIO OF EXPECTED PRODUCTION

Section C.1 derives the average lease cost for a project in various OCS regions. The average lease cost should be scaled upwards or downwards according to the size of the model project. For each region, a typical project is chosen. The lease prices for the other projects in the region are scaled upwards or downward depending whether the project is larger or smaller than the typical project. The number of producing wells in the project is used as a surrogate index to represent the expected value of reserves used by a company in formulating a bid. This assumes that if, for example, a tract results in a 58-well platform, the company had good reason to believe that a very large reservoir underlay the tract prior to bidding.

For the Gulf, a project with 4 producing wells is considered typical (i.e., the Gulf 4 project). As of October 1985, there were 1,563 platforms with 4 wells or less (see Table A-3) while there was a total of 3,155 platforms (all sizes) at the end of 1984 (MMS 1986c). A 4-well platform has a production ratio of 1.0 and the lease price is scaled accordingly.

For the Pacific, the 40-well platform with 33 producing wells is considered typical. The 70-well platform with 60 producing wells has a production ratio of 1.8. Only one project is envisioned for the Atlantic, so the production ratio must be 1.0.

Projects in Cook Inlet, Alaska, are already scaled according to expected production (20 producing wells for oil or oil/gas, and 10 producing wells for the gas-only project), so the production ratio is 1.0 for Cook Inlet projects. For the Arctic projects, 40 producing wells is considered typical, thereby giving the smaller Norton Basin project a production ratio of 0.7.

Table C-6 lists the model projects, number of producing wells, production ratios, average lease prices, number of exploratory wells per discovery wells, and the number of platforms per discovery. The right-hand column of Table C-6 is the model project lease price used in the economic analysis.

C.5 REFERENCES

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TABLE C-6
LEASE PRICES FOR MODEL PROJECTS

Region	Model Project	Number of Producing Wells	Production Ratio	Lease Price ($000)	Exploratory Wells/ Discovery Well	Platforms/ Discovery	Model Project Lease Price ($000)
Gulf	1	1	0.3	$1,318	7.41	4.3	$568
	4	4	1.0	$1,318	7.41	4.3	$2,271
	6	6	1.5	$1,318	7.41	4.3	$3,407
	12	10	2.5	$1,318	7.41	4.3	$5,678
	24	18	4.5	$1,318	7.41	4.3	$10,221
	40	32	8.0	$1,318	7.41	4.3	$18,170
	58	50	12.5	$1,318	7.41	4.3	$28,391
Pacific	16	14	0.4	$1,423	7.41	2.0	$2,236
	40	33	1.0	$1,423	7.41	2.0	$5,272
	70	60	1.8	$1,423	7.41	2.0	$9,585
Atlantic	24	20	1.0	$0.475	10.00	1.0	$5
Alaska	Cook Inlet	20	1.0	$15	3.70	1.0	$56
	Cook Inlet-gas	10	1.0	$15	3.70	1.0	$56
	Beaufort-gravel	40	1.0	$1,918	3.70	1.0	$7,097
	Beaufort-plat.	40	1.0	$1,918	3.70	1.0	$7,097
	Norton	28	0.7	$1,918	3.70	1.0	$4,968
	Navarin	40	1.0	$1,918	3.70	1.0	$7,097

Note: 1986 dollars.

Source: ERG estimates.

APPENDIX D

EXPLORATION COST ASSUMPTIONS

The exploration phase assumptions include geological and geophysical expenses, discovery efficiency, drilling costs, and the number of platforms built per successful exploration well. The data and methodology used to develop estimates for each of these parameters are discussed in separate sections below.

D.1 GEOPHYSICAL AND GEOLOGICAL COSTS

Before a decision is made to drill, the proposed site is subjected to a variety of geological and geophysical prospecting procedures. These may include seismic analysis of the particular site and a study to evaluate the geological structures with regard to known neighboring productive formations. These costs are modeled as a percentage of the lease bid. For offshore production in the lower 48 states, this percentage has ranged from 6.5 percent in 1980 to 16.3 percent in 1984 to 110.5 percent in 1986 (Commerce 1982, API 1986, API 1987a). Onshore and offshore components have not been separated for Alaska in the recent API surveys. For this region, geological and geophysical costs have ranged from 33 percent of lease bids in 1980 to 12.6 percent in 1984 to 107.7 percent in 1986 (Commerce 1986, API 1986, API 1987a). The 1986 values are used in this analysis.

D.2 DISCOVERY EFFICIENCY

A discovery efficiency is the fraction of wells drilled that are successful in locating economically recoverable deposits of oil and/or gas. This parameter has been discussed in Section C.2. The discovery efficiencies are repeated in Table D-1 for convenience.

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TABLE D-1
TOTAL EXPLORATORY OFFSHORE WELLS DRILLED TO JANUARY 1, 1985

Region	Oil	Gas	Dry	Total	Discovery Efficiency	Number of Exploratory Wells Per Discovery
Alaska	20	7	73	100	0.27	3.70
California	44	10	294	348	0.16	
Oregon	0	0	8	8	0.00	
Washington	0	0	6	6	0.00	
Federal Pacific	0	0	38	38	0.00	
TOTAL PACIFIC	44	10	346	400	0.14	7.41
Alabama	0	2	0	2	1.00	
Florida	0	0	24	24	0.00	
Louisiana	267	349	3999	4615	0.13	
Texas	45	273	1732	2050	0.16	
Federal-GOM	0	0	241	241	0.00	
TOTAL GULF OF MEXICO	312	624	5996	6932	0.14	7.41
ATLANTIC	0	0	46	46	0.00	na
GRAND TOTAL	376	641	6461	7478	0.14	7.35

Note: Well count includes wells in both Federal and State waters.
na = not applicable

Source: API 1988; MMS 1986a.

D.3 DRILLING COSTS

The drilling costs per well are based upon the data in the 1986 Joint Association Survey on Drilling Costs (API 1987b). The number of oil or gas wells, footage drilled, and costs for the different state and federal offshore regions are given in Table D-2. Regional summaries are given for the Gulf of Mexico, Pacific and Alaska. There were no offshore wells drilled in the Atlantic in 1986. The data in Table D-2 include exploratory, delineation, and development wells (Oshinski 1988).

Table D-3 summarizes average well depths and costs. What is apparent is that dry holes tend to have a higher cost per foot than productive wells, particularly in Alaska and the Pacific. These data highlight some of the distinctive features of offshore operations. Exploratory and delineation wells are drilled from mobile drilling rigs and this is more expensive than drilling development wells from a fixed platform. Exploratory and delineation wells are plugged and abandoned at the end of operations after all information is gathered. Even if economically recoverable deposits of petroleum are identified, exploratory wells are not turned into production wells. Dry hole costs, then, predominantly reflect exploratory well costs. There is some corruption by a small number of dry development wells. It is not possible to separate these effects from the available data, but the effects are presumed to be minor. On this basis, dry hole costs for each region are used as exploratory well costs.

Exploratory well costs must still be estimated for the Atlantic region. The most recent wells drilled in the Atlantic were drilled in 1984. The 1984 survey on drilling costs lists three dry exploratory wells in the Atlantic; see Table D-4 (API 1985). We update these values to 1986 costs by multiplying them by the 15 percent increase seen in cost/foot for all dry offshore wells from 1984 to 1986. Total well cost is obtained by multiplying the updated cost per foot by the average depth of the 1984 well.

D.4 NUMBER OF PLATFORMS PER DISCOVERY WELL

The cost of the lease and exploration efforts is shared by number the number of platforms built per discovery well. This number of platforms per discovery well is discussed in Section C.3. For convenience, the information is reproduced here:

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TABLE D-2
1986 WELL COST DATA - BY WELL TYPE

	Oil			Gas			Dry		
Region	Wells	Footage	Cost	Wells	Footage	Cost	Wells	Footage	Cost
Alaska	10	108,676	$36,457,731	1	7,721	$1,790,891	2	19,323	$20,232,190
California	47	323,667	$74,432,135	2	12,954	$9,342,182	0	0	$0
Louisiana	228	2,206,577	$604,890,041	122	1,323,456	$446,385,625	219	2,384,433	$721,363,323
Texas	7	58,765	$18,122,985	69	827,623	$402,712,576	59	641,928	$241,973,709
Fed-Alaska	0	0	$0	0	0	$0	3	26,605	$49,022,867
Fed - Gulf	34	393,808	$282,072,709	13	128,355	$81,014,100	70	861,091	$552,048,104
Fed-Pacific	7	47,436	$25,014,462	0	0	$0	5	35,316	$29,438,964
AK-TOTAL	10	108,676	$36,457,731	1	7,721	$1,790,891	5	45,928	$69,255,057
PAC-TOTAL	54	371,103	$99,446,597	2	12,954	$9,342,182	5	35,316	$29,438,964
GULF-TOTAL	269	2,659,150	$905,085,735	204	2,279,434	$930,112,301	348	3,887,452	$1,515,385,136
ALL OFFSHORE	333	3,138,929	$1,040,990,063	207	2,300,109	$941,245,374	358	3,968,696	$1,614,079,157

Note: Current dollars.
Source: API 1987b.

TABLE D-3 30-Nov-89

AVERAGE WELL DEPTHS AND COSTS - 1986 DATA

	Oil			Gas			Dry			Total		
Region	Depth (ft)	Cost per foot ($/ft)	Cost per well ($)	Depth (ft)	Cost per foot ($/ft)	Cost per well ($)	Depth (ft)	Cost per foot ($/ft)	Cost per well ($)	Depth (ft)	Cost per foot ($/ft)	Cost per well ($)
Alaska	10,868	$335.47	$3,645,773	7,721	$231.95	$1,790,891	9,662	$1,047.05	$10,116,095	10,440	$430.89	$4,498,524
California	6,887	$229.97	$1,583,662	6,477	$721.18	$4,671,091	ERR	ERR	ERR	6,870	$248.87	$1,709,680
Louisiana	9,678	$274.13	$2,653,026	10,848	$337.29	$3,658,899	10,888	$302.53	$3,293,896	10,394	$299.71	$3,115,359
Texas	8,395	$308.40	$2,588,998	11,995	$486.59	$5,836,414	10,880	$376.95	$4,101,249	11,321	$433.69	$4,909,698
Fed-Alaska	ERR	ERR	ERR	ERR	ERR	ERR	8,868	$1,842.62	$16,340,956	8,868	$1,842.62	$16,340,956
Fed - Gulf	11,583	$716.27	$8,296,256	9,873	$631.17	$6,231,854	12,301	$641.10	$7,886,401	11,823	$661.58	$7,821,666
Fed-Pacific	6,777	$527.33	$3,573,495	ERR	ERR	ERR	7,063	$833.59	$5,887,793	6,896	$658.03	$4,537,786
AK-TOTAL	10,868	$335.47	$3,645,773	7,721	$231.95	$1,790,891	9,186	$1,507.90	$13,851,011	10,145	$662.27	$6,718,980
PAC-TOTAL	6,872	$267.98	$1,841,604	6,477	$721.18	$4,671,091	7,063	$833.59	$5,887,793	6,875	$329.61	$2,266,029
GULF-TOTAL	9,885	$340.37	$3,364,631	11,174	$408.05	$4,559,374	11,171	$389.81	$4,354,555	10,750	$379.62	$4,081,100
ALL OFFSHORE	9,426	$331.64	$3,126,096	11,112	$409.22	$4,547,079	11,086	$406.70	$4,508,601	10,476	$382.27	$4,004,805

Notes: Current dollars.
ERR denotes no wells drilled in that category in 1986.

Source: API 1987b.

Atl_well.wk1 30-Nov-89

TABLE D-4
EXPLORATORY WELL COSTS FOR ATLANTIC REGION

Region	Year	Wells	Footage	Cost	Average Depth (ft)	Average Cost per Well ($)	Average Cost per Foot ($/ft)	Ratio of 1986/1984 Cost per Foot
Offshore-Dry	1984	1,421	14,259,153	$5,023,946,644	10,035	$3,535,501	$352.33	
	1986	358	3,968,696	$1,614,079,157	11,086	$4,508,601	$406.70	1.15
Atlantic-Dry	1984	3	45,371	$72,228,519	15,124	$24,076,173	$1,591.95	
	1986				15,124	$27,791,575	$1,837.62	

Notes: Current dollars.
1986 well costs for the Atlantic projected by multiplying 1984 cost per foot by ratio of 1986/1984 costs per foot for offshore wells

Source: API 1985; API 1987b.

- Alaska - one platform per discovery
- Atlantic - one platform per discovery
- Gulf - 4.3 platforms per discovery
- Pacific - 2 platforms per discovery.

D.5 REFERENCES

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API 1985. American Petroleum Institute, 1984 Joint Association Survey on Drilling Costs, Washington, DC, 1985.

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API 1987b. American Petroleum Institute, 1986 Joint Association Survey on Drilling Costs, Washington, DC, November 1987.

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APPENDIX E

DELINEATION PHASE ASSUMPTIONS

The delineation phase of offshore oil and gas reserves involves the collection of adequate geological and reservoir data to determine the size, shape, and physical characteristics of the discovered energy supply. This usually involves drilling one or more delineation wells. The two parameters of interest for this phase are: cost per delineation well, and number of delineation wells per project. Each parameter is discussed in a separate section below.

E.1 COST PER DELINEATION WELL

Delineation wells differ from exploration wells in that more geologic data are collected in the form of directional drilling and cores and logs. The well costs presented in the Joint Association Survey on drilling costs, however, are a composite of all wells - exploratory, delineation, and development (Oshinski 1988). For this study, we use the same cost for delineation wells as for exploration wells, that is, dry hole costs. The logic behind using dry hole costs is discussed in Section D.3. The regional delineation well costs are presented here for convenience:

- Atlantic - $27,791,575.
- Alaska - $13,851,011.
- Pacific - $5,887,793.
- Gulf of Mexico - $4,354,555.

E.2 NUMBER OF DELINEATION WELLS PER PROJECT

The OTA report on oil and gas technologies for the Arctic and deepwater assume that 5 delineation wells will be used except for the nearshore Gulf of Mexico where only 3 are drilled (OTA 1985, p. 118). Table E-1 summarizes information on the number of delineation wells planned or drilled for several projects. As may be seen from this data, the OTA estimates are too high. In

TABLE E-1
NUMBER OF DELINEATION WELLS FOR TYPICAL OFFSHORE PROJECTS

Region	Field	Block	Number of Delineation Wells	References
Alaska	Endicott (Sag River/ Duck Island)		3	OGJ 1984
	Seal Island		3-4	Ocean Industry 1986a
	Sandpiper		2	Ocean Industry 1986a
	Colville Delta		4	Ocean Industry 1986a
Pacific	Sockeye		3	PEI 1983
	Huesco		1	PEI 1983
Gulf of Mexico	High Island	A-487	1	Ocean Industry 1982
		A-476	1	Ocean Industry 1982
	Vermillion	76	1	Ocean Industry 1982
	S. Marsh Is.	236	1	Ocean Industry 1982
	Matagorda Is.	487	1	Ocean Industry 1986b
	Mustang Is.	739	2-3	Ocean Industry 1986b
	Green Canyon	21	2	Ocean Industry 1986b
		52	2-4	Ocean Industry 1986b
		60	2-3	Ocean Industry 1986b
	Viosca Knoll	862	1	Ocean Industry 1986b

addition to the data in Table E-1, it should be noted that some projects in the Gulf of Mexico proceed without delineation wells. For example, Standard Oil is seeking in-house design approval of a platform for development of a discovery on Ewing Bank block 826, without any mention of delineation wells (Ocean Industry, 1986b).

On the basis of this information, ERG proposes the following number of delineation wells per project:

- No delineation wells - Gulf 1 and Gulf 4.
- 1 delineation well - Gulf 6.
- 2 delineation wells - Gulf 12, Gulf 24, Gulf 40, Gulf 58, Atlantic 24, Pacific 16, Pacific 40, Pacific 70, Cook Inlet 24, and Cook Inlet 12.
- 3 delineation wells - Beaufort Sea gravel island, Beaufort Sea platform, Bering platform and Norton platform.

E.3 REFERENCES

Ocean Industry 1982. "Oil & Gas Wrapup," Ocean Industry, June 1982, pp. 113-119.

Ocean Industry 1986a. "Exploration and development continue in Beaufort Sea," Ocean Industry, October 1986, pp. 34-40.

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APPENDIX F

DEVELOPMENT PHASE ASSUMPTIONS

The development phase involves the construction and installation of production structures and the drilling of development wells. The parameters needed to define the development phase of the economic model are:

- Platform/gravel island cost
- Lease equipment cost (also known as deck equipment cost)
- Development well cost
- Number of development wells
- Number of wells installed each year.

Each of these parameters is discussed in a separate section below.

F.1 PLATFORM/GRAVEL ISLAND COST

The Joint Association Survey on drilling costs instructs the operator to report expenditures through the "Christmas tree," the assembly of valves, pipes and fittings used to control the flow of oil and gas from the casinghead. For our project, it is instructive to quote from the instructions for the survey:

> "Do not report the cost of lease equipment such as artificial lift equipment and downhole lift equipment, flow lines, flow tanks, separators, etc. that are required for production...
>
> For OFFSHORE WELLS, include costs on fixed platforms and islands. Where facilities serve more than one well, the costs should be allocated to each well on the basis of the operator's best current estimate of the ultimate number of wells that will use the facility. Also include cost expirations (depreciation and amortization) for company-owned mobile platforms, barges, and tenders."
>
> (API 1987a, Appendix B, p.1)

In other words, platform and island costs are included in the well costs used in this report. Lease equipment costs, however, are not included in the well costs and are estimated separately in Section F.2.

F.2 LEASE EQUIPMENT COSTS

For the offshore production in the Lower 48 States, the average cost of lease equipment is based on the 1986 Annual Survey of Oil and Gas Expenditures line entry for lease equipment (API 1987b, Table III). The 1986 expenditure for offshore lease equipment is $1,032 million. According to the JAS survey on drilling, 898 offshore wells were drilled in 1986; 885 of these were in the Lower 48 States. This results in an average of $1.166 million ($1,032/885) in lease equipment per offshore well. We are indebted to John Oshinski of API for pointing out this method of obtaining lease equipment costs (Oshinski 1988). To obtain the lease equipment costs for each project, we multiply $1.166 million by the number of producing wells in that project; see Table F-1.

A different procedure must be used for Alaska because the Survey does not differentiate between onshore and offshore costs for lease equipment (API 1987b). Several different sources of actual and estimated costs are used for the Alaska projects.

For the Cook Inlet projects, costs are based on the recently installed Steelhead platform. OGJ 1986 refers to a $200 million project. We use an estimate of $200 million for the lease equipment cost for the 48-wellslot platform. Using the same assumption as OTA 1985, that there are no economies of scale on development costs, lease equipment costs are estimated at $100 million for the 24-wellslot platform and $50 million for the 12-wellslot platform. This is approximately $5 million per producing well, or about four times as expensive as for projects in the Lower 48 States offshore region.

The development cost for the Beaufort Gravel Island is based on the figures available for the Endicott field. Offshore 1986 cites a $1.4 billion development cost. Ocean Industry 1987b mentions that the gravel project was completed ahead of schedule and $600 million under budget. This results in an estimate of $800 million to develop the Endicott field. The study by the Office of Technology considers platform and facilities to account for 65 to 70 percent of total development costs (OTA 1985, p. 118). Since estimates for drilling in the Endicott field will not be available until the 1987 JAS at the earliest, we follow the OTA methodology and use the midpoint, 67.5 percent, as the percentage of development costs not associated with drilling. This results in an estimated $540 million in lease equipment costs. Since the Endicott field has two islands, the estimated cost per island is $270 million, or about $6.75 million per producing well.

Equip.wk1

TABLE F-1
LEASE EQUIPMENT COSTS - GULF, PACIFIC AND ATLANTIC

Region	Project	Number of Producing Wells	Lease Equipment Costs ($MM 1986)
Gulf	1b	1	$1.166
	4	4	$4.664
	6	6	$6.996
	12	10	$11.660
	24	18	$20.988
	48	32	$37.312
	58	50	$58.300
Pacific	16	14	$16.324
	40	33	$38.478
	70	60	$69.960
Atlantic	24	20	$23.320

Source: ERG estimates.

The lease equipment costs for the Beaufort platform, Navarin platform and Norton platform are based on the information in OTA 1985. For the Arctic deepwater projects, only engineering estimates are available since there are no such existing projects. We begin with the OTA estimated development costs (Table F-2, righthand column), obtain the non-drilling development costs by multiplying by 67.5 percent, and divide by the number of platforms/islands in the scenario. The resultant 1984 costs are then deflated by 0.4 percent to 1986 costs based on the implicit price deflators for gross national product for producers' durable equipment (Economic Report 1987, Table B-3).

Table F-2 summarizes the cost estimates for the Alaska projects. Lease equipment costs range from $50 million in Cook Inlet to $524.4 million in the Navarin Basin. On a per-producing-well basis, lease equipment costs range from $5 million to $13.11 million, or 4 to 12 times the cost for offshore wells in the Lower 48 States. As a check on these figures, we divide the $1,039 million spent in 1986 for lease equipment (API 1987a) by the 257 wells drilled in Alaska in 1986 (API 1987b). This is approximately $4 million per well. If lease equipment costs are less for onshore wells in Alaska as they are in the Lower 48 States, then the estimate falls within the range projected for the analysis.

F.3 DEVELOPMENT WELL COSTS

Development well costs are based on the costs for productive wells (see Table F-3). These estimates must be adjusted upwards to account for dry development wells. The regional discovery efficiencies for offshore development wells are given in Table F-4. The composite cost for a development well is the cost of a productive development well plus the fraction of a dry development well. The equation used is:

```
Composite cost for a  =  Cost per development well +
development well         [Number of development wells per producing well - 1)
                         *(dry hole cost per foot) * depth of producing well
```

For an oil well in the Gulf of Mexico, the composite development well cost is $3,364,631 (+ .4 x $389.81 x 9,8885) or $4,905,866. Table F-5 summarizes development well costs for the Gulf of Mexico, Pacific and Alaska regions.

There have been no development wells drilled in the Atlantic. As discussed in Appendix D, exploratory well costs are higher than development

$_akcon.wk1

TABLE F-2
LEASE EQUIPMENT COSTS FOR ALASKA PROJECTS

Project	Development Cost ($MM 1984)	Non-drilling Development Cost ($MM 1984)	Number of Islands/ Platforms	Cost per Platform ($MM 1984)	Cost per Platform ($MM 1986)	Producing Wells per Platform	Cost per Well ($MM 1986)
Beaufort platform	3,162	2,134.4	7	$304.9	$303.7	40	$7.59
Navarin Basin	5,460	3,685.5	7	$526.5	$524.4	40	$13.11
Norton Basin	1,038	700.7	4	$175.2	$174.5	28	$6.23
Beaufort Gravel*	800	540.0	2	$270.0	$270.0	40	$6.75
Cook Inlet oil*		200.0	2	$100.0	$100.0	20	$5.00
Cook Inlet gas*		200.0	4	$50.0	$50.0	10	$5.00

Notes: * Costs are in 1986 dollars.

1984 prices deflated by 0.4% based on implicit price deflators for gross national product for producers' durable equipment.

Sources: OTA 1985; OGJ 1986; Offshore 1986; Economic Report 1987.

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AVERAGE WELL DEPTHS AND COSTS - 1986 DATA

Region	Oil			Gas			Dry			Total		
	Depth (ft)	Cost per foot ($/ft)	Cost per well ($)	Depth (ft)	Cost per foot ($/ft)	Cost per well ($)	Depth (ft)	Cost per foot ($/ft)	Cost per well ($)	Depth (ft)	Cost per foot ($/ft)	Cost pe well ($)
Alaska	10,868	$335.47	$3,645,773	7,721	$231.95	$1,790,891	9,662	$1,047.05	$10,116,095	10,440	$430.89	$4,498,524
California	6,887	$229.97	$1,583,662	6,477	$721.18	$4,671,091	ERR	ERR	ERR	6,870	$248.87	$1,709,680
Louisiana	9,678	$274.13	$2,653,026	10,848	$337.29	$3,658,899	10,888	$302.53	$3,293,896	10,394	$299.71	$3,115,359
Texas	8,395	$308.40	$2,588,998	11,995	$486.59	$5,836,414	10,880	$376.95	$4,101,249	11,321	$433.69	$4,909,698
Fed-Alaska	ERR	ERR	ERR	ERR	ERR	ERR	8,868	$1,842.62	$16,340,956	8,868	$1,842.62	$16,340,956
Fed - Gulf	11,583	$716.27	$8,296,256	9,873	$631.17	$6,231,854	12,301	$641.10	$7,886,401	11,823	$661.58	$7,821,666
Fed-Pacific	6,777	$527.33	$3,573,495	ERR	ERR	ERR	7,063	$833.59	$5,887,793	6,896	$658.03	$4,537,786
AK-TOTAL	10,868	$335.47	$3,645,773	7,721	$231.95	$1,790,891	9,186	$1,507.90	$13,851,011	10,145	$662.27	$6,718,980
PAC-TOTAL	6,872	$267.98	$1,841,604	6,477	$721.18	$4,671,091	7,063	$833.59	$5,887,793	6,875	$329.61	$2,266,029
GULF-TOTAL	9,885	$340.37	$3,364,631	11,174	$408.05	$4,559,374	11,171	$389.81	$4,354,555	10,750	$379.62	$4,081,100
ALL OFFSHORE	9,426	$331.64	$3,126,096	11,112	$409.22	$4,547,079	11,086	$406.70	$4,508,601	10,476	$382.27	$4,004,805

Notes: Current dollars.
ERR denotes no wells drilled in that category in 1986.

Source: API 1987b.

TABLE F-4
TOTAL DEVELOPMENT OFFSHORE WELLS DRILLED TO JANUARY 1, 1985

Region	Oil	Gas	Dry	Total	Discovery Efficiency	Number of Development Wells Per Producing Well
Alaska	259	13	32	304	0.89	1.12
California	3516	25	327	3868	0.92	1.09
Alabama	1	1	1	3	0.67	
Louisiana	8144	4283	4480	16907	0.74	
Texas	104	454	700	1258	0.44	
Federal-GOM	69	19	58	146	0.60	
TOTAL GULF OF MEXICO	8318	4757	5239	18314	0.71	1.40
ATLANTIC	0	0	0	0	0.00	na

Note: Well count includes wells in both Federal and State waters.
na = not applicable

Source: API, 1988.

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TABLE F-5
DEVELOPMENT WELL COST - 1986 DATA*

Region	Type of Production	Number of Development Wells Per Producing Well	Average Depth (ft)	Cost per foot ($/ft) Productive	Dry	Composite Cost per Development Well ($)
Gulf	oil, oil/gas	1.4	9,885	$340.37	$389.81	$4,905,866
	gas	1.4	11,174	$408.05	$389.81	$6,301,845
Pacific	oil, oil/gas	1.09	6,872	$267.98	$833.59	$2,357,117
	gas	1.09	6,477	$721.18	$833.59	$5,157,007
Alaska	oil, oil/gas	1.12	10,868	$335.47	$1,507.90	$5,612,431
	gas	1.12	7,721	$231.95	$1,507.90	$3,187,985
Atlantic	oil, oil/gas		see text for description			$7,225,810
	gas					

Note: Current dollars.
Source: ERG estimates, see Table D-2.

well costs because of the need to drill them from mobile rigs. It is not appropriate, then, to use Atlantic exploratory well costs as Atlantic development well costs. Atlantic dry hole costs are projected at $1,837.62/foot (see Table D-4). This is comparable to the 1986 dry hole cost of $1,842.63/foot seen for drilling in Federal waters off the Alaskan coast (Table D-4). We project Atlantic productive well costs based on the ratio of oil-to-dry well costs for Alaska since the environment would not be harsher in the Atlantic. In 1986, an average Alaskan oil well cost $3,645,773 or 26 percent of a dry hole. The projected Atlantic development well cost is 0.26 x $27,791,575 or $7,225,810.

F.4 NUMBER OF PRODUCTION WELLS PER PLATFORM

The number of production wells in use at an offshore platform will vary widely, depending on the success of drilling programs, the size of the reservoir, the need for injection programs to maintain production, and project economics. The MMS Platform Inspection System Complex list shows widely varying situations. For example, some mature 12-wellslot platforms have never produced from more than 3, 4, or 5 wellslots while others are producing from all 12. Based on the MMS data, the average platform in the Gulf of Mexico is producing from 3/4 to 5/6 of its wellslots. Model projects were defined to fall within these bounds.

F.5 RATE OF INSTALLATION OF DEVELOPMENT WELLS

ERG has used the drilling rate of 6 wells per year per drilling rig. For platforms with more than 12 wellslots, two drilling rigs are assumed. This means that small projects, such as the Gulf 4, are brought to peak production in their first year. Twelve well platforms are developed within 2 years while larger platforms, e.g., 40 to 60 wells, require a 3- to 5-year development period. The 1- to 5-year period corresponds well with the 1- to 4-year span seen under "most intense development and production" in the MMS EIS for the 5-year leasing program (MMS 1987, Table IV.A.1-1).

F.6 REFERENCES

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APPENDIX G

PRODUCTION/OPERATION PHASE ASSUMPTIONS

The production and operation phase of an offshore project encompasses the period of time from first oil or gas production until shutoff of all wells. Parameters required to define this phase include:

- Peak production rate.
- Production decline rate.
- Time at peak production.
- Annual operation and maintenance costs.

Each parameter is discussed in its own section below.

G.1 PEAK PRODUCTION RATES

Well performance is a complex function of the thickness of the oil zone, geometry of the zone, effective permeability of the zone to oil, effective drainage radius of the well, and other factors. It is not surprising, then, that peak production rates and production decline rates are two parameters for which it is difficult to obtain "typical values." In this study, we assume that peak production occurs in the first year of operation. Field data, where available, are used to estimate average initial production rates.

G.1.1 Gulf of Mexico

Recent environmental impact statements for OCS sales in the Gulf of Mexico use "typical production profiles" per well to back-calculate the number of wells required to develop the estimated resources in the sale. The key factor is the cumulative amount of oil and gas produced per well and this will vary depending upon the region considered. The typical production profile has production climbing for 5 years, remaining at peak production for 3 to 4 years and then declining at rates between 5 percent and 10 percent per year. Gas wells are assumed to peak a few years later than oil wells and then decline at rates between 5 percent and 15 percent per year (Crawford, 1988).

To use the information in the EIS in this analysis, we begin by looking at the cumulative production per well. This ranges from 470,000 bbl per well to 1,579,000 bbl per well. Gas production ranges from 5.3 BCF to 10 BCF (MMS, 1986, and MMS, 1987a). Oil wells typically have a 10- to 11-year lifetime, while gas wells have a typical lifetime of 13 to 15 years (Crawford, 1988).

The MMS "typical" well is a composite of an oil well and a gas well. There were 8,318 oil wells and 4,757 gas wells in the Gulf as of 1 January 1985 (see Table F-4). The number of projected wells is multiplied by 63.6 percent (8,313/13,075) to obtain the number of oil wells. The remaining wells are assumed to be gas wells (see Table G-1, columns 3 and 4). Total cumulative oil production is divided by the estimated number of wells to calculate the cumulative production per oil well. The same procedure is followed to obtain the cumulative production per gas well.

Exponential decline rates are calculated for an oil well using 2 years at peak production, 10-year lifetime, an annual decline rate of 15 percent, and setting the cumulative production to the minimum and maximum cumulative production per oil well (740,384 and 2,481,937 bbl; see Table G-1). Initial production rates are back-calculated to match the production profile. The initial production rates for oil wells in the Gulf range from 330 bopd to 1,110 bopd. We use a value of 500 bopd to allow for the production of lease condensate by gas wells. In 1985, the Gulf of Mexico OCS region produced 321,509,934 bbl of oil and 537,402 MMcf for an average of 1.671 Mcf gas produced for every barrel of oil (MMS, 1987b; DOE 1986, Table 3). For an initial production rate of 500 bopd, there would be an associated 835 Mcf of gas production.

The same methodology is used to fit an exponential decline function to gas production. The production assumptions are a 20-year lifetime, a 15 percent annual decline rate, and four years at peak production. Cumulative production per well ranges from 14,483,944 Mcf to 27,485,810 Mcf (see Table G-1). Back-calculated initial production rates range from 4,000 Mcf/day to 8,000 Mcf/day. We use a value of 4,000 Mcf/day to allow for the production of casinghead gas by oil wells.

TABLE G-1
CUMULATIVE PRODUCTION PER WELL - GULF OF MEXICO ASSUMPTIONS

OCS Lease Sale	GOM Region	Number of Wells	Estimated Number of Oil Wells	Estimated Number of Gas Wells	Total Cumulative Production Oil (MMbbls)	Total Cumulative Production Gas (Bcf)	Cumulative Production Per Well Oil (bbls)	Cumulative Production Per Well Gas (Mcf)
110	Central	408	260	148	260	2,150	1,001,696	14,483,944
112	Western	276	176	100	130	1,870	740,384	18,622,632
113	Central	345	219	126	220	1,840	1,002,366	14,659,099
		630	401	229	400	3,870	998,027	16,884,141
115	Western	230	146	84	110	1,610	751,775	19,240,067
		426	271	155	220	2,870	811,775	18,517,436
116	Eastern	19	12	7	30	180	2,481,935	26,039,189
		76	48	28	120	760	2,481,935	27,485,810

Source: MMS 1986; MMS 1987a.

G.1.2 Pacific

The California Department of Conservation maintains records of oil and gas production in Federal and State waters. W. Guerard (1988) supplied peak production rates per well for fields that started from 1980 and after; see Table G-2. The peak production rates range from 286 bopd in the Santa Clara field to 2,840 bopd in the Hondo field. We use a value of 900 bopd in our model project. To estimate the amount of associated casinghead gas, we use the 1986 gas-to-oil ratio for offshore California wells; see Table G-3. The average ratio is 531 ft^3/bbl, so the model project would have a peak production of 900 bopd with 478 Mcf/day. An initial production rate of 5,000 Mcf/day is used for the gas-only project. This is lower than the first-year production from the Pitas Point field, but we also assume a longer period at peak production (see below).

G.1.3 Alaska

The Alaska Oil and Gas Conservation Commission supplied first-year production data for wells in Cook Inlet and the Beaufort Sea (Johnson, 1988). Engineering studies form the basis for the estimates for the Norton and Navarin Basin platforms.

Cook Inlet

Table G-4 calculates the average daily first-year production for 27 wells on platforms in Cook Inlet. The production ranges from 19 bopd to 7,004 bopd. ERG uses a value of 1,960 bopd in this analysis. Associated casinghead gas ranges from 7 Mcf/day to 2,256 Mcf/day. A value of 900 Mcf/day is used for the oil with casinghead gas projects in Cook Inlet.

Arctic Alaska

The Endicott field in the Beaufort Sea began production in late 1987. There are 16 wells that began production in October. Table G-5 summarizes the November and December production from those wells, i.e., the first full two months of production. Production is likely to drop from the impressive ca_prod.wk1 30-Nov-89

TABLE G-2
PEAK PRODUCTION RATES - CALIFORNIA

Field	Year of Peak Production	Peak Production bopd or Mcf/day
OIL PRODUCTION		
Beta	1981	535
Hondo	1981	2,840
Hueneme	1982	1,074
Santa Clara	1980	286
Average oil		1,184
GAS PRODUCTION		
Pitas Pt.	1985	11,185

Source: Guerard 1988.

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TABLE G-3
1986 GAS TO OIL RATIOS - CALIFORNIA

Region	Field or Area	1986 Oil and Condensate (bbl)	1986 Associated Gas (Mcf)	Gas to Oil Ratio (cf/bbl)
State	District 1	30,238,026	7,404,239	245
	District 2	1,333,390	3,087,795	2316
	District 3	3,061,615	2,419,052	790
Federal	Beta	7,040,207	2,444,898	347
	Carpinteria	1,978,018	1,524,822	771
	Dos Cuadras	5,063,795	2,557,080	505
	Hondo	11,100,847	10,370,192	934
	Hueneme	644,002	178,251	277
	Santa Clara	2,893,559	3,635,212	1256
TOTAL		63,353,459	33,621,541	531

Source: California 1987.

cook.wk1

TABLE G-4
AVERAGE FIRST-YEAR PRODUCTION FOR OIL WELLS IN COOK INLET, ALASKA

Platform	Completion Date			Year Production		Average Daily Production	
	Year	Mon	Day	Oil (bbl)	Gas (Mcf)	Oil (bbl)	Gas (Mcf)
Dolly Varden	68	3	5	1,013,373	298,105	3,367	990
	68	3	27	939,231	269,847	3,366	967
	68	4	19	1,311,355	367,279	5,122	1,435
	68	5	5	1,156,454	319,006	4,819	1,329
	68	5	21	281,638	85,455	1,257	381
	68	7	26	454,628	126,515	2,877	801
	68	7	3	665,112	171,993	3,675	950
	68	8	30	3,585	891	29	7
	68	10	14	31,288	8,658	401	111
	68	10	7	158,005	40,598	1,859	478
Grayling	68	1	1	1,421,897	391,143	3,896	1,072
	68	1	1	989,160	261,991	2,710	718
	68	2	19	1,323,508	394,258	4,188	1,248
	68	1	1	1,955,376	586,373	5,357	1,607
	68	4	2	541,645	124,537	1,984	456
	68	3	1	1,385,189	364,644	4,542	1,196
	68	8	23	374,595	116,415	2,882	896
	68	4	21	839,892	205,396	3,307	809
	68	5	28	4,227	0	19	0
	68	7	3	631,633	191,365	3,490	1,057
	68	12	5	56,108	13,981	2,158	538
King Salmon	68	2	15	1,686,065	474,326	5,269	1,482
	68	1	4	1,180,773	326,314	3,262	901
	68	11	27	99,971	24,366	2,940	717
	68	3	23	989,789	280,947	3,497	993
	68	5	22	971,676	257,253	4,357	1,154
	68	7	2	1,274,686	410,560	7,004	2,256

Source: Johnson, 1988.

TABLE G-5
INITIAL PRODUCTION FROM ENDICOTT FIELD, BEAUFORT SEA, ALASKA

Monthly Production							
Nov		Dec		Total			
Oil (bbl)	Gas (Mcf)	Oil (bbl)	Gas (Mcf)	Oil (bbl)	Gas (Mcf)	Average bopd	Average Mcf per day
238,603	193,044	185,341	135,456	423,944	328,500	6,950	5,385
269,964	223,977	168,940	140,306	438,904	364,283	7,195	5,972
210,326	174,992	12,612	9,771	222,938	184,763	3,655	3,029
125,502	98,358	48,223	30,082	173,725	128,440	2,848	2,106
164,240	118,966	198,145	140,770	362,385	259,736	5,941	4,258
243,696	202,388	181,826	143,815	425,522	346,203	6,976	5,675
230,273	230,547	142,490	153,769	372,763	384,316	6,111	6,300
245,612	202,071	223,189	176,437	468,801	378,508	7,685	6,205
162,298	135,626	215,708	178,112	378,006	313,738	6,197	5,143
117,291	98,165	206,092	153,383	323,383	251,548	5,301	4,124
138,905	105,438	206,282	144,965	345,187	250,403	5,659	4,105
232,460	182,227	209,881	156,141	442,341	338,368	7,251	5,547
243,017	201,925	217,055	173,498	460,072	375,423	7,542	6,154
235,009	318,449	208,137	350,650	443,146	669,099	7,265	10,969
168,092	244,519	115,670	233,215	283,762	477,734	4,652	7,832
48,265	38,415	30,890	24,438	79,155	62,853	1,298	1,030
AVERAGE				352,752	319,620	5,783	5,240

Source: Johnson, 1988.

average of 5,783 bopd, even within the first year, but it is apparent that Endicott will be an enormous producer like neighboring Prudhoe Bay.

Table G-6 lists the various engineering estimates for oil production in the Arctic. These range from 1,570 bopd in the Norton Basin to 4,000 bopd in the Beaufort Sea, Navarin Basin and St. George Basin. We use an estimate of 1,960 bopd for the oil production scenario in Arctic Alaska. There is no infrastructure for gas transport, so no oil/gas or gas-only scenarios are considered for the Arctic regions.

G.1.4 Atlantic

No discoveries have yet been announced in the Atlantic on which to base oil flow rates. The most recent EIS for the Atlantic Region is for OCS Sale 111 (MMS, 1985e). Like the Gulf of Mexico studies, a "typical production profile" is used to determine the number of development wells. Cumulative lifetime oil and gas production ranges from 3.4 to 4.5 million barrels and 66.7 to 74.1 Bcf. Decline rates appear to be in the order of 9 to 11 percent per year. Assuming a 20-year production life and an annual decline rate of 10 percent, initial oil production ranges from 1,100 to 1,500 bopd. A conservative estimate of 1,000 bopd is used in this analysis. Associated casinghead gas is assumed to be produced at a rate of 1 MMcf per barrel of oil, based on USGS estimates of recoverable reserves (USGS, 1981).

The estimated peak gas production rates range in the EIS from 21 to 23 MMcf per day. This value appears unrealistically high in view of the dry holes of Georges Bank and Baltimore Canyon. A value of 7.5 MMcf/day/well is used for the Atlantic model projects based on the assumption that geologic formations conducive to the presence of large productive gas fields occur off the Atlantic coast.

Table G-7 summarizes the model assumptions for peak production rates.

G.2 PRODUCTION DECLINE RATE

The pattern of decline in a well's productivity can vary greatly due to many factors (see Section G.1). ERG models production decline as an exponential function, i.e., a constant percentage of the remaining reserves produced in any given year. A general rule of thumb is that peak production

TABLE G-6

ENGINEERING ESTIMATE OF PEAK PRODUCTION RATES - ALASKA

DATA SOURCE	REGION	PEAK PRODUCTION RATE OIL BOPD	GAS MMCF/DAY	SOURCE
EIS	St. George Basin	4,000	26.3	MMS 1985a
	N. Aleutian Basin	3,500	26.6	MMS 1985b
	Norton Basin	1,570	10.3	MMS 1985c
Scenario Studies	Norton Basin	3,000-4,000	--	MMS 1985d
	Beaufort Sea	4,000	--	OTA 1985
	Norton Basin	2,000	--	OTA 1985
	Navarin Basin	4,000	--	OTA 1985

Source: As noted.

TABLE G-7

PEAK OFFSHORE PER-WELL PRODUCTION RATES

REGION	PROJECT	OIL ONLY BOPD	OIL AND GAS BOPD	OIL AND GAS MCF/DAY	GAS-ONLY MCF/DAY
Gulf	1	500	500	835	4,000
	4	500	500	835	4,000
	6	500	500	835	4,000
	12	500	500	835	4,000
	24	500	500	835	4,000
	40	500	500	835	4,000
	58	500	500	835	4,000
Pacific	16	900	900	478	5,000
	40	900	900	478	--
	70	900	900	478	--
Alaska[a]					
Cook Inlet	12	--	--	--	15,000
	24	1,960	1,960	900	--
Beaufort Sea - Gravel	48	1,960	--	--	--
Beaufort Sea - Platform	48	1,960	--	--	
Norton	34	1,960	--	--	
Navarin	48	1,960	--	--	
Atlantic	24	1,000	1,000	7,500	

Source: ERG estimates.

[a]There is no infrastructure to transport produced gas from the Arctic scenarios.

represents 10 to 15 percent of total reserves for the first 2 years and then declines approximately 15 percent per year (Muskat, 1949: North, 1985). The decline rate for the Pacific is higher. Decline rate assumptions are summarized in Table G-8.

G.3 YEARS AT PEAK PRODUCTION

The length of time each well will remain at peak production depends upon the rate of reservoir pressure decline, as well as other factors. All oil and oil/gas projects are assumed to remain at peak production for 2 years.

Gas projects in the Gulf and Pacific are assumed to remain at peak production for 4 years (Crawford, 1988). For Alaska, gas projects are assumed to remain at peak production for 16 years. Figure G-1 shows the production history of the North Cook Inlet gas field from 1969 through 1984 to support this assumption. There are no data for the Atlantic and an 8-year value was chosen for years at peak gas production.

G.4 OPERATION AND MAINTENANCE COSTS (O&M)

The annual 1986 costs of operating and maintaining an offshore platform are taken from DOE 1987. This survey includes O&M costs for a 12-wellslot platform in 100 and 300 feet of water as well as an 18-wellslot platform in 100, 300, and 600 feet of water (Table G-9).

A breakdown of the cost for a 12-wellslot platform in 100 feet of water is given in Table G-10. The platform is assumed to be staffed 24 hours a day with one crew. A crew is 12 people working 12 hours on and 12 hours off, so six people are working at any given time. In the next cost subcategory, equipment and administration, the term "surface equipment" refers to production equipment, flow control valves, dehydrators/line heaters (for gas operation) located on the platform surface. The third cost subcategory is workover costs. For a 12-wellslot platform, it is assumed that the workover rig takes one day to travel to the platforms, two days to set up, nine days to workover three wells, two days to tear down the equipment, and one day to move off. In other words, six of the fifteen days are for transit, set-up, and break-down; costs that would be borne even if working over only one well.

TABLE G-8

PRODUCTION DECLINE RATES

		PRODUCTION DECLINE RATES (%)	
REGION	PROJECT	OIL-ONLY OIL/GAS	GAS-ONLY
Gulf	1	15	15
	4	15	15
	6	15	15
	12	15	15
	24	15	15
	40	15	15
	58	15	15
Pacific	16	33	22
	40	33	--
	70	33	--
Alaska	Cook Inlet	10	15
	Beaufort Sea - Gravel	10	--
	Beaufort Sea - Platform	10	--
	Norton Basin	10	--
	Navarin Basin	10	--
Atlantic	24	15	15

-- = Not applicable.

Source: ERG estimates.

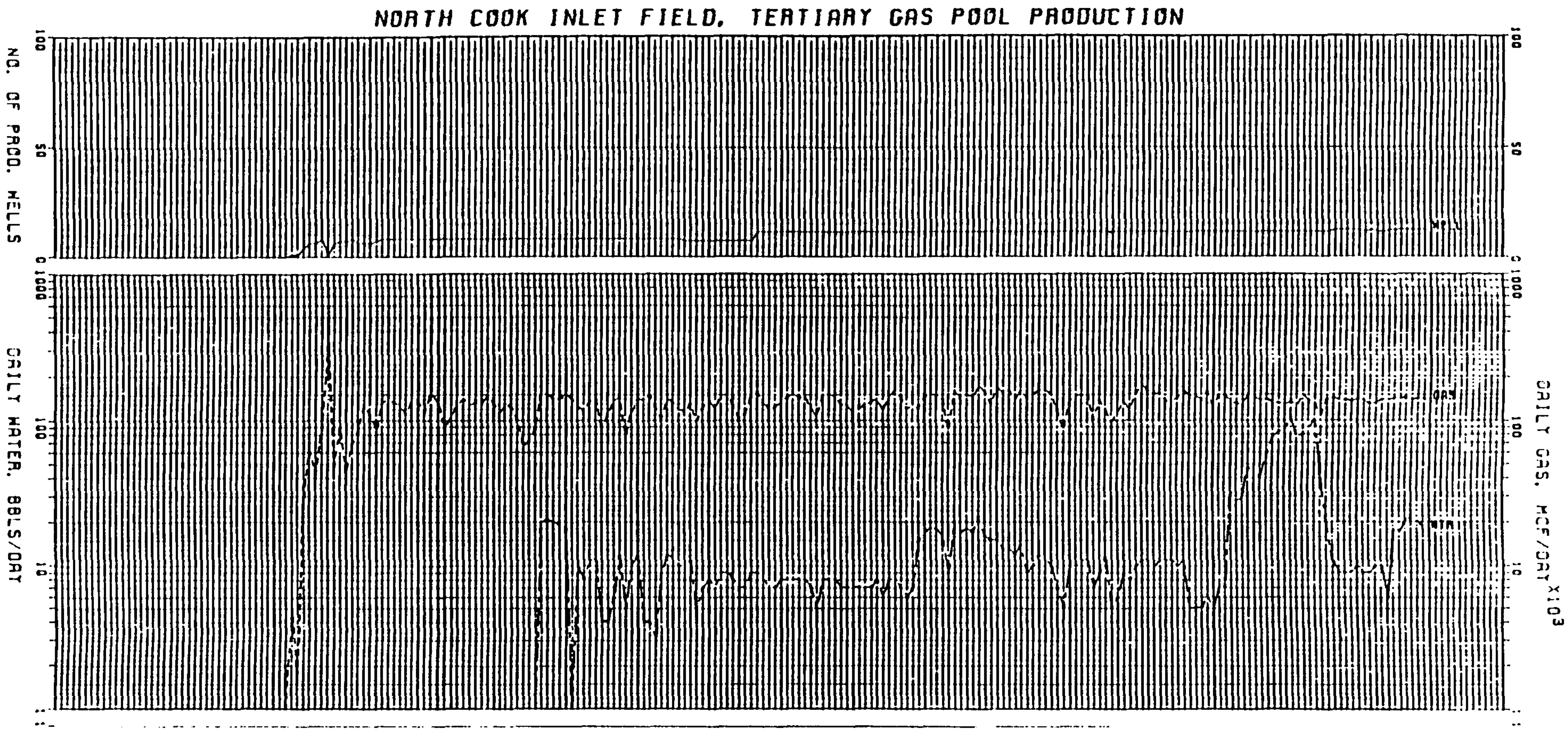

Figure G-1. North Cook Inlet Field, Alaska: gas production.

Source: Alaska 1984.

TABLE G-9
1986 OPERATION AND MAINTENANCE COSTS FOR GULF OF MEXICO PLATFORMS

Wellslots	Water Depth (ft)	Cost (1986 $)
12	100	$2,366,500
12	300	$2,482,300
18	100	$2,833,400
18	300	$2,963,100
18	600	$3,268,100

Source: DOE 1987.

O&M_gulf.wk1

TABLE G-10
ANNUAL OPERATING COSTS - 12-SLOT PLATFORM IN GULF OF MEXICO
100 FT WATER DEPTH (1986$)

Component	Component Cost ($)	Subcategory Cost ($)	Model Projects		
			Gulf 1	Gulf 4	Gulf 6
Labor Subcategory		$1,265,200	$770	$140,578	$210,867
Labor	$528,900				
Supervision	$79,300				
Payroll Overhead	$211,600				
Food Expense	$55,200				
Labor Transportation	$374,700				
Communications	$15,500				
Equipment & Administrative Subcategory		$605,900	$50,492	$201,967	$302,950
Surface equipment	$84,600				
Operating Supplies	$16,900				
Administrative	$252,200				
Insurance	$252,200				
Workover Subcategory					
Workover	$495,400	$495,400	$148,620	$346,780	$396,320
SUBTOTAL COSTS	$2,366,500	$2,366,500	$199,882	$689,324	$910,137
Costs for operation of remote production platform			$172,331		
TOTAL COSTS	$2,366,500	$2,366,500	$372,213	$689,324	$910,137

Source: DOE 1987.

These assumptions make it inappropriate to use the data from the 12-wellslot and 18-wellslot platforms, perform a regression analysis, and extrapolate back to the smaller Gulf projects. The DOE/EIA data for each of the cost subcategories can be scaled to estimate the annual operating costs for the smaller Gulf projects.

Table G-11 summarizes the assumptions for the labor subcategory for the Gulf 1, Gulf 4, and Gulf 6 projects. The Gulf 1 is essentially untended; a crew of two inspect the structure 4 times a year. One day is assumed for each inspection. The Gulf 4 and the Gulf 6 platforms are assumed to have a crew of 4 and 6 people, respectively, that commute to the rig on a daily basis. The work day is assumed to be eight hours. The labor costs for these small projects are scaled from Gulf 12 costs as a percentage of labor hours. For example, the Gulf 4 requires 11,680 person-hours a year or 11.11 percent of hours required for the Gulf 12 platform. The labor costs for the Gulf 4 project are (11,680/105,120) x $1,265,200 or $140,578.

The equipment and administrative costs are scaled according to the number of wells on the project. For example, the costs for this subcategory for the Gulf 6 is $302,950 or one-half the costs for the Gulf 12 project.

Workover costs are also scaled. Gulf 1 projects are assumed to be worked over every two years. Each workover takes 9 days (6 for preparation and disassembly and three for the workover itself). The proportion of the workover cost borne each year is (9/2)/15 or 30 percent. The Gulf 4 and Gulf 6 projects are assumed to workover an average of one and a half wells and two wells per year, respectively. The cost proportions are (6 + 4.5)/15 or 70 percent and (6 + 6)/15 or 80 percent, respectively.

One last factor needs consideration. The Gulf 1a is assumed to have no production equipment and shares a production platform with three other single well structures. The O & M costs for the Gulf 1a therefore includes one-fourth of the annual operating costs for a Gulf 4 platform.

The DOE/EIA data can be used to estimate annual operating costs for the larger projects in the Gulf. To project O&M cost for the model projects, a regression analysis was fit to the data using the following equation.

$$\text{Cost} = a + b\,(\text{wellslots}) + c\,(\text{depth})$$

O&M_gulf.wk1

TABLE G-11
LABOR ASSUMPTIONS FOR SMALL GULF PROJECTS

Labor Component	DOE/EIA Study	Model Project Gulf 1	Gulf 4	Gulf 6
Hours per Day	24	8	8	8
Days per Year	365	4	365	365
People per Crew	12	2	4	6
Person-hours per Year	105,120	64	11,680	17,520
Fraction of DOE/EIA study	100%	0.06%	11.11%	16.67%

Source: DOE 1987; Funk 1989.

The values for a, b, and c are $1,286,123, $80,859, and $840, respectively. Table G-12 shows the estimated O&M costs for platforms in the Gulf of Mexico.

For the Pacific, Cook Inlet and Atlantic projects, we use the basic equation presented above and then adjust for regional differences (see Table G-13). The O&M costs for California onshore oil and gas operations are approximately 144 percent of onshore operations for Texas and Louisiana (see Table G-14). The regional multiplier for the Pacific is therefore 1.44. The same multiplier is used for the Atlantic region. For Cook Inlet scenarios, a multiplier of 1.6 is used (ERG 1985).

The information in OTA 1985 forms the basis for estimating the operating costs for Arctic Alaska scenarios; see Table G-15. The costs per scenario are divided among the number of platforms or islands and then deflated to 1986 values.

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TABLE G-12
OPERATING COSTS FOR GULF OF MEXICO PLATFORMS

Project	Number of Wellslots	Water Depth (ft)	Cost ($1986)
Gulf 1a	1	33	$372,213
Gulf 1b	1	33	$199,882
Gulf 4	4	33	$689,324
Gulf 6	6	33	$910,137
Gulf 12	12	66	$2,311,861
Gulf 24	24	100	$3,310,725
Gulf 40	40	200	$4,688,455
Gulf 58	58	590	$6,471,456

Source: ERG estimates.

gulf_o&m.wk1

TABLE G-13
OPERATING COSTS FOR PACIFIC, ATLANTIC, AND COOK INLET PLATFORMS

Project	Number of Wellslots	Water Depth (ft)	Cost ($1986)	Regional Cost Factor	Estimated Cost ($1986)
Pacific 16	16	300	$2,831,820	1.44	$4,077,821
Pacific 40	40	300	$4,772,439	1.44	$6,872,312
Pacific 70	70	1000	$7,786,100	1.44	$11,211,984
Atlantic 24	24	300	$3,478,693	1.44	$5,009,318
Cook Inlet 24	24	50	$3,268,733	1.60	$5,229,973
Cook Inlet 12	12	50	$2,298,424	1.60	$3,677,478

Source: ERG estimates.

TABLE G-14
RATIO OF 1986 OPERATION & MAINTENANCE COSTS - CALIFORNIA AND GULF COAST

Well Depth (ft)	Operation & Maintenance Cost - 10 Primary Oil Wells					California/ Gulf Coast Ratio
	California	Louisiana	West Texas	South Texas	Average Gulf	
2,000	$119,700	$117,600	$88,300	$98,500	$101,467	1.18
4,000	$162,400	$171,700	$102,200	$146,500	$140,133	1.16
8,000	$280,200	$203,000	$141,700	$175,100	$173,267	1.62
10,000	$403,700	$252,800	$188,900	$232,400	$224,700	1.80
Average Ratio						1.44

Source: DOE 1987.

ak_o&m.wk1

TABLE G-15
OPERATION AND MAINTENANCE COSTS FOR ALASKA PROJECTS

Project	Operation and Maintenance Cost ($MM 1984)	Number of Islands/ Platforms	Cost per Platform ($MM 1984)	Cost per Platform ($MM 1986)
Beaufort platform	$168.0	7	$24.0	$25.3
Navarin Basin	$132.0	7	$18.9	$19.9
Norton Basin	$72.0	4	$18.0	$19.0
Beaufort Gravel	$120.0	7	$17.1	$18.1

Note: 1984 prices inflated by 5.56% based on change in consumer price index.

Sources: OTA 1985; Economic Report 1988.

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APPENDIX H

PRODUCED WATER ASSUMPTIONS

Peak water production is used in determining the equipment required on the platform to comply with the proposed regulatory options. Average annual water production is used to estimate the annual operation and maintenance cost (O&M) for each platform. The capital (equipment) and O&M costs are factored into the economic model for each platform to calculate the annualized cost for each regulatory option. The total volume of produced water generated during the 1986-2000 time period is used to estimate the amount of pollutants removed by each regulatory option.

The capital and O&M costs are calculated by EPA, Industrial Technology Division on the basis of the produced water volumes presented in this appendix. These costs will be documented in the Development Document supporting the Offshore Oil and Gas regulation.

H.1 MODELING ASSUMPTIONS

Modeling assumptions differ depending upon whether a well produces oil or only gas. These assumptions are outlined in the sections below.

H.1.1 Projects with Oil Production

For projects that produce oil or oil with gas, water production is calculated as a function of <u>total liquid production</u>. In other words, the well is assumed to produce a constant volume of fluid during its lifetime, but the proportion of fluid that is water will increase as the well ages. To evaluate water production as a function of total liquid production, we need to estimate several parameters:

- Relationship of oil decline and water increase
- Functional form of oil production decline
- Decline rate of oil production
- Initial watercut (i.e., how much of the fluid is water at the time the well first produces)

Oil production is assumed to decline at an exponential rate. The rate of decline varies by region (see Appendix G for more details). As oil production declines, water production increases to maintain a constant volume. (Figure H-1 illustrates the oil and water production from a well with an initial production rate of 100 bbl/day for two years and a 15 percent exponential decline every year thereafter.)

Initial watercut data are available from Alaska for platforms in coastal waters and gravel islands in offshore waters (Table H-1). Initial watercut values range from 0.1 percent to 4.3 percent with a median value of 0.9 percent. We round this value upwards to 1 percent for Alaska and all other regions.

H.1.2 Projects with Gas-Only Production

There is generally little water produced with gas-only operations. Under these circumstances we estimate water production with a water:gas ratio. Water production for gas wells is assumed to be a function of gas production times a water:gas ratio. A constant water:gas ratio was used in the economic impact analysis of the disposal of **onshore** production wastes under Section 8002(m) of RCRA (ERG 1987).

An Appalachian basin survey is the only survey of which we are aware that investigates water production from gas wells (Flannery and Lannan 1987). The survey appears well designed and covers approximately 10 percent of existing Appalachian Basin wells, including 12,274 gas wells. Approximately 39 percent of the gas wells produce no water at all, even with gas production rates exceeding 60 Mcf/day. An additional 51 percent produce less than 10 barrels of water per month. Less than 1 percent produce in excess of 100 barrels of water a month. Averaging the survey data results in an estimated water:gas ratio of 17.2 bbl per MMcf.

For comparison, the water:gas ratio for offshore California gas wells can be calculated from the annual report of the oil and gas supervisor. Table H-2 shows the data for 1985, 1986, and 1987 (California 1986, California 1987, and California 1988). The ratio for the wells in state waters increases four-fold from 1985 to 1986. The 1986 water:gas ratio for gas wells in State waters is 16.2 bbl per MMcf, which is similar to the ratio from the Appalachian basin. The water:gas ratio for gas wells in State waters climbs another fourfold from

Figure H-1

Water : Oil Relationship

Exponential Oil Decline

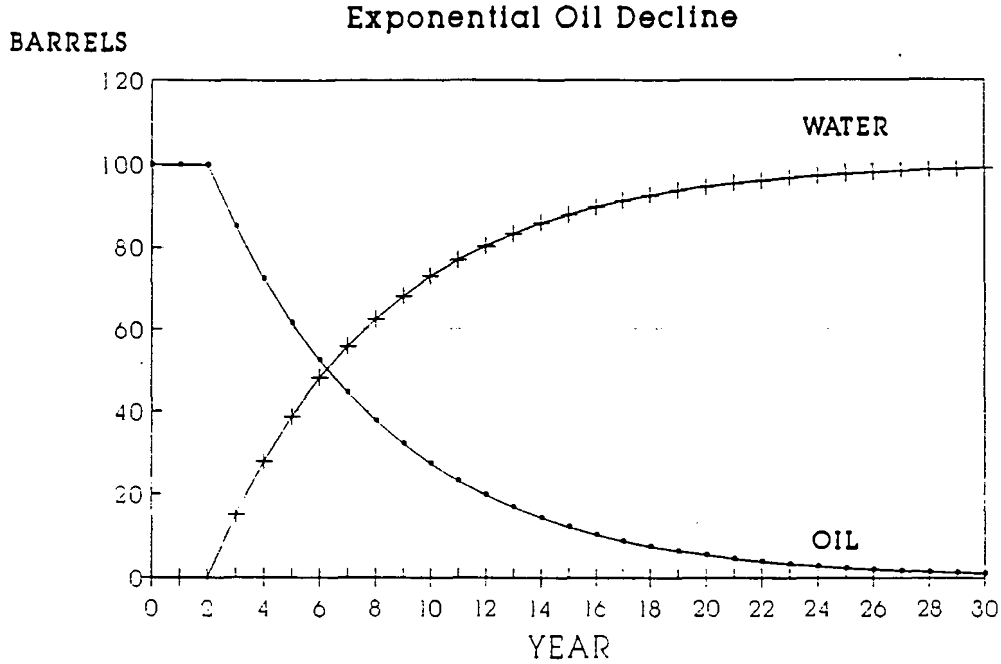

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TABLE H-1
INITIAL WATERCUT - ALASKA

Region	Field	Platform	Year Installed	Initial Production Data: Year	Number Of Wells	Oil (bbl)	Water (bbl)	Initial Watercut (%)
Cook Inlet*	Granite Point	Bruce	1966	1967	11	4,569,773	50,026	1.1%
		Granite Point	1966	1967	5	2,479,506	1,457	0.1%
	Trading Bay	Spark	1966	1967		**		
		TSA	1966	1967		**		
		Monopod	1966	1967	12	726,966	808	0.1%
	McArthur River	King Salmon	1967	1968	8	6,239,122	203,302	3.3%
		Grayling	1967	1968	13	9,523,640	49,338	0.5%
		Dolly Vardin	1967	1968	12	6,019,548	19,536	0.3%
		Steelhead	1987					
	Middle School Ground	Baker	1965	1966	5	686,140	5,623	0.8%
		A	1964	1966	11	2,249,359	41,487	1.8%
		C	1964	1968	12	4,603,781	39,780	0.9%
		Dillon	1965	1968	10	2,321,014	100,650	4.3%
Beaufort	Endicott	Island	1987	1987	29	8,795,758	171,363	1.9%

Notes: * Platforms in Cook Inlet are in the coastal subcategory.
** Only gas production listed, no associated water production.
Phillip's A platform, installed in 1968 in North Cook Inlet, is a gas-only platform.
No water production is listed for 1969.

Source: Individual well production reports provided by Elaine Johnson, Alaska Oil and Gas Commission, Anchorage, AK, February 1988.

h20_gas.wk1

TABLE H-2
OFFSHORE WATER:GAS RATIOS - CALIFORNIA

Year	Region	Number of Wells	Gross Gas Production (Mcf)	Water Production (bbl)	Water:Oil Ratio (bbl:MMcf)
1985	State	6	6,126,304	25,016	4.1
	Federal	15	31,227,299	177,724	5.7
	Combined	21	37,353,603	202,740	5.4
1986	State	6	5,341,798	86,542	16.2
	Federal	15	27,279,321	136,396	5.0
	Combined	21	32,621,119	222,938	6.8
1987	State	4	2,067,900	138,277	66.9
	Federal	18	23,424,998	150,075	6.4
	Combined	22	25,492,898	288,352	11.3

Source: California 1986, California 1987, and California 1988.

1986 to 1987 when it is 67 bbl per MMcf. Note also that by 1987, two of the six gas wells had stopped producing. For gas wells in Federal waters for 1985 through 1987 and for gas wells in State waters for 1985, the water:gas ratio ranges from 4.1 to 6.4 bbl per MMcf.

The North Cook Inlet field has the sole gas-only platform in Alaska. Although the field is in coastal waters, we use the data as indicative of the potential water production from gas-only operations in offshore southern Alaska. For the North Cook Inlet field, gas production is approximately 130 MMcf/day while water production is generally about 10 bbl/day with fluctuations as high as 100 bbl/day (see Figure H-2). This results in a water:gas ratio of 0.08 bbl per MMcf with fluctuations as high as 0.77 bbl per MMcf. In 1984, the North Cook Inlet field produced 46,981 MMcf of gas and 5,058 bbl of water for a water:gas ratio of 0.11 bbl per MMcf (Alaska 1984).

The monthly summaries of production for the Federal Gulf of Mexico list oil, condensate, gas, casinghead gas, and water. That is, no distinction is made between produced water from gas operations and produced water from oil and oil-with-gas operations. Discussions with MMS personnel resulted in the observation that, in general, little water is produced with gas-only operations, although there are exceptions (Lowenhaupt 1989).

From the California data in Table H-2 and the Alaska data in Figure H-2, we see that water production from gas operations can be extremely variable. The highest water:gas ratio seen in the offshore and onshore data is about 67 bbl of water per MMcf produced. But this high value appears in only a few wells that appear to be close to the end of their economic lifetime. The average value seen in the onshore Appalachian data - 17 bbl/MMcf - exceeds the water:gas ratios seen for the Alaska data, offshore Federal California gas wells, and offshore State California gas wells for two of the three years of data. The 17 bbl/MMcf is the water:gas ratio used in this analysis.

H.2 PEAK WATER PRODUCTION

H.2.1 Projects with Oil Production

Peak water production is the amount of water produced in the last year of the economic lifetime of the well. Table H-3 shows the sample calculations for the Gulf 24 model with 18 productive wells. Peak oil production occurs in

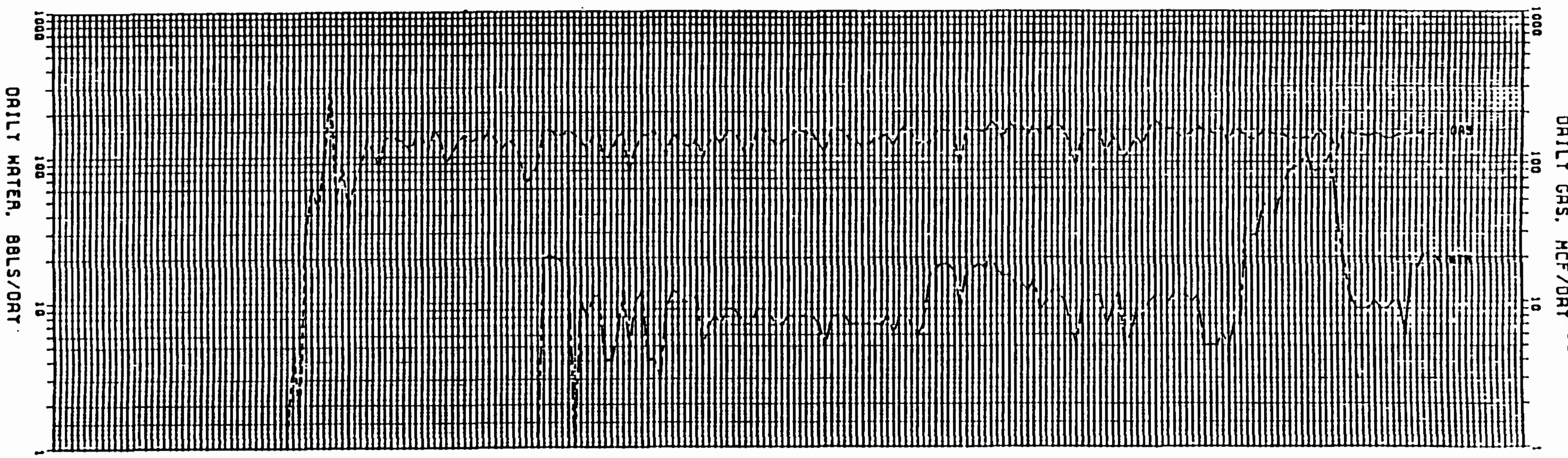

Figure H-2. Water and Gas Production from North Cook Inlet Field, Alaska

Source: Alaska 1984.

TABLE H-3
WATER PRODUCTION ESTIMATES - GULF OF MEXICO
GULF 24 MODEL

Year	Oil Production (bbl/d) Year 1	Year 2	Year 3	Year 4	Year 5	Total	Water Production (bbl/d)	Cumulative Water Production (bbl/d)	Average Annual Water Production (kbbl/yr)
1	6000					6000	60	60	22
2	6000	3000				9000	90	150	27
3	5100	3000	0			8100	990	1,140	139
4	4335	2550	0	0		6885	2205	3,345	305
5	3685	2168	0	0	0	5852	3238	6,583	481
6	3132	1842	0	0	0	4974	4116	10,698	651
7	2662	1566	0	0	0	4228	4862	15,560	811
8	2263	1331	0	0	0	3594	5496	21,056	961
9	1923	1131	0	0	0	3055	6035	27,091	1,099
10	1635	962	0	0	0	2597	6493	33,584	1,226
11	1390	817	0	0	0	2207	6883	40,467	1,343
12	1181	695	0	0	0	1876	7214	47,681	1,450
13	1004	591	0	0	0	1595	7495	55,177	1,549
14	853	502	0	0	0	1355	7735	62,911	1,640
15	725	427	0	0	0	1152	7938	70,849	1,724
16	617	363	0	0	0	979	8111	78,960	1,801
17	524	308	0	0	0	832	8258	87,217	1,873
18	446	262	0	0	0	708	8382	95,600	1,939
19	379	223	0	0	0	601	8489	104,088	2,000
20	322	189	0	0	0	511	8579	112,667	2,056
21	274	161	0	0	0	435	8655	121,322	2,109
22	233	137	0	0	0	369	8721	130,043	2,158
23	198	116	0	0	0	314	8776	138,819	2,203
24	168	99	0	0	0	267	8823	147,642	2,245
25	143	84	0	0	0	227	8863	156,505	2,285
26	121	71	0	0	0	193	8897	165,403	2,322
27	103	61	0	0	0	164	8926	174,329	2,357
28	88	52	0	0	0	139	8951	183,279	2,389
29	75	44	0	0	0	118	8972	192,251	2,420
30	63	37	0	0	0	101	8989	201,240	2,448

Notes:
500 bbl/day initial production per well
15% decline rate
1% initial watercut
18 producing wells.

the second year of operation at a rate of 9,000 bbl/day. With an initial watercut of 1 percent, total fluid production is 9,090 bbl/day. Water production is the difference between oil production and total fluid production. For example, in year 19, water production is 8,489 bbl/day (i.e., 9,090 bbl/day total fluid production minus 601 bbl/day oil production). Cumulative water production is 104,088 bbl/day in Year 19.

Peak water production, then, depends on the economic lifetime of the project. The same project will have different peak water production rates for BAT and NSPS evaluations because different oil prices are assumed in the BAT and NSPS analyses. Project lifetimes and peak water production rates are summarized in Table H-4.

H.2.2 Projects with Gas-Only Production

Peak water production for gas-only projects occurs at the time of peak gas production. There will be no difference in peak water production for gas-only projects depending upon whether the scenario studied is BAT or NSPS. Peak water production rates for all projects are given in Table H-4.

H.3 AVERAGE WATER PRODUCTION

H.3.1 Projects with Oil Production

Average water production for oil-only and oil-with-gas projects is the cumulative water production through the last economic year of production divided by the economic lifetime of the well. For example, for a Gulf 24 model with an economic lifetime of 20 years (see Table H-3), average annual water production is calculated as:

$$\frac{\text{Cumulative water production (bbl/day) * 365 days/yr}}{\text{Economic lifetime of model project}} \Big/ 1000 = \text{Average Annual Water Production (kbbl/yr)}$$

or,

$$\frac{112{,}667 * 365}{20} \Big/ 1000 = 2{,}056 \text{ kbbl/yr}$$

TABLE H-4
REVISED PEAK WATER PRODUCTION RATES - EXISTING AND PROJECTED STRUCTURES

Project Type	Region	Model	Economic Lifetime of Project (Years) Existing	Economic Lifetime of Project (Years) Projected	Peak Water Production Rate per Project (bbl/day) Existing	Peak Water Production Rate per Project (bbl/day) Projected
OIL ONLY	Gulf	1a	13	15	421	445
		1b	17	19	461	473
		4	18	20	1,871	1,913
		6	18	20	2,807	2,869
		12	16	18	4,500	4,653
		24	18	20	8,382	8,579
		40	20	22	15,162	15,439
		58	22	24	23,969	24,325
	Pacific	16	8	9	11,506	11,909
		40	9	10	27,272	28,171
		70	11	12	50,718	51,979
	Atlantic	24	**	21	**	19,224
	Cook Inlet*	24	**	30	**	37,449
	Beaufort Platform	48	**	28	**	73,405
	Beaufort Island	48	**	30	**	74,503
	Navarin Platform	48	**	30	**	74,503
	Norton Platform	34	**	27	**	51,169
OIL AND GAS	Gulf	1a	14	16	434	454
		1b	18	20	468	478
		4	19	21	1,894	1,929
		6	19	21	2,841	2,893
		12	17	19	4,582	4,712
		24	19	21	8,489	8,655
		40	21	23	15,312	15,547
		58	23	25	24,161	24,463
	Pacific	16	8	9	11,506	11,909
		40	9	10	27,272	28,171
		70	11	12	50,718	51,979
	Atlantic	24	**	21	**	19,224
	Cook Inlet*	24	**	30	**	37,449
GAS ONLY	Gulf	1a	14	16	68	68
		1b	18	20	68	68
		4	19	21	272	272
		6	20	21	408	408
		12	17	19	680	680
		24	19	21	1,224	1,224
	Pacific	16	11	13	1,190	1,190
	Atlantic	24	**	25	**	2,550
	Cook Inlet*	12	**	29	**	2,550

Notes: * Existing platforms in Cook Inlet are in the coastal subcategory.
** Produced water from gravel islands in the Beaufort Sea (i.e., the Endicott field) is reinjected per State requirement. There are no platforms currently producing in the Beaufort, Navarin, Norton or Atlantic areas. Economic impacts are evaluated for these projects and projects in the non-coastal region near Cook Inlet that may occur at some point in the future.

Source: ERG estimates.

Average water production by structure is listed in Table H-5.

This methodology is used for oil-only and oil-with-gas projects. Projects with associated gas production are not assumed to produce more water than projects that produce only oil. If gas production is coming from separate gas wells on a platform, this approach may overestimate water production since gas wells generally produce less water than oil wells. This may occur in existing structures but there is no information by which to adjust existing structure counts for this phenomenon. Projected structures are assumed to have associated gas production for oil-with-gas model projects and are unaffected by this assumption.

H.3.2 Projects with Gas-Only Production

For average water flow rates, regional average water:gas ratios are used where available. For California the ratio is 7 bbl water per MMcf (see Table H-2 for wells in Federal waters). The 7:1 ratio is also used for Gulf of Mexico and Atlantic projects. For Alaska, a 1:1 ratio is used based on the data from the North Cook Inlet field (see Section H.1.2; this value is rounded upwards to a 1:1 ratio). As for projects with oil production, average annual water production is calculated as the cumulative water production divided by the number of years of production. Because a water:gas ratio is used to calculate water production from gas projects, and gas production declines over the life of the well, average water production for longer-lived gas projects will be lower than for shorter-lived gas projects. Average water production by structure is listed in Table H-5.

H.4 TOTAL ANNUAL WATER PRODUCTION

Total amount of water produced is estimated in two steps. First, in order to obtain water production by model project, the number of each model project is multiplied by the average annual water production associated with each project. These project totals are then summed over all projects to obtain the grand total of water produced during the time period. Projects will be installed and come into production throughout the time period, but the amount of water produced by each project will be the average annual water flow.

TABLE H-5
REVISED AVERAGE ANNUAL WATER PRODUCTION RATES - EXISTING AND PROJECTED STRUCTURES

Project Type	Region	Model	Economic Lifetime of Project (Years) Existing	Projected	Average Annual Water Production Rate per Project (kbbl/yr) Existing	Projected
OIL ONLY	Gulf	1a	13	15	90	99
		1b	17	19	107	114
		4	18	20	443	469
		6	18	20	665	703
		12	16	18	994	1,071
		24	18	20	1,939	2,056
		40	20	22	3,505	3,696
		58	22	24	5,486	5,767
	Pacific	16	8	9	2,358	2,579
		40	9	10	5,213	5,720
		70	11	12	9,324	10,128
	Atlantic	24	**	21	**	4,664
	Cook Inlet*	24	**	30	**	9,247
	Beaufort Platform	48	**	28	**	17,100
	Beaufort Island	48	**	30	**	17,766
	Navarin Platform	48	**	30	**	17,766
	Norton Platform	34	**	27	**	12,054
OIL AND GAS	Gulf	1a	14	16	95	104
		1b	18	20	111	117
		4	19	21	456	480
		6	19	21	685	720
		12	17	19	1,034	1,105
		24	19	21	2,000	2,109
		40	21	23	3,604	3,782
		58	23	25	5,631	5,893
	Pacific	16	8	9	2,358	2,579
		40	9	10	5,213	5,720
		70	11	12	9,324	10,128
	Atlantic	24	**	21	**	4,664
	Cook Inlet*	24	**	30	**	9,247
GAS ONLY	Gulf	1a	14	16	6	6
		1b	18	20	5	5
		4	19	21	20	18
		6	20	21	28	27
		12	17	19	54	49
		24	19	21	89	81
	Pacific	16	11	13	112	98
	Atlantic	24	**	25	**	204
	Cook Inlet*	12	**	29	**	40

Notes: * Existing platforms in Cook Inlet are in the coastal subcategory.
** Produced water from gravel islands in the Beaufort Sea (i.e., the Endicott field) is reinjected per State requirement. There are no platforms currently producing in the Beaufort, Navarin, Norton or Atlantic areas. Economic impacts are evaluated for these projects and projects in the non-coastal region near Cook Inlet that may occur at some point in the future.

Source: ERG estimates.

H.4.1 Existing Structures (BAT)

Gulf of Mexico

The number of structures in production in the Gulf of Mexico is taken from the MMS Platform Inspection System, Complex/Structure data base as of March 1988. Table H-6 describes the data cleaning process used to identify structures for which it is appropriate to calculate water production. Only those structures with

- known number of drilled wellslots
- known type of production
- known to be in production as of March 1988

are considered in this count of structures. This number will differ from that presented in Section Two because all structures are included in that count.

These structures were then divided into categories to correspond to the model projects. Categorization is based on the number of drilled wellslots, and the breaks between the categories were chosen to create the best correspondence between the actual and projected number of wells. A summary of existing structures in the Gulf of Mexico is presented in Table H-7.

The estimated annual water production for projects in the Gulf of Mexico is 885 million bbl/yr (see Table H-8). For comparison, the MMS estimate of produced water generated in the Federal Gulf of Mexico in 1987 is approximately 500 million barrels (Miller 1989; reproduced as Attachment H-1). MMS 1989 indicates that in 1986, approximately 70.2 million barrels of water were discharged in offshore Louisiana state waters while another 5.1 million barrels were discharged in offshore Texas state waters. We assume, for this report, that the volumes of water discharged are equal to the volumes of water generated. We also assume that 1987 water production did not differ drastically from 1986 water production. This results in approximately 573 million barrels/yr of produced water generated in the Gulf of Mexico.

The BAT O&M costs, then, are capable of handling an additional 54 percent over 1987 water production rates. The capital (equipment) costs are determined by peak, not average, flow rates so the infrastructure is capable of handling even larger volumes of produced water. For these reasons, we decided against attempting to incorporate structures in State waters in the mms_desc.wk1

TABLE H-6
DESCRIPTION OF MMS DATA BASE STRUCTURE COUNTS
MARCH 1988

Category	Count	Remaining Count
All structures	3562	3562
Structures classified as production structures, i.e., with zero well slots available and with production equipment	465	3097
Structures with missing information on number of wellslots drilled	33	3064
Structures with zero drilled wellslots	88	2976
Structures known not to be in production	721	2255
Structures with missing information on product type (oil or gas or both)	16	2239
Structures whose drilled wellslots are used solely for injection, disposal, or as a water source	6	2233

Source: Minerals Management Service Platform Inspection System, Complex/Structure see printouts, kre_bat.out, kre_bat2.out and kre_bat4.out.

15-Jan-90

07-Feb-91

TABLE H-7

EXISTING STRUCTURES BY REGION

Structure Type	NUMBER OF STRUCTURES Oil Only <= 4 miles	Oil Only > 4 miles	Oil and Gas <= 4 miles	Oil and Gas > 4 miles	Gas Only <= 4 miles	Gas Only > 4 miles	Total <= 4 miles	Total > 4 miles	Total
Gulf 1a	26	38	27	193	53	337	106	568	674
Gulf 1b	1	9	13	82	22	228	36	319	355
Gulf 4	23	18	10	101	8	156	41	275	316
Gulf 6	0	18	2	124	1	156	3	298	301
Gulf 12	0	22	3	215	0	104	3	341	344
Gulf 24	0	5	8	188	0	39	8	232	240
Gulf 40	0	1	0	2	0	0	0	3	3
Gulf 58	0	0	0	0	0	0	0	0	0
Gulf Totals	50	111	63	905	84	1,020	197	2,036	2,233
Pacific 16	0	0	7	1	0	1	7	2	9
Pacific 40	0	0	0	6	0	0	0	6	6
Pacific 70	0	0	4	8	0	0	4	8	12
Pacific Totals	0	0	11	15	0	1	11	16	27
Atlantic	No existing facilities								
Alaska	No facilities that do not already re-inject produced water								
Totals	50	111	74	920	84	1,021	208	2,052	2,260

Note: Structures in the Gulf of Mexico have been classified according to the number of producing wells. Structures in the Pacific have been classified according to the number of wellslots.

Source: MMS, 1988; CCC, 1988; SAS printout kre_bat6.out; SAS runs dated July 1990.

structr.wk1

TABLE H-8

ESTIMATED AVERAGE ANNUAL PRODUCED WATER GENERATED BY PROJECTS IN THE GULF OF MEXICO

Structure Type	Number	Average Annual Water Production Per Project (kbbl/yr)	Water Production Per Project (kbbl/yr)
Oil			
Gulf 1a	64	90	5,760
Gulf 1b	10	107	1,070
Gulf 4	41	443	18,163
Gulf 6	18	665	11,970
Gulf 12	22	994	21,868
Gulf 24	5	1,939	9,695
Gulf 40	1	3,505	3,505
Gulf 58	0	5,486	0
Oil With Gas			
Gulf 1a	220	95	20,900
Gulf 1b	95	111	10,545
Gulf 4	111	456	50,616
Gulf 6	126	685	86,310
Gulf 12	218	1,034	225,412
Gulf 24	196	2,000	392,000
Gulf 40	2	3,604	7,208
Gulf 58	0	5,631	0
Gas			
Gulf 1a	390	6	2,340
Gulf 1b	250	5	1,250
Gulf 4	164	20	3,280
Gulf 6	157	28	4,396
Gulf 12	104	54	5,616
Gulf 24	39	89	3,471
Total	2,233		885,375

Source: ERG estimates.

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
ROYALTY MANAGEMENT PROGRAM
PRODUCTION ACCOUNTING DIVISION
P.O. BOX 17110
DENVER, COLORADO 80217

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

PAD/RCB
Mail Stop 657

JAN 27 1989

Ms. Maureen Kaplan
Environmental Protection Agency
6 Whittemore Street
Arlington, Massachusetts 02714

Dear Ms. Kaplan:

Subject: Volumes of Water Disposed of in Gulf of Mexico in 1987

The information below is provided in accordance with a telephone conversation between you and John Marshall of this office on January 23, 1989.

The following volume/categories of water were disposed of in the Gulf of Mexico in 1987:

a.	Injected on a lease	19,357,689
b.	Transferred off lease	74,557,893
c.	Surface pit	25,368,097
d.	Overboard	378,978,944
e.	Meter differential	79,870
f.	Well test	146,548
g.	Gathering system	-12,325
	TOTAL	498,476,716*

* or 498.5 million barrels of water disposed of in Gulf in 1987

If you have any questions, please do not hesitate to call Mr. Marshall at 303-231-3635 or our toll-free number 800-525-7922.

Sincerely,

Michael A. Miller

Michael A. Miller, Chief
Reporter Contact Branch

BAT structure counts. Another reason was the difficulty in obtaining a supportable count of such structures. State records are generally maintained on a well basis, not a structure basis. In addition, these well counts include onshore wells that tap offshore fields, coastal wells, and offshore wells with no means of discerning among these categories. Maps, such as those produced by Houston Helicopter, do not specify the number of wells on multi-well platforms nor do they indicate which structures are in production. This is an area that will be investigated further after proposal.

California

The categorization of structures off the California coast is done on the basis of the number of available wellslots. The number of drilled wells is available only on a field basis and so is not appropriate to use here. Table H-7 lists the number of structures by category while Table H-9 presents the estimated annual water production.

The 1987 water volumes for the Federal OCS and the Huntington, South Elwood, Summerland, and Carpinteria fields were added for an actual count of 107 million barrels. The estimated water production is 162 million barrels. The estimated volume of water for the Pitas Point gas field is 112 thousand barrels compared to an actual count of 140.5 thousand barrels (California 1988).

Alaska and the Atlantic

Production in Alaska is currently in Cook Inlet and in the Endicott Field (Beaufort Sea region off the North Slope). The platforms currently existing in Cook Inlet are considered to be coastal and so do not fall under the jurisdiction of this regulation. The Endicott field is already injecting its produced water due to State requirements. No BAT costs, therefore, are incurred by existing Alaska projects.

There is no production in the Atlantic at this time.

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TABLE H-9
ESTIMATED AVERAGE ANNUAL PRODUCED WATER GENERATED BY PACIFIC PROJECTS

Structure Type	Number	Average Annual Water Production Per Project (kbbl/yr)	Water Production Per Project (kbbl/yr)
Oil			
Pacific 16	0	2,358	0
Pacific 40	0	5,213	0
Pacific 70	0	9,324	0
Oil with Gas			
Pacific 16	8	2,358	18,864
Pacific 40	6	5,213	31,278
Pacific 70	12	9,324	111,888
Gas			
Pacific 16	1	112	112
Total	27		162,142

Source: ERG estimates.

H.4.2 Projected Structures (NSPS)

Section Four presents the methodology used to project the number of structures for the 1986-2000 time period. Table H-10 summarizes the number of structures under the $21/bbl oil price scenario with restricted development. Table H-11 lists the annual average volume of water produced during this time period. The average annual volume of water produced is approximately 511 million barrels.

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TABLE H-10

NSPS STRUCTURE ALLOCATIONS
RESTRICTED ACTIVITY

$21/bbl SCENARIO

Region	Model	All Platforms Total	All Platforms Oil	All Platforms Gas	Within 4-Miles Total	Within 4-Miles Oil	Within 4-Miles Gas	Beyond 4-Miles Total	Beyond 4-Miles Oil	Beyond 4-Miles Gas
Gulf										
	Gulf 1b	76	12	64	23	0	23	53	12	41
	Gulf 4	235	89	146	60	27	33	175	62	113
	Gulf 6	123	34	89	43	15	28	80	19	61
	Gulf 12	180	84	96	14	14	0	166	70	96
	Gulf 24	114	62	52	0	0	0	114	62	52
	Gulf 40	27	27	0	0	0	0	27	27	0
Pacific										
	Pacific 40	3	3	0	0	0	0	3	3	0
	Pacific 70	4	4	0	0	0	0	4	4	0
Atlantic										
	Atlantic 24	0	0	0	0	0	0	0	0	0
Alaska										
	Cook Inlet 12	1	0	1	0	0	0	1	0	1
	Cook Inlet 24	1	1	0	0	0	0	1	1	0
	B. Gravel Island*	2	2	0	2	2	0	0	0	0
Total Platforms - All Regions		766	318	448	142	58	84	624	260	364

* Oil only; all other projects are assumed to produce oil and casinghead gas.

TABLE H-11
ESTIMATED AVERAGE ANNUAL NSPS WATER PRODUCTION
$21/BBL RESTRICTED DEVELOPMENT SCENARIO

Project Type		Model	Average Annual Water Production (kbbl/yr)	Number of Structures	Annual Volume of Water Produced (kbbl/yr)
OIL AND GAS	Gulf	1b	117	12	1,404
		4	480	89	42,720
		6	720	34	24,480
		12	1,105	84	92,820
		24	2,109	62	130,758
		40	3,782	27	102,114
	Pacific	40	5,720	3	17,160
		70	10,128	4	40,512
	Atlantic	24	4,664	0	0
	C. Inlet	24	9,247	1	9,247
OIL ONLY	Platform	48	17,100	0	0
	Island	48	17,766	2	35,532
GAS ONLY	Gulf	1b	5	64	320
		4	18	146	2,628
		6	27	89	2,403
		12	49	96	4,704
		24	81	52	4,212
	Pacific	16	98	0	0
	Atlantic	24	204	0	0
	C. Inlet	12	40	1	40
NUMBER OF AFFECTED STRUCTURES				766	
TOTAL WATER PRODUCED (kbbl/yr)					511,054

Source: ERG estimates.

APPENDIX I

BASE CASE FINANCIAL ASSUMPTIONS AND RATES

The economic and financial accounting assumptions used in the economic model are based upon common oil industry financing methods and procedures. Changes in tax computations due to the Tax Reform Act of 1986 (Public Law 99-514) are incorporated in the ERG model.

I.1 INCREMENTAL IMPACT OF MODEL PROJECT ON CORPORATE INCOME TAX RATE

It is assumed that the model projects are incremental to the other activities of the company, and therefore, the net taxable income is marginally taxed at the U.S. corporate rate of 34 percent. This assumption implies that the company has at least $100,000 of other net income without this project. In addition, it is assumed that any net losses in the initial years of a project can be applied to the net income of other projects, so that an effective tax shield of 34 percent of the loss is realized. Therefore, the yearly net cash outflow is 100 percent minus 34 percent, or 66 percent of the year's loss. This is appropriate because of the customary size and level of activities of firms undertaking offshore oil exploration and production. The basis for federal income is gross revenues minus royalty payments, severance taxes, depletion and depreciation allowances, and operating costs.

I.2 SEVERANCE TAXES

Since the Outer Continental Shelf regions are under the jurisdiction of the Federal government, it is assumed that state severance taxes are not applicable to the revenues generated by OCS production. Consequently, severance taxes are not included in the analysis of model projects located in Federal waters. The projects expected to be located in state waters and therefore subject to severance taxes for tax purposes are the Gulf 1-well, 4-well, 6-well, 12-well, and 24-well platforms; Cook Inlet projects, the Beaufort Sea 48 well gravel island; and the California 40 wellslot platform.

Texas state severance taxes are 4.6 percent on oil and 7.45 percent on gas. Louisiana imposes a 12.5 percent severance tax on oil and a $0.07 per Mcf tax on gas. (Using the 1982 wellhead price, the Louisiana $0.07 tax is equivalent to a 1.3 percent tax on gas.) Based on cumulative oil and gas production data for Texas and Louisiana offshore leases through 1981, an average severance tax of 6.19 percent was calculated and this value is used for the Gulf projects in State waters.

California, at present, has no severance taxes.

The Alaska severance tax structure consists of nominal rates that are then adjusted by a formula. The formula is referred to as the ELF, the Economic Limit Factor.

Nominal tax rates on oil are 12.25 percent of gross revenues for the first 5 years of production and 15 percent thereafter. The ELF formula for oil is:

$$ELF = \left(1 - \frac{PEL}{TP}\right)^{\frac{460 \times WD}{PEL}}$$

where:

PEL = monthly production at the economic limit
TP = total monthly production
WD = well days for the month (assumed to be 30).

The monthly production at the economic limit value is confidential between the oil company and the Alaska Department of Revenues. Three hundred bbl/day/well or 9,000 bbl/month/well is used for the economic limit (PEL) in this analysis (Logsdon 1988).

As an example, suppose monthly production is 50,000 barrels. Then the ELF is:

$$ELF = \left(1 - \frac{9,000}{50,000}\right)^{\frac{460 \times 30}{9,000}}$$

$$= (0.82)^{1.533} = .74$$

If the ELF is greater than 0.7, then the tax rate is the nominal rate. the ELF is less than 0.7, severance taxes are calculated as follows:

For the first five years of production:

Oil Severance Taxes = Gross revenues x 12.25 percent x ELF.

After the first five years of production:

Oil Severance Taxes = Gross revenues x 15.00 percent x ELF.

The oil ELF is applied as long as it is positive.

The nominal severance tax rate on natural gas is 10 percent, which is adjusted by the following ELF formula:

$$ELF = 1 - \frac{PEL}{TP}$$

where:

PEL = monthly production at the economic limit
TP = total monthly production.

Three thousand Mcf/day/well or 90,000 Mcf/month/well is used for the economic limit (Logsdon 1988). Gas severance taxes are calculated as follows:

Gas Severance Taxes = Gross revenues x 10.00 percent x ELF.

Unlike the oil severance ELF, the gas ELF is applied regardless of value, as long as it is positive.

For offshore leases, the basis for the severance tax calculation would be on the basis of (gross revenues - exempt revenues) where royalty payments to state government are considered exempt revenues.

I.3 ROYALTY RATES

Operators of oil- and gas-producing properties are usually required to pay royalties to the lessors or owners of the land based on the value of extracted production. This includes the Federal government for OCS leases and state governments for leases located in state waters. In many instances, the royalty rate is a floating rate that varies from year to year, or a complex calculation based on the amount or mix of production. For the model projects, it is assumed that an average fixed rate of one sixth (17 percent) of total gross revenues is the best approximation of royalty payments for a typical large project in Federal waters and 22 percent for a project on a state-owned tract.

I.4 RENTAL PAYMENTS

Rental payments generally comprise a negligible cash outflow in the overall set of costs for an oil and gas project. For this reason, they have been excluded from the analysis.

I.5 DEPRECIATION

The Tax Reform Act of 1986 modifies the Accelerated Cost Recovery System (ACRS) for property placed in service after 31 December 1986. Under the new system, most oil and gas equipment will be classified as seven-year property. The recovery method for this class is double declining balance (Snook and Magnuson, 1986). The schedule used to write off capitalized costs in the model is as follows:

Year 1	14.29% of costs
Year 2	24.49%
Year 3	17.49%
Year 4	12.49%
Year 5	8.93%
Year 6	8.92%
Year 7	8.93%
Year 8	4.46%

Year 1 in the above table is defined as the first year in which the equipment is placed in service. According to relevant accounting principles, this is the first year in which the equipment produces oil or gas.

The value of the deduction for depreciation is reduced by inflation. To maintain the calculations on a constant dollar basis, the value of the deduction is adjusted downwards in later years by the inflation rate. See Section I.8.

I.6 BASIS FOR DEPRECIATION

The Tax Reform Act of 1986 repealed the Investment Tax Credit (Snook and Magnuson, 1986; Coopers and Lybrand, 1986). This means that the initial basis for depreciation is 100 percent of the total capitalized costs.

I.7 CAPITALIZED COSTS

It is assumed that the tax payer (oil company) elects to expense intangible drilling costs incurred in the development of oil and gas wells. Intangible drilling costs (IDCs) are estimated, on the average, to represent 60 percent of the cost of production wells and their infrastructure (Commerce, 1982; Commerce, 1983; API, 1986). The Tax Reform Act limits major integrated producers to expensing 70 percent of IDCs with the remaining 30 percent capitalized. (That is, a major may only expense 0.60 times 0.70, or 42 percent of its IDCs.) Independents are still allowed to expense 100 percent of their IDCs. The remaining 40 percent of the total cost is capitalized and treated as depreciable assets for tax purposes (Snook and Magnuson, 1986).

Dry holes are written off in the year in which the cost is incurred. For independents, the proportion of the exploratory drilling cost that is capitalized is therefore equal to 40 percent of the total drilling cost times the discovery efficiency. For majors, the proportion is 58 percent of the total drilling cost times the discovery efficiency. The remaining drilling costs are expensed.

I.8 INFLATION RATE

The effective value of depreciation and cost-basis-depletion deductions is reduced by inflation since the expenditures occur in year(s) prior to the deduction. The model calculates an "adjusted depreciation" as follows:

$$\text{Adjusted depreciation in Year X} = \frac{\text{Depreciation in Year X}}{(1 + \text{inflation rate})^{\text{Year X}}}$$

An "adjusted cost-basis-depletion" is calculated in a similar manner.

The change in the "Fixed Weight Price Index" is used as a measure of inflation for this analysis. Since 1982, the values are:

1982	6.2
1983	4.1
1984	4.0
1985	3.7
1986	2.8

for an average of 4.2 percent (Economic Report, 1987). This value is used in the analysis to deflate the depreciation and depletion.

I.9 ESCALATION OF GENERAL PROJECT COSTS IN REAL TERMS

It is assumed that costs will remain constant in real terms, i.e., the rate of increase in material and labor costs is equal to the rate of inflation.

I.10 OIL DEPLETION ALLOWANCE

The ERG model calculates depletion on a cost basis, which is appropriate for major producers. Cost depletion allows the producer to recover the leasehold cost over the producing lifetime of the well. The leasehold cost consists of the bonus bid (see Appendix C), and certain geological, geophysical and legal costs (see Appendix D).

Cost depletion is based on units of production and is represented by the following formula:

$$B = \frac{S}{U + S}$$

where:

B = adjusted basis of leased property
S = units sold during the period
U = units remaining at the end of the period.

The initial basis of the property used in the ERG model consists of the bonus bid and the geological and geophysical expenses. (That is, the legal costs incurred in acquiring the lease are not explicitly included in the model. It is assumed they form a minimal increment to the overall leasehold cost.) The basis is then adjusted downward to account for the depletion taken in each period. The portion of the adjusted basis taken as depletion in any given period is the units sold during the period, divided by the units sold and the recoverable units remaining. For the purposes of the model, it is assumed that all units produced in a period are sold in the same period. Thus, the depletion for any given period is equal to the adjusted basis multiplied by the ratio of units produced in the period to the sum of the units produced and remaining. In this manner, the leasehold cost is amortized over the productive life of the well.

The value of the cost-basis depletion is reduced in later years by inflation. See Section I.8 for the methodology used to correct for this in the calculations. The value used in the annual cash flow is the inflation-adjusted value. The unadjusted value is used to calculate the basis for depletion in subsequent years.

I.11 SALVAGE

It is assumed that the after-tax cost to remove the infrastructure and to retire the well at the end of its economic life is approximately equal to their salvage values. Hence, there is no additional positive or negative cash flow.

I.12 INVESTMENT TAX CREDIT

The Tax Reform Act of 1986 repealed the Investment Tax Credit (Snook and Magnuson, 1986; Coopers and Lybrand, 1986).

I.13 WINDFALL PROFITS TAX

A phaseout of the Windfall Profits Tax of 1980 will begin no later than January 1991, with a 33-month phaseout beginning as early as January 1988. Under these conditions, the Windfall Profits Tax will apply, at most, to the first few years of the projects. In addition, the industry is trying to have the tax repealed in its entirety at an earlier date (OGJ, 1987) and the Senate voted to repeal the tax in July 1987. For these reasons, the effects of the Windfall Profits Tax have not been included in the analysis.

I.14 DISCOUNT RATE

The discount rate used in this analysis represents the opportunity cost of capital for investments in oil and gas production (Brigham, 1982). The cost of capital is the investor's expected rate of return for a particular investment. That is, the cost of capital is the return that could be earned elsewhere in the economy on projects of equivalent risk. The riskier the investment, the higher the cost of capital.

The opportunity cost of capital is modeled as:

$$\text{Real cost of Capital} = \frac{1 + \text{nominal cost}}{1 + \text{inflation rate}} - 1$$

where:

nominal cost = [equity cost * equity share] + [debt share * debt cost]

The equity cost is the sum of the risk-free return and the risk premium. For the risk-free return, ERG uses the average return on long-term U.S. Treasury bonds. The risk premium is the product of the average industry risk (i.e., the industry beta) and the market risk for long-term investment.

The debt and equity shares are the portions of capital financed by debt and equity, respectively. These are estimated by the average share of debt o equity in the firm's value.

The debt cost is the after-tax cost of debt, i.e., the product of the current cost of debt and (1 minus the corporate tax rate). For the current cost of debt, the interest rates for Moody's Baa corporate bonds are used.

The next point to consider is whether to use long-term or short-term estimates for each of these parameters. The productive life of the project can be several decades in the ERG model. On this basis, long-term average values are used in estimating the cost of capital.

Table I-1 compiles twenty-year averages for risk-free returns, current cost of debt, and inflation rates. (Most projects in this study are no longer profitable after twenty years of production.) Table I-2 gives the average long-term debt-to-capital ratio for 19 major integrated companies. This ratio varies around 25 percent for the time period investigated. On this basis, we

TABLE I-1

TWENTY-YEAR AVERAGES FOR RISK-FREE, CORPORATE BORROWING, AND INFLATION RATES

YEAR	RISK-FREE RATE	CORPORATE BORROWING RATE	INFLATION RATE
1967	5.07	6.23	2.6
1968	5.65	6.94	3.7
1969	6.67	7.81	4.4
1970	7.35	9.11	3.6
1971	6.16	8.56	3.5
1972	6.21	8.16	2.9
1973	6.84	8.24	5.5
1974	7.56	9.50	7.8
1975	7.99	10.61	8.0
1976	7.61	9.75	5.3
1977	7.42	8.97	5.1
1978	8.41	9.49	6.2
1979	9.44	10.69	8.5
1980	11.46	13.67	9.3
1981	13.91	16.04	9.3
1982	13.00	16.11	6.2
1983	11.10	13.55	4.1
1984	12.44	14.19	4.0
1985	10.62	12.72	3.7
1986	7.68	10.39	2.8
Average	8.63	10.54	5.3

Source: Economic Report, 1987, Table B-68, 10-year U.S. Treasury securities, and Moody's Baa corporate bonds, Table B-4, inflation rate.

TABLE I-2

DEBT/CAPITAL RATIO (%)
MAJOR INTEGRATED OIL COMPANIES IN 19-COMPANY ERG GROUP
(1977-1985)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Amerada Hess	36.7	36.0	30.0	29.5	35.2	38.9	40.3	40.1	40.6
American Petrofina	26.4	45.8	40.4	33.5	28.1	26.0	31.4	39.1	40.8
Atlantic Richfield	34.2	34.6	29.4	27.1	28.9	28.7	26.2	26.9	43.9
Diamond Shamrock	38.1	38.4	38.1	36.0	34.0	34.3	37.0	28.1	40.7
Exxon	14.4	13.3	13.3	12.5	12.0	10.6	10.5	11.6	10.4
Getty Oil (Texaco)	5.8	4.7	4.0	10.8	9.8	16.6	--	--	--
Gulf Oil (Chevron)	13.5	14.1	13.0	10.7	13.0	14.6	--	--	--
Kerr-McGee	20.9	16.6	20.4	24.1	33.1	29.7	27.1	23.5	23.4
Mobil Oil	25.2	25.6	21.3	19.0	17.3	21.1	24.4	40.9	35.8
Murphy Oil	35.5	40.5	32.3	19.1	21.1	16.9	15.1	14.3	13.7
Occidental Petroleum	26.8	39.4	39.0	25.6	20.1	43.5	34.0	43.3	47.6
Phillips Petroleum	21.0	16.3	13.6	12.4	15.0	22.7	23.3	26.0	64.3
Shell Oil (Royal Dutch Petroleum)	20.6	18.4	30.6	33.0	31.3	27.8	19.1	17.3	14.6
Standard Oil of California (Chevron)	16.2	19.7	17.2	13.0	12.4	11.3	10.6	43.4	28.9
Standard Oil of Indiana (Amoco)	25.2	23.5	21.1	18.8	21.4	22.0	20.1	17.3	16.9
Standard Oil of Ohio	71.9	65.4	50.3	39.8	36.1	33.8	29.2	26.4	25.4
Sun Company	18.9	19.4	16.8	34.5	28.6	24.7	24.8	25.3	20.7
Texaco	19.1	24.8	21.8	18.0	15.1	12.8	14.1	41.0	31.6
Union Oil Company	26.8	28.6	26.0	21.9	18.3	18.6	17.6	15.3	64.1
Unweighted Company Average[a]	26.2	27.6	25.2	23.1	22.7	23.9	23.8	28.2	33.1

Source: S&P 1982; S&P 1986.

[a]Simple average calculated from the ratios for all companies in the sample.

use 25 percent as the debt share and 75 percent as the equity share in the cost of capital calculations.

The cost of capital is calculated in Table I-3. Sources for the remaining parameter values are cited in the table. The estimated cost of capital is 7.55 percent. This value is rounded upwards to 8 percent for use in the analysis.

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TABLE I-3

COST OF CAPITAL CALCULATIONS

PARAMETER	VALUE	SOURCE
Risk-free return	8.63%	See Table I-1.
Industry beta	0.84%	Kavanaugh, M. 1987. Average beta for 24 petroleum companies, Standard & Poor's Stock Reports.
Market risk	8.00%	Brealey and Myers 1984.
Risk premium	6.72%	Calculated.
Cost of debt	10.54%	See Table I-1.
Debt cost	6.96%	Tax Reform Act of 1986, highest corporate tax bracket is 34 percent.
Debt share	25.00%	See text.
Equity share	75.00%	See text.
Inflation rate	5.30%	See Table I-1.
Nominal cost	13.25%	
Real cost	7.55%	

Source: as listed.

APPENDIX J

ERG ECONOMIC MODEL FOR OFFSHORE PETROLEUM PRODUCTION

J.1 INTRODUCTION

The ERG model simulates the costs and petroleum production dynamics expected in the development and production of an offshore well for oil and/or gas. Data to define the well and the petroleum reservoir are entered into the model. Through the use of internal algorithms, the model calculates the economic and engineering characteristics of the project. Outputs from the model include: production volume, project economics, and summary statistics.

The model is structured to be flexible. It is capable of modeling projects on a single-well or multiple-well basis with exploration and development occurring within a single year or over a decade. Flexibility is possible through the use of user-specified inputs for a wide variety of variables. Inputs include, but are not limited to: lease bids, development schedules, infrastructure and operating costs, initial petroleum production, production decline rates, tax rate schedules, and wellhead prices. The data define the proposed development project.

From the user-specified data, costs and production performance are calculated on a yearly basis through a series of algorithms. The model calculates yearly production, present value of yearly production and present value of production income. The model generates a consistent set of annual values and summary statistics to evaluate the project. All dollar amounts in this analysis and in the accompanying printout are in thousands of 1986 dollars.

J.1.1 Model Phases

The project life of an offshore well for oil and/or gas is divided into five phases: (1) from lease bid to the start of exploration, (2) from the start of exploration to the start of delineation, (3) from delineation to the start of development, (4) from the start of development to the start of production, and (5) production. The length of each of these phases is an exogenous variable input to the model.

For multiple well projects, the impetus to begin production is great and the production phase may overlap the development phase. That is, petroleum production may begin while some wells are still being drilled. The ERG model is capable of modeling this situation (see Section J.2).

The project operates for 30 years or for as long as it is profitable. Project economics are evaluated annually within the model algorithms and the project is shut down at the first negative cash flow.

J.1.2 Economic Overview of the Model

The economic character of the model phases is quite different. Phases one through four generate cash outflows; no revenues are earned during this period. The fifth phase, production, generates net cash inflows. During this phase, the project will continue to operate as long as operating cash inflows exceed cash expenses.

J.1.2.1 Cash Flows - Categorization

The model deals with a number of basic cash flows (or resource transfers). The basic cash flows are as follows:

Leasing Phase:	Lease bid - cost of acquiring rights to explore and develop a tract of land.
Exploration Phase:	G&G costs - geological and geophysical expenses incurred prior to drilling.
	Exploration well costs - cost of drilling an exploration well.
	Incremental drilling costs - additional cost of drilling due to new regulations concerning muds and cuttings.
Delineation Phase:	Delineation well costs - costs of drilling a delineation well.
	Incremental drilling costs - additional cost of drilling due to new or revised regulations concerning drilling fluids and drill cuttings.

Development Phase:	Development well costs - costs of drilling a development well (includes prorated cost of building and installing a petroleum production platform, see Appendix F).
	Infrastructure costs - cost of production equipment installed on the platform.
	Incremental drilling costs - additional cost of drilling due to new or revised regulation concerning drilling fluids and drill cuttings.
Production Phase:	Revenues from oil and gas production - production levels multiplied by price forecasts.
	O&M costs - cost of operating and maintaining the well.

The basic cash flows, summarized above, are affected by a number of factors that are depicted in Table J-1 below. The matrix in Table J-1 can be illustrated by using the lease bid as an example. Initially, the lease bid generates a cash outflow in the initial phase of the project. Three factors, however, will allow a portion of that outflow to be recouped during the production phase of the project. These factors, the <u>Federal and state corporate tax rates</u> and the <u>depletion allowance</u> for major integrated producers, are denoted by plus signs in the table because of their positive effect on the project cash flow. (Major producers are allowed to amortize the leasehold cost over the productive life of the well and use this allowance to reduce taxable revenue. For a more detailed discussion of the depletion allowance, see Section I.10.)

J.2 STEP-BY-STEP DESCRIPTION OF THE MODEL

The ensuing discussion is a sequential overview of how the code operates. It starts with the lease bid and ends with the shut down of the well either after 30 years of production or when the project becomes unprofitable. To illustrate the code, the inputs, calculations, and outputs for a 12-well oil and gas platform in the Gulf of Mexico are used. The project was chosen because its size and production type are common in the Gulf (see Appendix A).

The discussion is based on the computer printout that is attached to this appendix. Identification numbers for specific lines are given in the right-hand margin. A list of user-specified inputs is given in Table J-2. <u>All dollar values (e.g., costs and revenues) are expressed in thousands of 1986 dollars</u>. Values on spreadsheet may differ in the final digit from numbers presented in the text due to rounding.

TABLE J-1

EFFECT OF TAX AND ACCOUNTING SYSTEMS ON CASH FLOWS

AFFECTING FACTORS	LEASE BID	G&G COSTS	EXPLORATION WELL COSTS	DELINEATION WELL COSTS	DEVELOPMENT WELL COSTS	PRODUCTION EQUIPMENT COSTS	BAT/ NSPS INCREMENTAL DRILLING COSTS	PRODUCTION REVENUES	OPERATING EXPENSES
Federal Corporate Income Tax	+	+	+	+	+	+	+	-	+
State Corporate Income Tax	+	+	+	+	+	+	+	-	+
Depletion Allowance	+	+ (cost basis)						+ (percentage basis)	
Royalties								-	
State Severance Tax								-	
Depreciation			+	+	+	+	+		
Current Expensing			+	+	+	+	+		+

+ = Increases net cash inflow. In the case of expense items, cash outflows, the existence of tax rates mitigates the cash outflows.

- = Decreases net cash inflow. In the case of revenue items, cash inflows, the existence of tax rates decrease cash inflows.

TABLE J-2

EXOGENOUS VARIABLES PROVIDED TO ERG ECONOMIC MODEL

IDENTIFICATION NUMBER	PARAMETER
1	Lease cost.
2	Geological and geophysical expense.
4	Real discount rate.
5	Inflation rate
6	Years between lease sale and exploration.
7	Percent of cost considered expensible intangible drilling costs.
8	Drilling mud cost increment.
9	Federal corporate tax rate.
10	Drilling cost per exploratory well.
12	Discovery efficiency.
13	Platforms per successful exploratory well.
23	Years between start of exploration and delineation.
24	Number of delineation wells drilled.
25	Cost per delineation well.
36	Total platform cost.
37	Pollution control capital costs (produced water).
38	Years between delineation and development.
39	Number of development wells drilled.
40	Number of development wells drilled per year.
41	Drilling cost per development well.
48	Annual Pollution Control Capital Costs.
56	Percent watercut in oil and gas to start.
57	Oil and gas production decline rate.
58	Cost escalator.
59	Royalty rate.
62	Depreciation schedule.
63	Severance tax rate - oil.
64	Severance tax rate - gas.
65	Gas only flag.
66	Years between development and production.
67	Years at peak production.
68	Oil - peak production rate (bbl/day).
69	Gas - peak production rate (MMCF/day).
70	Number of producing wells.
71	Number of wells put in service per year.
72	Wellhead price per barrel - oil.
73	Wellhead price per Mcf - gas.
74	Total operating costs.
75	Annual pollution control equipment operating cost (produced water).

Source: ERG estimate.

J.2.1 Phase One - Leasing

The lease cost (line 1) is a user-specified input, the value of which is based on 1986 lease sales in the Gulf of Mexico. See Appendix C for regional lease costs and their derivation.

J.2.2 Phase Two - Exploration

Line 2 represents the costs of geological and geophysical (G&G) investigation of the site as a percentage of lease cost. The value shown in line 2 is based on information in the API cost survey for 1986 (see Section D.1). The total leasehold cost (line 3) is the sum of the lease bid and G&G expenses. The total leasehold cost is a cash outflow in Year 0 of the project; the value on line 3 is therefore the present value of the leasehold cost. The leasehold cost forms the basis for the depletion allowance as calculated on a cost basis for major integrated producers.

Line 4 is the real discount rate, i.e., the cost of capital. This value will be used throughout the code to discount future cash inflows, cash outflows, and production in order to express them in present value terms.

Line 5 is the inflation rate. This parameter is used to reduce the value of the deductions for cost-basis depletion and depreciation in future years.

Line 6 is the number of years between the lease bid and the start of exploration. For all projects in the Gulf of Mexico, exploration begins in the same year as the lease sale. For other regions, the number of years between lease bid and the start of exploration varies from one to two years (see Appendix B).

The petroleum industry has considerable latitude in its treatment of costs. Unlike most other industries, an oil company can expense, in the period incurred, costs that would normally be capitalized. The immediate expensing of a portion of capital costs provides a significant tax advantage to an oil company.

Line 7 contains the percentage of drilling costs that are considered "Intangible Drilling Costs" (IDCs) and are eligible for expensing. An initial value of 60% is used in this analysis as the percentage of costs considered

IDCs. This is based on annual surveys of expenditures (see Section I.7). Under the Tax Reform Act of 1986, independents may expense 100% of IDCs, while majors may expense only 70% of the IDCs. Since the project is assumed to be a venture by a major company, the value shown is 42 percent (0.60 x 0.70).

The additional costs due to new pollution control regulations on drilling muds and cuttings are entered in line 8. The Federal corporate income tax rate is entered on line 9.

The drilling cost for a well depends on the depth drilled, environmental requirements, and regional costs for parts and labor. The cost of drilling a well has been summarized in Section D.3, and is entered on line 10. The discovery efficiency, the ratio of productive wells to all wells drilled, also varies by region, depending upon the predictability of the reservoir. All-time regional averages are used in this study (see line 12, Section D.2). Line 13 is the number of platforms built per successful exploratory well. This parameter varies by region, see Section C.3.

Line 14 displays the exploratory well costs for the project. The exploratory well cost is the sum of the cost of drilling the well and the drilling mud cost increment divided by the product of the discovery efficiency and the number of platforms per successful well. This cost is spread over the number of years between the start of exploration and the start of delineation (see line 23). For the 12-well GOM project, the annual exploratory well costs are:

$$\text{Annual Exploratory Well Costs} = \frac{(\text{well cost} + \text{incremental drilling fluid cost})}{(\text{discovery efficiency} * \text{no. of platforms per successful well})} \div \text{Years of Exploration}$$

$$= \frac{(4,355 + 0)}{(.14 * 4.3)} \div 1 = \$7,234$$

One year for exploration is scheduled for this project (line 23).

The annual cost of successful efforts (line 15) is the product of the annual exploratory well cost and the discovery efficiency:

$$\text{Annual Cost of Successful Efforts} = \text{Annual Total Well Cost} * \text{Discovery Efficiency}$$

$$= (\$7,234 * .14) = \$1,013$$

Annual expensed costs (line 16) are the sum of two factors: (1) the product of the annual cost of successful efforts times the percent costs expensed (line 7) and (2) dry hole expenses:

Annual Expensed Costs = (cost of successful efforts x % expensed) + exploratory costs x (1-disc. eff.)

= ($1,013 * .42) + ($7,234 * .86)

= $425 + $6,221

= $6,646 (note rounding)

In other words, the annual expensed cost is the sum of unsuccessful efforts and the expensible portion of intangible drilling costs for successful wells.

The expensed cost is $6,646/yr for each year of exploration. The actual cash outflow, however, is dependent upon the corporate tax rate. The expenses reduce the tax bill for a profitable corporation. The calculations to determine the actual cash outflow, shown below, assume a marginal corporate tax rate of 34 percent (see line 17).

Expensed Cash Flows = (1 - tax rate) * Expensed Costs

= (1 - .34) * $6,646 = $4,387

Capitalized cash flows, line 18, are the exploration costs that are not expensed. The proportion of drilling efforts that may be expensed depends upon whether the corporation is a major or independent producer. For the Gulf of Mexico project, a major producer is assumed. Under the Tax Reform Act of 1986, a major may expense 70 percent of the intangible drilling costs (IDCs) and the IDCs are estimated to be 60 percent of the drilling costs. For a major, then, 1 - (0.6 x 0.7) or 58 percent of the successful drilling costs are capitalized:

Capitalized Cash Flows = 0.58 * Cost of Successful Effort (line 18)

= 0.58 * $1,013 = $587

Since capitalized costs generate no tax shield in the year incurred, the capitalized cash flow is equal to the capitalized cost.

Once the various exploration costs and cash flows have been calculated, they are put in present value terms as of the lease year. For all Gulf of

Mexico offshore projects, exploration costs are incurred in Year 0, the year the lease was obtained. For these projects, the present value of all exploration costs are the same as the value for Year 0.

Present values are calculated for expensed exploration cash flows, capitalized exploration cash flows, and all exploratory costs (lines 19, 20, and 22). The sum of all capitalized exploration cash flows is given in line 21.

J.2.3 Phase Three - Delineation

If an exploratory well discovers petroleum, delineation wells may be drilled to confirm the size and extent of the reservoir. In this project, one year is assumed to pass between the start of exploration and the start of delineation (line 23, see Appendix B for timing assumptions). Two delineation wells are drilled (line 24), each costing the same as an exploratory well (line 25). As with exploratory wells, the costs are allocated over the number of platforms per successful exploratory well (line 27).

The annual delineation costs (line 28) are the product of the number of delineation wells and the cost per delineation well, divided by the number of platforms per successful exploratory well. This cost is allocated over the number of years between the start of delineation and the start of development if its value is greater than one (line 37). For the 12-well Gulf of Mexico project, the annual delineation well costs are:

Annual Delineation Well Cost	=	(well cost + incremental drilling fluid cost) * number of delineation wells + number of platforms per successful discovery
	=	($4,355 * 2) + 4.3
	=	$2,026

The tax shield (line 29) is the product of the annual delineation cost, the percentage of drilling costs considered intangible drilling costs (which are therefore eligible for expensing), and the corporate tax rate:

Tax Shield = Drilling Cost
*Percentage of drilling costs considered IDCs
*Percent of IDC that can be expensed
*Federal corporate tax rate

= \$2,026 * 0.6 * 0.7 * .34

= \$289

Expensed cash flow (<u>line 30</u>) is the annual delineation well cost times the expensed percentages of IDCs minus the tax shield:

Expensed Cash Flow = (Annual delineation cost
* percentage considered expensible IDCs)
\- tax shield
= (\$2,026 * 0.42) - \$289
= \$562 (note rounding)

Capitalized cash flow (<u>line 31</u>) is the annual delineation well cost times the portion of costs that cannot be expensed.

Capitalized cash flow = delineation costs * (1 - 0.42)

= \$2,026 * .58

= \$1,175

Once the various delineation costs and cash flows have been calculated, they are put in present value terms of the half year. The delineation costs are incurred in Year 1 of the 12-well Gulf of Mexico project. The costs and cash flows must be adjusted by the time value of money, i.e., the discount rate. For this project, the delineation costs are discounted as follows:

Present Value = cost in Year 1 ÷ 1.08^1

For the expensed cash flow, this is

PV expensed cash flow = \$561 ÷ 1.08

= \$520

Present values are calculated for expensed cash flow, capitalized delineation costs, and total delineation costs (<u>lines 32-35</u>).

J.2.4 Phase Four - Development

The costs of production equipment and other infrastructure costs are entered in line 36. Additional construction costs for the installation of pollution control equipment are entered separately in line 37. For this project, there are two years between the start of development and the start of production (see line 66). Costs for both types of construction are allocated over the first year or over the years of construction minus one year (see line 47).

The development phase in the code is structured to accommodate the drilling of development wells after a reservoir has been determined. Separate entries for the total number of wells in the project, the number of wells drilled each year, and the drilling cost per well appear in lines 39 through 41, respectively.

Lines 42 through 48 calculate the costs incurred each year from the drilling of development wells, and the construction of production and pollution control facilities. The total annual capital development costs are given in line 49.

The tax shield, line 50, is the product of the annual total capital development costs, the corporate tax rate, and the percent of costs expensed. For Year 1 of the 12-well Gulf of Mexico project, this is $11,660 x 0.34 x .42 or $1,665. The expensed cash flow, line 51, is the total annual capital development costs (line 49) times the percentage of costs expensed (line 7) minus the tax shield (line 50). For Year 2, this is ($29,436 x 0.42) - $4,203 or $8,160. The capitalized cash flow, line 52, is the product of total capital costs and (1 - the percentage of expensible IDCs). For Year 3, this is $19,624 x 0.58 or $11,382. Note that the sum of the tax shield, the expensed costs and capitalized costs is equal to the total costs.

As with the exploration costs, development costs are discounted to determine their present value in the lease year. Present values of all development costs, expensed development costs, and capitalized development costs are given in lines 53 through 55, respectively.

J.2.5 Phase Five - Production

In the production phase of the project, a variety of financial and engineering variables interact to form the economic history of the well. Line 57 provides the production decline rate for oil and gas. The ERG model incorporates an exponential function for production decline, i.e., a constant proportion of the remaining reserves is produced each year. For every barrel produced in the initial year of operation in this project, 0.85 barrel is produced in the second year, 0.85^2 or 0.723 barrel in the third year, and so forth.

The ERG model is capable of handling cost escalation (see line 58). In this report, we are considering costs in real terms, and thus no escalation is assumed.

The royalty rate paid to the lessor of the land is provided in line 59. The depreciation schedule is listed in line 62. State severance taxes on oil and gas are given in lines 63 and 64, respectively. Note the flag for calculating severance taxes for Alaska since these must be adjusted by the Economic Limit Factor (ELF).

Line 65 is a flag to identify gas-only projects. The flag is necessary for the proper calculation of depletion on a cost basis within the code.

The number of years that a well produces at its peak rate is given in line 67. The peak production rates per well for oil and gas are given in lines 68 and 69, respectively. Note that these are figures for daily production and that the units for gas production are MMcf/day.

Since not all wells are turned into producing wells (e.g., exploratory wells in offshore operations or reinjection wells), lines 70 and 71 specify the number of producing wells and the rate at which they enter production.

The wellhead prices for oil and gas are entered on lines 72 and 73. Annual operating costs are entered on line 74, while line 75 contains the incremental costs of water disposal due to compliance with pollution control regulations.

Line 77 provides the number of producing wells in service and is calculated from the total number of producing wells and the number of wells that go into service per year. The barrels of oil produced per day (line 78) is a function of the number of wells and the year in which they went into service.

In general, production for a group of wells that went into service in the same year is calculated as:

Daily Production = # of wells x # of barrels/day x decline rate^a

where a = year of production - number of years at peak production

This is extended to calculate production for wells going into service in different years. For example, in line 78,

Daily Production Year 3 = 6 wells * 500 bopd
= 3,000 bopd
Year 4 = (6 * 500) + (4 * 500)
= 3,000 + 2,000
= 5,000 bopd

Year 5 = (6 * 500 * 0.85) + (4 * 500)
= 2,550 + 2,000
= 4,550 bopd
Year 6 = (6 * 500 * 0.85^2) + (4 * 500 * 0.85)
= 2,168 + 1,700
= 3,868 bopd

and so forth.

The annual oil production is calculated as 365 times the daily production (<u>line 80</u>). The price per barrel is repeated in <u>line 81</u> for convenience in cross-checking the gross revenues for oil production (line 85). <u>Lines 82, 83, and 84</u> list the daily gas production, annual gas production, and wellhead price per Mcf.

J.2.5.1 <u>Income Statement</u>

Lines 85 through 107 comprise an income statement that is repeated annually for a thirty-year project lifetime. Since most projects become uneconomical before this, lines 108 through 114 check for a negative net cash flow and readjust the actual production, revenues, and cash flows to zero when appropriate.

Lines 85 and 86 list the revenues from oil and gas production. Total cash inflow for the year is given in line 87. Royalty payments are calculated on the basis of gross revenues (lines 88 and 89, see line 60 for the royalty rate). Severance taxes are calculated on the basis of gross revenues minus royalty payments (lines 90 and 91, see lines 63 and 64 for severance tax rates). The economic limit factor (ELF) for the calculation of severance taxes for Alaska is given in lines 92 and 93 (see Section H.2 for a more complete discussion of severance tax calculations for Alaska). Net revenues for Year 3, line 94, are calculated as:

Net revenues = Total Gross revenues - royalty payments
- severance taxes

= $30,783 - $5,738 - $1,034 - $1,259 - $227

= $22,525 (note rounding)

Operating costs are given in line 95; incremental operating costs due to pollution control appear in line 97. The entry on line 98 is the sum of the capitalized costs spent in the exploration, delineation, development and production phases to that year:

Capitalized Costs For Year 3 = Capitalized Costs in the Exploration Phase
+ Capitalized Costs in the Development Phase
+ Capitalized Costs in Development Phase up to that year

= $587 (line 21) + $1,175 + $6,763 (line 33) + $17,073 (line 52) = $25,598

The adjusted depreciation allowance is listed in line 99. The depreciation schedule under the Tax Reform Act of 1986 is found on line 62. The unadjusted depreciation allowance is the product of $25,598 (capitalized costs) and the depreciation rate for the appropriate year, e.g., $25,598 x 14.29% = $3,658 for the first year of operation for the project (Year 3).

The figure of $3,658 is the number that would be used in the tax calculations for the company. The value of that deduction, however, has been eroded by inflation. To adjust for this effect, we calculate a deduction that is deflated, e.g., $3,658 + (1 + inflation rate)$^{\text{Year X}}$ or $3,658 + (1.042)^3 = ($3,658 + 1.131) = $3,234, see line 99 and note rounding.

The operating earnings (line 100) are defined as net revenues (line 94) minus operating costs (line 95) minus pollution control operating costs (line 96). For Year 3 of the project:

Operating Earnings = Net revenues - operating costs - pollution control operating costs

= \$22,524 - \$2,312 - \$0 = \$20,212

<u>Line 101</u>, earnings before interest and ODA (oil depletion allowance), subtracts depreciation and amortization from operating earnings. For Year 3,

Earnings Before Interest and ODA = \$20,212 - \$3,234 = \$16,978 (note rounding)

For major integrated producers, the depletion allowance is calculated on a cost basis, that is, the leasehold cost is amortized over the productive life of the well:

$$\text{Depletion Allowance in "Year X"} = \text{Leasehold Cost} - \text{Depletion Allowance Taken} \times \frac{\text{"Year X" Production}}{\text{Total Production from "Year X".}}$$

for Year 3, the depletion allowance for the Gulf project is:

= (\$11,952 - 0) * x (1,095,000 bbl + 13,875,110 bbl)
(Line 3)

= \$943

Depletion is calculated based on oil production only, unless the gas-only flag is set in Line 65.

The figure of \$943 must be deflated because the leasehold cost was spent in Year 0, but the deduction is not taken until a later year. For Year 3, the <u>adjusted depletion allowance</u> (<u>line 102</u>) is calculated as:

$$\text{Adjusted Depletion Allowance in "Year X" (line 90)} = \text{Depletion Allowance in "Year X"} \quad (1 + \text{inflation rate})^{\text{Year X}}$$

For Year 3 in the project, the adjusted depletion allowance is:

$= \$943 \div (1.042)^3$

$= \$834$

The depletion allowance is calculated on an unadjusted basis for every year and then deflated. If the project ends while a depletion allowance may still be taken, the depletion allowance in that year and subsequent years is termed "surplus depletion" (line 116).

Earnings before interest and taxes (line 104) is defined as the earnings before interest and ODA (line 101) minus the adjusted oil depletion allowance (line 102). For Year 3 of the project, earnings before interest and taxes are \$16,979 - \$834 = \$16,145.

The earnings in line 104 form the basis for Federal income tax. This is calculated in line 105 on the basis of information in line 9 (Federal tax rate). Earnings after taxes are given in line 106.

The project cash flows, line 107, are determined by adding non-cash expenses, depreciation and depletion, to earnings after taxes. The net cash flow for Year 3 is \$10,656 + \$3,233 + \$834 = \$14,723.

The cash flows forecasted for the project may or may not be sufficient to justify continuation of operations. In some circumstances, net cash flows may be positive only because of large values for depreciation, e.g., where large capital expenditures are required on a small project or later in the operating life of the project. Under these circumstances, the project is likely to shut down even though cash flow is positive. Project shutdown is evaluated by the parameter

Project shutdown = Net cash flow (Line 107)
- (tax rate * depreciation and amortization)
(line 9) (line 99)
- (1-tax rate) * (expensed pollution control capital costs)
(line 96)

which calculates the actual cash outlay in that year. If the parameter is equal to or less than zero, the project is assumed to shut down. The model prints a "1" in line 108 for years in which the project operates and a "0" for years in which the project does not operate.

In the event that the project is shut down, certain variables must be recalculated to reflect that decision. Lines 109 through 114 restate production volumes, revenues, and cash flow in light of the shutdown. That is, production and revenues are set to zero after the project shuts down.

Other project variables, such as depreciation, are recalculated because of the earlier shutdown date. Unexpended capitalized costs and surplus depreciation are given in lines 115 and 116.

The income statement for the second and third decades of operation is found on lines 117 through 155 and 156 through 190, respectively.

J.2.6 Summary Statistics

At the end of the project, all costs and revenues are put in present value terms as of the lease year; see lines 191 through 222. Two terms have not been discussed previously. Line 194, expensed investment cash flows, is defined as the sum of the present values for expensed exploration cash flows (line 19) and expensed delineation and development costs (lines 32 and 54) minus the present value of unexpended expensed investment costs. For the project, this is $4,387 + $520 + $14,307 - 0 = $19,214 (note rounding). Line 195, capitalized costs, is the sum of the present values of capitalized exploration costs (line 20) and capitalized delineation and development costs (lines 34 and 55) minus the present value of unexpended capital costs. For the project, this is $587 + $1,088 + $29,934 - $0 = $31,609 (note rounding).

The present value of total company costs is the summation of the present values of the parameters so listed in Table J-3; see line 204. This parameter provides a measure of the present value of net company resources expended in development and operation of petroleum projects. Entries marked with a "plus" in the column contribute to corporate costs. Excess depreciation and surplus depletion lower corporate costs and are therefore marked with a "minus".

Total company costs for oil are the present values for oil royalties and severance taxes and the oil portion of the remaining costs, see line 205), These costs are apportioned by the ratio of oil revenues to total revenues. An analogous procedure is followed to obtain the total company cost for gas (see line 206).

The capital and the annual operation and maintenance costs for incremental pollution control of produced water effluents are put in terms of present value and are annualized over the economic lifetime of the well. The annualized cost is given in line 207.

TABLE J-3

COST AND CASH FLOW USES IN THE MODEL

COST OR CASH FLOW ITEM	USE IN MODEL: COMPANY COST	SOCIAL COST	DEPLETION (COST BASIS)	DEPRECIATION
Leasehold cost	+		+	
G&G expenses		+		
Total capitalized exploration costs				+
Total capitalized delineation costs				+
Total capitalized development costs				+
PV of expensed investment cash flows	+			
PV of capitalized costs	+			
PV of pollution control costs - operations	+	+		
- capital	+			
PV of royalties	+			
PV of severance taxes	+			
PV of operating costs	+	+		
PV of income taxes	+			
PV of excess depletion	-			
PV of surplus depreciation	-			
PV of all investment costs		+		

PV = present value.

Oil and gas production is also discounted to give present value equivalents; see lines 208 through 210. Corporate costs per barrel and corporate costs per Mcf are obtained by dividing the present value of the company cost by the present value equivalent of production (see lines 211 through 213).

The present value of social costs (lines 214 through 216) provides a measure of the value of net social resources expended in the development and operation of offshore petroleum projects. The difference between company cost and social cost is that the social cost ignores the effects of transfers that do not use social resources. The items included in social cost are listed in Table H-3. Social cost per unit of production is obtained by dividing the social cost by the present value equivalent of production, lines 217 through 219.

The net present value of the project, line 220, is calculated as:

$$
\begin{aligned}
\text{Net Present Value} &= \text{PV of Cash Inflows} - \text{PV of Cash Outflows} \\
&= \text{PV of Operating Cash Flows} \\
&\quad - \text{PV of Expensed Investment Cash Flows} \\
&\quad - \text{PV of Capitalized Costs} \\
&\quad - \text{PV of Leasehold Costs} \\
&\quad + \text{PV of Excess Depletion} \\
&\quad + \text{PV of Surplus Depreciation}
\end{aligned}
$$

A positive net present value is indicative of a profitable project at the assumed discount rate, i.e., it generates more revenue than investing the capital in a project with that expected rate of return.

The internal rate of return, line 221, is the rate of return that equates the present value of capital in the exploration and development of the project with the present value of the operating cash flows. An internal rate of return higher than the discount rate is indicative of a profitable project.

The net present value and the internal rate of return are inverse methods of evaluating the profitability of a project. In calculating the net present value, the discount rate is fixed and the net present value may vary. In calculating the internal rate of return, the net present value is set to zero and the discount rate is allowed to fluctuate.

			LINE NO.
Run Date:	08-Feb-90	1986 data	
Project Type:	Gulf 12		
	OIL and GAS		
Lease Bid:	$5,678		1
G&G Expense:	110.50%		2
Leasehold Cost:	$11,952		3
Real Discount Rate:	8.00%		4
Inflation Rate:	4.20%		5
Yrs Btwn Lease Sale & Strt of Exp:	0		6
Percent Costs Expensed:	42.00%		7
Drilling Mud Cost Increment:	$0		8
Corporate Tax Rate:	34%		9

EXPLORATION COSTS

Cost Per Exploratory Well:	$4,355	10
Drilling Mud Cost Increment:	$0	11
Discovery Efficiency:	0.14	12
Platforms per Successful Expl. Wel	4.3	13

	Year 0	Year 1	Year 2	Year 3	
Explor. Costs Per Platform:	$7,234	$0	$0	$0	14
Cost of Successful Efforts:	$1,013	$0	$0	$0	15
Expensed Costs:	$6,647	$0	$0	$0	16
Expensed Cash Flows:	$4,387	$0	$0	$0	17
Capitalized Cash Flows:	$587	$0	$0	$0	18

PV of Expensed Exploration Cash Flows:	$4,387	19
PV of Capitalized Expl. Cash Flows:	$587	20
Total Capitalized Expl. Costs:	$587	21
PV of all Exploratory Costs:	$7,234	22

DELINEATION COSTS

Years Between Start of Expl. and Delineation:	1	23
Number of Delineation Wells Drilled:	2	24
Cost per Delineation Well:	$4,355	25
Drilling Mud Cost Increment:	$0	26
Platforms Per Find:	4.3	27

	Year 1	Year 2	Year 3	Year 4	
Total Delineation Costs:	$2,026	$0	$0	$0	28
Tax Shield:	$289	$0	$0	$0	29
Expensed Cash Flow:	$561	$0	$0	$0	30
Capitalized Cash Flow:	$1,175	$0	$0	$0	31

		LINE NO.
PV Expensed Cash Flow:	$520	32
Total Capitalized Delineation Costs:	$1,175	33
PV of Capitalized Delineation Costs:	$1,088	34
PV of all Delineation Costs:	$1,876	35

CONSTRUCTION COSTS

Total Platform Cost:	$11,660	36
Pollution Control Capital Costs:	$0	37
Yrs btwn Delineation & Constn:	0	38
Number of Wells Drilled:	10	39
Number Wells Drilled Per Year:	6	40
Drilling Cost Per Well:	$4,906	41

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	
Drilling Cost Per Well:	$4,906	$4,906	$4,906	$4,906	$4,906	$4,906	$4,906	$4,906	$4,906	$4,906	42
Drilling Mud Cost Increment:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	43
Well Start:	0	1	2	3	4	5	6	7	8	9	44
Number of Wells Drilled:	0	6	4	0	0	0	0	0	0	0	45
Total Drilling Costs for Year:	$0	$29,436	$19,624	$0	$0	$0	$0	$0	$0	$0	46
Annual Platform Cost:	$11,660	$0	$0	$0	$0	$0	$0	$0	$0	$0	47
Annual Poll Cont Capital Costs:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	48
Total Annual Capital Cost:	$11,660	$29,436	$19,624	$0	$0	$0	$0	$0	$0	$0	49
Tax Shield:	$1,665	$4,203	$2,802	$0	$0	$0	$0	$0	$0	$0	50
Expensed Cash Flow:	$3,232	$8,160	$5,440	$0	$0	$0	$0	$0	$0	$0	51
Capitalized Cash Flow:	$6,763	$17,073	$11,382	$0	$0	$0	$0	$0	$0	$0	52

PV of All Construction Costs:	$51,611	53
PV of Expensed Construction Costs:	$14,307	54
PV of Capitalized Construction Costs:	$29,934	55

FINANCIAL RATES

Percent Water Cut in O&G to Start:	10%								56
Oil/Gas Prod. Decl. Rate/Year (%):	85%								57
Cost Escalator (%):	0%								58
Royalty Rate (%):	22%								59
Federal Tax Rate (%):	34%								60
Average Depreciation Life (years):	7								61
Deprec. rate (subs. years):	14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%	62
State Severance Tax Rate-Oil: (If Alaska enter 99)	6.19%								63
State Severance Tax Rate-Gas: (If Alaska enter 99)	6.19%								64

PRODUCTION COSTS

		NE NO.
Gas Only? (1=yes, 0=no):	0	65
Yrs Btwn Strt Dev & Strt Prod (<5)	2	66
Number of Years at Peak Prod (=>1)	2	67
Oil Peak Prod. Rate/Well(bb):	500	68
Gas Peak Prod. Rate/Well(MMCF/D):	0.835	69
No. of Producing Wells:	10	70
No. of Wells Put in Service/Year:	6	71
Price of Oil Per Barrel:	$23.82	72
Price of Gas Per MCF:	$2.57	73
Total Operating Costs ($000):	$2,312	74
Poll Cont Oper Costs ($000):	$0	75
Days of Production Per Year:	365	76

	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	
OIL PRODUCTION											
Producing Wells:	6	4	0	0	0						77
Barrels of Oil Per Day:	3000	5000	4550	3868	3287	2794	2375	2019	1716	1459	78
Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365	79
Barrels of Oil Per Year:	1095000	1825000	1660750	1411638	1199892	1019908	866922	736884	626351	532398	80
Price/Barrel of Oil:	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	81
GAS PRODUCTION											
MMCF of Gas Per Day:	5	8	8	6	5	5	4	3	3	2	82
MMCF of Gas Per Year:	1829	3048	2773	2357	2004	1703	1448	1231	1046	889	83
Price/MCF of Gas:	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	84
Annual Oil Revenues ($000):	$26,083	$43,472	$39,559	$33,625	$28,581	$24,294	$20,650	$17,553	$14,920	$12,682	85
Annual Gas Revenues ($000):	$4,700	$7,833	$7,128	$6,059	$5,150	$4,377	$3,721	$3,163	$2,688	$2,285	86
Total Revenues ($000):	$30,783	$51,304	$46,687	$39,684	$33,731	$28,672	$24,371	$20,715	$17,608	$14,967	87
Royalty Payments-Oil ($000):	$5,738	$9,564	$8,703	$7,398	$6,288	$5,345	$4,543	$3,862	$3,282	$2,790	88
Royalty Payments-Gas ($000):	$1,034	$1,723	$1,568	$1,333	$1,133	$963	$819	$696	$591	$503	89
Severance Taxes-Oil ($000):	$1,259	$2,099	$1,910	$1,623	$1,380	$1,173	$997	$847	$720	$612	90
Severance Taxes-Gas ($000):	$227	$378	$344	$293	$249	$211	$180	$153	$130	$110	91
ELF for Alaska Sev. Taxes-Oil:	0.25	0.25	0.19	0.10	0.02	ERR	ERR	ERR	ERR	ERR	92
ELF for Alaska Sev. Taxes-Gas:	-2.59	-2.59	-2.95	-3.64	-4.46	-5.43	-6.56	-7.90	-9.47	-11.32	93
Net Revenues ($000):	$22,524	$37,540	$34,162	$29,037	$24,682	$20,979	$17,833	$15,158	$12,884	$10,951	94
Total Operating Costs ($000):	$2,312	$2,312	$2,312	$2,312	$2,312	$2,312	$2,312	$2,312	$2,312	$2,312	95
Exp. Poll.Cont.Cap.Costs ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	96
Poll.Con.Operating Costs ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	97
Capitalized Costs ($000):	$25,598	$11,382	$0	$0	$0	$0	$0	$0	$0	$0	98
Adjstd Deprec & Amort ($000):	$3,233	$6,697	$5,914	$4,053	$2,780	$2,374	$2,280	$1,430	$323	$0	99
Operating Earnings ($000):	$20,212	$35,228	$31,850	$26,725	$22,370	$18,667	$15,521	$12,846	$10,572	$8,639	100
Earnings Before Interest and ODA:	$16,979	$28,531	$25,936	$22,672	$19,590	$16,293	$13,241	$11,416	$10,249	$8,639	101
Adjstd Depletion (Cost Basis):	$834	$1,334	$1,165	$950	$775	$632	$516	$421	$343	$280	102
Surplus Depletion:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	103

											LINE NO.
Earnings Before Int and Taxes:	$16,145	$27,197	$24,771	$21,722	$18,815	$15,661	$12,725	$10,995	$9,906	$8,360	104
Statutory Tax:	$5,489	$9,247	$8,422	$7,386	$6,397	$5,325	$4,327	$3,738	$3,368	$2,842	105
Earnings Before Int After Tax:	$10,656	$17,950	$16,349	$14,337	$12,418	$10,336	$8,399	$7,257	$6,538	$5,517	106
Net Cash Flow:	$14,723	$25,981	$23,427	$19,340	$15,973	$13,343	$11,194	$9,107	$7,204	$5,797	107
Shutoff?	1	1	1	1	1	1	1	1	1	1	108
Actual Oil Prod./Year (Barrels):	1095000	1825000	1660750	1411638	1199892	1019908	866922	736884	626351	532398	109
Actual Gas Prod./Year (MMCF):	1829	3048	2773	2357	2004	1703	1448	1231	1046	889	110
Actual Gross Revenues ($000):	$30,783	$51,304	$46,687	$39,684	$33,731	$28,672	$24,371	$20,715	$17,608	$14,967	111
Actual Net Revenues ($000):	$22,524	$37,540	$34,162	$29,037	$24,682	$20,979	$17,833	$15,158	$12,884	$10,951	112
Actual Net Cash Flow ($000):	$14,723	$25,981	$23,427	$19,340	$15,973	$13,343	$11,194	$9,107	$7,204	$5,797	113
Actual Taxes Paid ($000):	$5,489	$9,247	$8,422	$7,386	$6,397	$5,325	$4,327	$3,738	$3,368	$2,842	114
Capitalized Costs Not Expended:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	115
Surplus Depreciation:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	116

	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	
	OIL PRODUCTION										
Barrels Oil Per Day:	1240	1054	896	761	647	550	468	397	338	287	117
Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365	118
Barrels Oil Per Year:	452539	384658	326959	277915	236228	200794	170675	145074	123312	104816	119
Price Per Barrel:	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	120
	GAS PRODUCTION										
MMCF Gas Per Day:	2	2	1	1	1	1	1	1	1	0	121
MMCF Gas Per Year:	756	642	546	464	395	335	285	242	206	175	122
Price Per MCF:	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	123
Oil Revenues ($000):	$10,779	$9,163	$7,788	$6,620	$5,627	$4,783	$4,065	$3,456	$2,937	$2,497	124
Gas Revenues ($000):	$1,942	$1,651	$1,403	$1,193	$1,014	$862	$733	$623	$529	$450	125
Total Revenues ($000):	$12,722	$10,813	$9,191	$7,813	$6,641	$5,645	$4,798	$4,078	$3,467	$2,947	126
Royalty Payments-Oil ($000):	$2,371	$2,016	$1,713	$1,456	$1,238	$1,052	$894	$760	$646	$549	127
Royalty Payments-Gas ($000):	$427	$363	$309	$262	$223	$190	$161	$137	$116	$99	128
Severance Taxes-Oil ($000):	$520	$442	$376	$320	$272	$231	$196	$167	$142	$121	129
Severance Taxes-Gas ($000):	$94	$80	$68	$58	$49	$42	$35	$30	$26	$22	130
ELF for Alaska Sev. Taxes-Oil:	ERR	ERR	ERR	ERR	ERR	ERR	ERR	ERR	ERR	ERR	131
ELF for Alaska Sev. Taxes-Gas:	-13.49	-16.05	-19.05	-22.59	-26.76	-31.65	-37.42	-44.20	-52.17	-61.56	132
Net Revenues($000):	$9,309	$7,912	$6,726	$5,717	$4,859	$4,130	$3,511	$2,984	$2,537	$2,156	133
Operating Costs:	2312	2312	2312	2312	2312	2312	2312	2312	2312	2312	134
Exp. Poll.Cont.Cap.Costs ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	135
Pollution Control Operating Costs:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	136
For PV Poll. Control:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	137
Adjstd Deprec & Amort ($000):	$0	$0	$0	$0	$0	$0	$0				138
Operating Earnings ($000):	$6,997	$5,600	$4,414	$3,405	$2,547	$1,818	$1,199	$672	$225	($156)	139
Earnings Before Interest and DDA:	$6,997	$5,600	$4,414	$3,405	$2,547	$1,818	$1,199	$672	$225	($156)	140
Adjsted Depletion (Cost Basis):	$228	$186	$152	$124	$101	$82	$67	$55	$45	$37	141
Surplus Depletion:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$37	142
Earnings Before Int and Taxes:	$6,768	$5,414	$4,262	$3,281	$2,446	$1,736	$1,131	$617	$180	($192)	143

											LINE NO.
Statutory Tax:	$2,301	$1,841	$1,449	$1,115	$832	$590	$385	$210	$61	($6[illegible]	[illegible]4
Earnings Before Int After Tax:	$4,467	$3,573	$2,813	$2,165	$1,614	$1,146	$747	$407	$119	($127)	145
Net Cash Flow:	$4,695	$3,760	$2,965	$2,289	$1,716	$1,228	$814	$462	$163	($91)	146
Shutoff?	1	1	1	1	1	1	1	1	1	0	147
Actual Oil Prod./Year (Barrels):	452539	384658	326959	277915	236228	200794	170675	145074	123312	0	148
Actual Gas Prod./Year (MMCF):	756	642	546	464	395	335	285	242	206	0	149
Actual Gross Revenues ($000):	$12,722	$10,813	$9,191	$7,813	$6,641	$5,645	$4,798	$4,078	$3,467	$0	150
Actual Net Revenues ($000):	$9,309	$7,912	$6,726	$5,717	$4,859	$4,130	$3,511	$2,984	$2,537	$0	151
Actual Net Cash Flow ($000):	$4,695	$3,760	$2,965	$2,289	$1,716	$1,228	$814	$462	$163	$0	152
Actual Taxes Paid ($000):	$2,301	$1,841	$1,449	$1,115	$832	$590	$385	$210	$61	$0	153
Capitalized Costs Not Expended:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	154
Surplus Depreciation:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	155

	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	
	OIL PRODUCTION										
Barrels Oil Per Day:	244	207	176	150	127	108	92	78	67	57	156
Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365	157
Barrels Oil Per Year:	89093	75729	64370	54714	46507	39531	33601	28561	24277	20636	158
Price Per Barrel:	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	$23.82	159
	GAS PRODUCTION										
MMCF Gas Per Day:	0	0	0	0	0	0	0	0	0	0	160
MMCF Gas Per Year:	149	126	107	91	78	66	56	48	41	34	161
Price Per MCF:	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	$2.57	162
Oil Revenues ($000):	$2,122	$1,804	$1,533	$1,303	$1,108	$942	$800	$680	$578	$492	163
Gas Revenues ($000):	$382	$325	$276	$235	$200	$170	$144	$123	$104	$89	164
Total Revenues ($000):	$2,505	$2,129	$1,810	$1,538	$1,307	$1,111	$945	$803	$682	$580	165
Royalty Payments-Oil ($000):	$467	$397	$337	$287	$244	$207	$176	$150	$127	$108	166
Royalty Payments-Gas ($000):	$84	$72	$61	$52	$44	$37	$32	$27	$23	$19	167
Severance Taxes-Oil ($000):	$102	$87	$74	$63	$53	$45	$39	$33	$28	$24	168
Severance Taxes-Gas ($000):	$18	$16	$13	$11	$10	$8	$7	$6	$5	$4	169
ELF for Alaska Sev Taxes-Oil:	ERR	ERR	ERR	ERR	ERR	ERR	ERR	ERR	ERR	ERR	170
ELF for Alaska Sev Taxes-Gas:	-72.60	-85.58	-100.86	-118.84	-139.99	-164.87	-194.14	-228.57	-269.09	-316.75	171
Net Revenues($000):	$1,833	$1,558	$1,324	$1,125	$957	$813	$691	$588	$499	$424	172
Operating Costs:	2312	2312	2312	2312	2312	2312	2312	2312	2312	2312	173
Pollution Control Operating Costs:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	174
For PV Poll. Control:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	175
Operating Earnings ($000):	($479)	($754)	($988)	($1,187)	($1,355)	($1,499)	($1,621)	($1,724)	($1,813)	($1,888)	176
Earnings Before Interest and DDA:	($479)	($754)	($988)	($1,187)	($1,355)	($1,499)	($1,621)	($1,724)	($1,813)	($1,888)	177
Adjsted Depletion (Cost Basis):	$77	$65	$55	$47	$40	$34	$29	$25	$21	$18	178
Surplus Depletion:	$77	$65	$55	$47	$40	$34	$29	$25	$21	$18	179
Earnings Before Int and Taxes:	($556)	($819)	($1,043)	($1,234)	($1,395)	($1,533)	($1,650)	($1,749)	($1,834)	($1,905)	180
Statutory Tax:	($189)	($279)	($355)	($419)	($474)	($521)	($561)	($595)	($623)	($648)	181
Earnings Before Int After Tax:	($367)	($541)	($689)	($814)	($921)	($1,012)	($1,089)	($1,154)	($1,210)	($1,258[illegible]	[illegible]

											LINE NO.
Net Cash Flow:	($290)	$476)	($633)	($767)	($881)	($978)	($1,060)	($1,130)	($1,189)	($1,240)	183
Shutoff?	0	0	0	0	0	0	0	0	0	0	184
Actual Oil Prod./Year (Barrels):	0	0	0	0	0	0	0	0	0	0	185
Actual Gas Prod./Year (MMCF):	0	0	0	0	0	0	0	0	0	0	186
Actual Gross Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	187
Actual Net Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	188
Actual Net Cash Flow ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	189
Actual Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	190

PV of Net Revenues:	$152,784	191	PV Equiv. of Oil (bbl):	7,427,539	208
PV of Excess Depletion:	$30	192	PV Equiv. of Gas (MMCF):	12,404	209
PV of Surplus Depreciation:	$0	193	PV BOE	9,611,069	210
PV of Expensed Invest Cash Flows:	$19,213	194	Amortized Company Cost per bbl:	$19.99	211
PV of Capitalized Costs:	$31,610	195	Amortized Company Cost per Mcf:	$2.16	212
PV of Leasehold Cost:	$11,952	196	Amortized Company Cost per BOE:	$18.23	213
PV Poll. Cont. Costs:	$0	197			
PV of Royalties - oil:	$38,923	198	PV of Social Costs - Total:	$86,031	214
PV of Royalties - gas:	$7,013	199	PV of Social Costs - Oil:	$72,896	215
PV of Severance taxes - oil:	$8,542	200	PV of Social Costs - Gas:	$13,135	216
PV of Severance taxes - gas:	$1,539	201			
PV of Income Taxes Paid:	$37,393	202	Amortized Social Cost per bbl:	$9.81	217
PV of Operating Costs:	$19,036	203	Amortized Social Cost per Mcf:	$1.06	218
			Amortized Social Cost per BOE:	$8.95	219
Total Company Costs:	$175,192	204			
Total Company Costs - Oil:	$148,445	205	Net Present Value of Project:	$33,610	220
Total Company Costs - Gas:	$26,747	206	Internal Rate of Return:	0.201	221
Annualized Poll.Cont.Costs:	$0	207	No. of Years of Production:	19	222