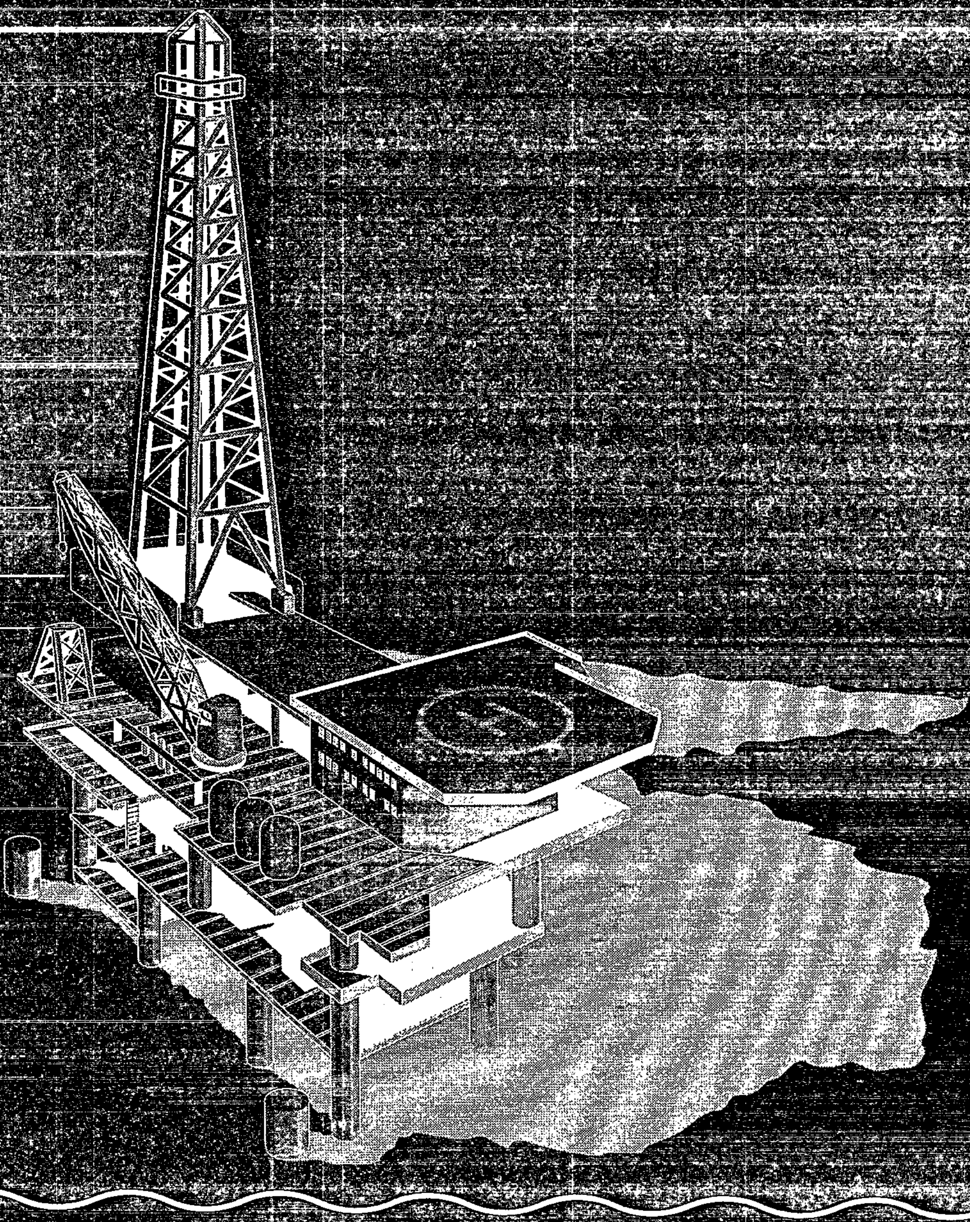
United States
Environmental Protection
Agency

Office of Water
4303

EPA-821-R-96-022
October 1996

EPA

Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category



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CHAPTER ONE

EXECUTIVE SUMMARY

1.1 INTRODUCTION

This final economic impact analysis (FEIA) examines compliance costs and economic impacts resulting from the U.S. Environmental Protection Agency's (EPA's) Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category (Coastal Guidelines) in compliance with Section 301 of the Clean Water Act (CWA). The compliance costs of the final Coastal Guidelines arise from technologies to control several wastestreams: produced water, which is a byproduct of oil production; drill cuttings, which are pieces of rocks and gravel that come up with drilling fluids; drilling fluid and associated effluents; and treatment, workover, and completion (TWC) wastes, which are produced when wells are worked over to keep them productive. The FEIA estimates economic impacts on both the project and firm level in terms of annualized compliance costs; oil and gas production losses; and changes in equity, working capital, and other indicators of financial health. In addition, the FEIA considers impacts on federal and state revenues, national-level output, employment and associated impacts on affected communities, foreign trade, new sources, and small entities.

The total annual compliance costs of the rule are $15.6 million for Best Available Technology (BAT) economically achievable and $0.6 million for New Source Performance Standards (NSPS), for a total cost of $16.2 million. Based on the analyses and results in this FEIA, EPA concludes that effluent limits based on the following BAT technologies are economically achievable: zero discharge of produced water and TWC wastes in the coastal subcategory except for Cook Inlet; discharge limits based on improved gas flotation for produced water in Cook Inlet; and discharge limits (based on offshore limits) for drilling wastes in Cook Inlet. All other waste streams are current practice or are covered by CWA NPDES permits. NSPS are current practice for all but TWC wastes for new and certain recompleted wells in the Gulf of Mexico coastal area.

The impacts evaluated in this FEIA take into account the requirements of EPA Region 6 General Permits for the Coastal Oil and Gas Industry requiring zero discharge of produced water adopted in 1995. Facilities covered by these Permits were not considered to be part of the baseline during the proposal, but are for final rule promulgation. EPA also examines impacts on an alternative baseline, under the assumption that, without the Coastal Guidelines, some operators might receive individual permits allowing them to discharge despite the General Permits. EPA considers this scenario unlikely, but nonetheless presents results of its alternative baseline analysis in Chapter Ten of this FEIA. The remaining chapters of the FEIA describe the different components of the economic analysis. Chapter Two describes data sources; Chapter Three profiles the industry; Chapter Four describes compliance cost estimation and results; Chapter Five presents impacts on production; Chapter Six presents firm-level analysis; Chapter Seven discusses impacts on employment; Chapter Eight summarizes impacts on inflation and balance of trade; Chapter Nine presents an analysis of impacts on new sources; Chapter Ten presents impacts under the assumption of an alternative baseline; and Chapter Eleven presents the Regulatory Flexibility Analysis under the Regulatory Flexibility Act.

1.2 DATA SOURCES

Data sources for this FEIA include: costs for produced water disposal estimated by EPA by permitted discharge facility or platform in Louisiana, Texas, and Alaska; data submittals by firms discharging offshore produced water into major passes of the Mississippi River (Major Pass dischargers) and Cook Inlet firms, and the Section 308 Survey of coastal operators, which is described in more detail in the Economic Impact Analysis for the proposed Coastal Guidelines (PEIA), and information of nonpublic sources such as the Securities and Exchange Commission (SEC), the Bureau of Labor Statistics (BLS), the Bureau of Economic Analysis (BEA), and Bureau of the Census.

1.3 INDUSTRY PROFILE

The coastal oil and gas subcategory is unusual among industry sectors regulated under the CWA because the vast majority of operations are already in compliance with Coastal Guidelines requirements in this rule. For the proposal, EPA considered all coastal operations determined to be discharging produced water and/or TWC wastes in the Louisiana/Texas portion of the Gulf of Mexico by mid-1996 to be affected by the Coastal Guidelines. In early 1995, however, EPA Region 6 promulgated General Permits for produced water, which cover all coastal operations in the Gulf region except for offshore water discharged from a group of operators in the Major Passes of the Mississippi. As a result, most of the Gulf operations affected by the Coastal Guidelines at proposal are already subject to zero discharge requirements for produced water. The rule affects only the Major Pass dischargers and a few operations discharging TWC wastes in the Gulf of Mexico, and all operations in Cook Inlet, Alaska.

The Major Pass dischargers include eight produced water treatment/separation facilities operating under six permits. Current total annual produced water discharge from these facilities is 69.8 million barrels (bbls), with future projections of at least 104.7 million bbls annually. Average daily produced water discharge ranges from 572 to 153,895 bbl per day (bpd). Currently, these facilities service 350 wells, with lifetime production of 600 million total bbls of oil equivalent (BOE).[1] In the future, EPA expects these facilities will serve a much greater number of wells, which would greatly expand their production of produced water.

Thirteen Cook Inlet platforms are currently operating with a total of 224 productive wells, of which 197 are oil wells and 27 are gas wells. Estimated total annual production (1995) is 13.7 million bbls of oil and 140,525 million Mcf (thousand cubic feet) of marketable gas. EPA estimates total lifetime production to be 501.1 million BOE. Over a period of 7 years, producers plan to drill 41 new wells and expect to perform 20 well recompletions.[2] The platforms are served by three land-based and five platform-based separation/treatment facilities. The three

[1] Gas is converted to an oil equivalent in this measure.

[2] See Chapter Two for definition of recompletions.

land-based facilities treat and discharge about 98 percent of all produced water at a rate of about 130,000 bpd.

Firms affected by the Coastal Guidelines include three majors (large, vertically integrated firms) in the Major Pass discharger group; three majors in the Cook Inlet group; and three independents (smaller firms that are not vertically integrated) in the Major Pass discharger group. All of the Major Pass dischargers and Cook Inlet firms that provided financial data are corporations judged to be in adequate to good financial health.

1.4 ECONOMIC IMPACT ANALYSIS METHODOLOGY OVERVIEW AND AGGREGATE COMPLIANCE COST ANALYSIS

The economic impact analysis estimates the following impacts:

- Compliance costs to industry.
- Production losses (in terms of quantities of oil and gas not produced compared to a no-regulation [baseline] scenario).
- Lost economic lifetime (i.e., the loss of productive years associated with wells shutting in earlier under the regulation than under a baseline scenario).
- Numbers of wells, production facilities, or platforms immediately ceasing production as a result of the regulation (first-year shut-ins).
- Losses to operators (in terms of annualized compliance costs and losses in present value of project net worth to the operator [NPV]),[3] state governments, and the federal government.
- Firm-level impacts (firm failure analysis).
- Employment impacts (losses and gains in employment).
- Balance of trade and inflation impacts.
- Impacts on new sources (barriers to entry).

[3]NPV is the total stream of a project's (e.g., platform's or facility's) cash inflows minus cash outflows (operating costs, taxes, and investments) over a period of years (the facility's or platform's lifetime) discounted back to present value.

- Impacts on small businesses (an analysis of whether impacts on small businesses are significant—the Regulatory Flexibility Analysis).

Figure 1-1 shows the types of analyses and how results of one analysis are used as inputs to other analyses.

EPA estimates annualized compliance costs by spreading capital costs over 10 years using a discount rate of 7 percent (in a similar manner to a mortgage). These annualized capital costs are then added to annual operating and maintenance (O&M) costs to compute a total annual compliance cost. The breakdown of capital and O&M costs is presented in EPA's Development Document for this rule.

Table 1-1 presents the annualized compliance costs associated with three produced water/TWC options and two drilling waste options. EPA's selected BAT options are Option #2 for produced water/TWC wastes (zero discharge for all coastal operations, except in Cook Inlet where discharge limitations apply), and Option #1 for drilling waste in Cook Inlet (which is equivalent to current practice). The NSPS option selected for both wastes is identical to those selected for BAT in each region. Costs for the selected BAT options are $15.6 million and for NSPS, $0.6 million, for a total of $16.2 million annually.

TABLE 1-1

TOTAL ANNUAL COSTS FOR ALL SELECTED BAT AND NSPS REGULATORY OPTIONS ($ million 1995)

Type of Waste Stream	Selected Option Number	Aggregate Annual Cost Range (Pre-tax)
Produced water/TWC fluids	Option #2	$15.6
Drilling waste	Option #1	$0
NSPS, produced water/TWC fluids	Option #1	$0.6
Total		$16.2

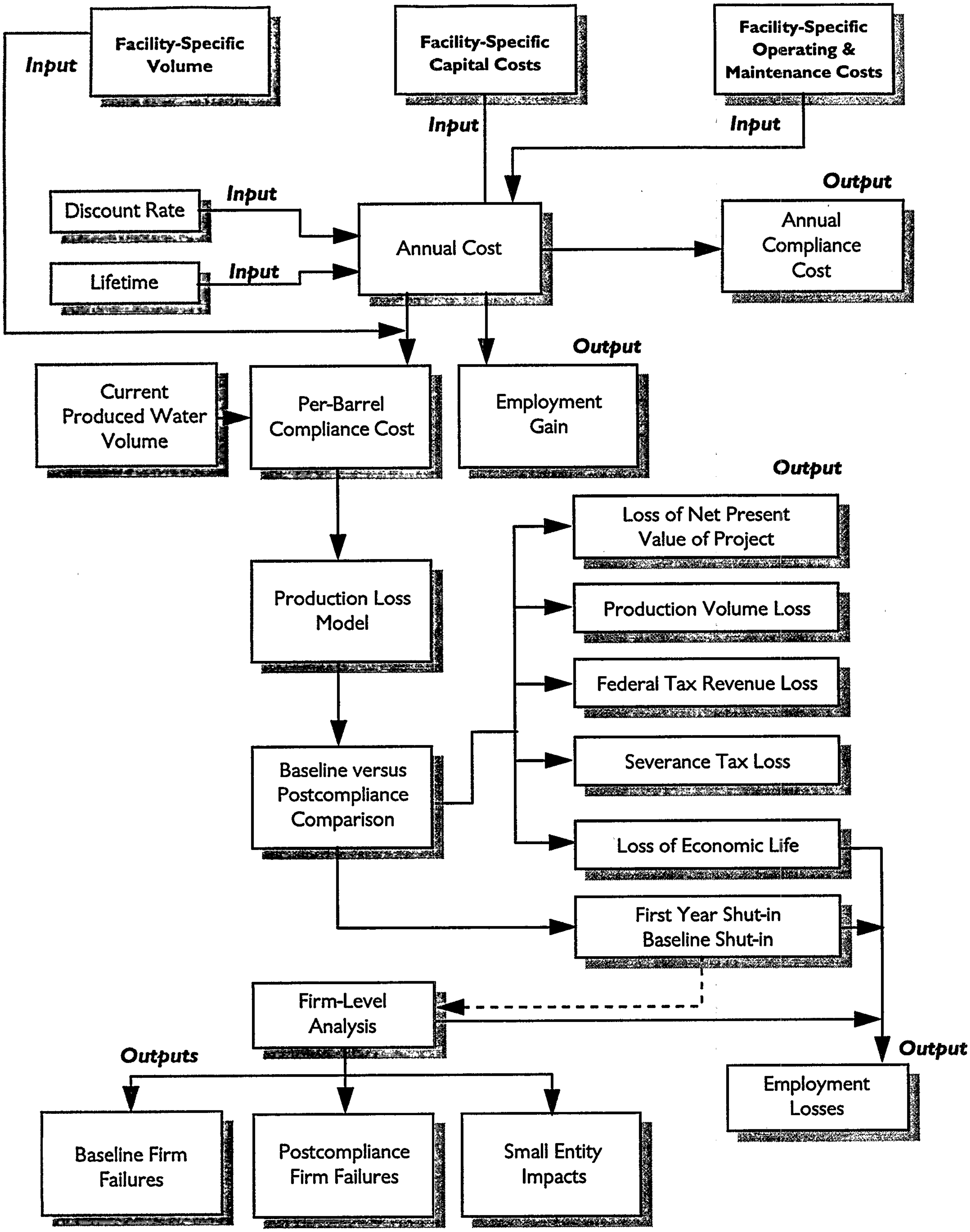

Figure 1-1. Overview of methodology for the economic impact analysis.

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1.5 PRODUCTION LOSS IMPACTS AND OTHER IMPACTS TO PLATFORMS AND FACILITIES

To estimate impacts on discharging Cook Inlet platforms and Major Pass facilities, EPA uses a financial model that simulates the performance and measures the profitability of a petroleum production project. EPA uses data on oil and gas production, expected decline rates, costs of production, royalty rates, severance tax rates, etc., and creates a cash flow statement for the facility or platform for each year of operation. The model makes the facility shut in in the first year that operating costs exceed operating revenues. The model then reports total lifetime production, NPV of project, total royalties, severance tax, and federal tax. EPA then inputs (adds) the capital and operating costs estimated for compliance and reruns the model. The differences between baseline values and post-compliance values are summarized and reported as the impacts of the Coastal Guidelines (see the list in Section 1.4 for a more detailed description of some of the outputs of this model).

Table 1-2 presents the impacts of the selected BAT options on Major Pass facilities and Cook Inlet platforms. Under the selected options, no facilities or platforms would shut in. EPA estimates total maximum impacts as follows: production losses of 5.8 million total BOE, or 0.5 percent of all production in Cook Inlet and the Major Passes or 0.2 percent of all production from coastal oil and gas operations outside of California and North Slope, Alaska; total present value losses of $98.5 million (1.9 percent of the total NPV, taxes, and royalties in Cook Inlet and the Major Passes, or 0.7 percent of the total NPV, taxes, and royalties associated with total coastal production outside of California and North Slope). The latter figure represents losses of $63.7 million in project NPV, $6.1 million in present value severance and state income taxes, $20.3 million in present value federal taxes, and $8.4 million in present value royalties. Disposal of TWC wastes involves negligible additional impacts.

1.6 FIRM-LEVEL ECONOMIC IMPACTS ON THE COASTAL OIL AND GAS INDUSTRY

The firm-level analysis evaluates the effects of regulatory compliance on firms owning one or more affected coastal oil and gas operations. The firm-level analysis identifies impacts not

TABLE 1-2

IMPACTS OF SELECTED OPTIONS (1995 $)

(COOK INLET PLATFORMS AND MAJOR PASS FACILITIES)

Type of Impact	Produced Water Option #2	Drilling Waste Option #1	Total Impacts	Percent of Baseline Lost	Percent of Total Coastal Lost [a]
Number of platforms/facilities shut in	0	0	0	NA	NA
Discounted lifetime production lost (PVBOE)	3,192,814	0	3,192,814	0.4%	0.2%
Total lifetime production lost (BOE)	5,802,808	0	5,802,808	0.5%	0.2%
Present value of project net worth lost (NPV) ($000)	$63,696	$0	$63,696	2.8%	1.4%
Present value of severance and state income taxes lost ($000)	$6,117	$0	$6,117	1.1%	0.3%
Present value of federal income taxes lost ($000)	$20,260	$0	$20,260	1.7%	0.9%
Present value of royalties collected ($000)	$8,449	$0	$8,449	0.7%	0.2%
Total present value losses (including compliance costs) ($000)	$98,522	$0	$98,522	1.9%	0.7%

[a] The calculation of estimates for total Gulf coastal baseline production, NPV, state and severance tax paid, federal tax paid, and royalties is discussed in: Jones, Anne, ERG, Memorandum to Matt Clark, U.S. EPA, dated August 2, 1996, entitled "Approximation of Total NPV, Taxes, Royalties, and Severance in the Gulf Coastal Region (All Operators)."

For this table, Cook Inlet baseline estimates were added to the Gulf estimates. Total coastal figures do not include coastal operations in California or North Slope, Alaska.

Sources: Cook Inlet Dischargers Production Loss Model Runs and Major Pass Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

captured in the production loss analysis. For example, some companies might be too indebted to undertake the investment in the required effluent control, even though the investment might seem financially feasible at the facility or platform level.

EPA's firm-level analysis consists of three steps: a baseline analysis, a screening analysis (which looks at whether annual compliance costs exceed 5 percent of equity and working capital), and a detailed cash flow analysis. In the baseline, EPA considers all firms to be financially healthy. In the screening analysis, annual pollution control costs for one or more firms exceed the 5 percent benchmark for equity and working capital (independents only; majors are unaffected). However, no firms fail a more detailed cash flow analysis. All firms show only small declines in first-year and 10-year present value after-tax cash flow. Furthermore, after more in-depth analysis of credit line availability and capital investment plans, EPA estimates that all firms will be able to raise the necessary capital to meet zero discharge requirements. Thus EPA expects no firm failures as a result of the Coastal Guidelines.

1.7 REGIONAL AND NATIONAL EMPLOYMENT IMPACTS AND TOTAL OUTPUT LOSSES

The employment analysis includes both national- and regional-level analyses. The national-level analysis addresses the Coastal Guidelines' effects on employment and economic output throughout the United States. The regional-level analysis addresses the effects of employment dislocations (layoffs) in the regions where the coastal industry is located, with consideration of those regions where unemployment levels are high and employment is relatively dependent on the coastal oil and gas industry. Employment losses and gains will occur in the industry and throughout the economy in response to the reallocation of expenditures caused by implementation of the Coastal Guidelines. Pollution control expenditures divert investment from oil and gas production, which leads to direct employment losses and oil and gas production losses. These losses are offset by gains in employment in the firms that produce, install, and operate the pollution control equipment.

Four types of changes may occur in employment and output (revenues) as a result of the Coastal Guidelines. Where losses are not offset by gains elsewhere in the economy net or "dead weight" losses occur. These four types of changes, discussed in detail in Chapter Seven, include:

- *Type 1 - Compliance Costs*: Direct oil and gas employment losses due to expenditures diverted to compliance.

- *Type 2 - Production Losses*: Production losses at oil and gas operations that install and operate pollution control equipment.

- *Type 3 - First-year Shut-ins*: Employment and output losses at operations that shut in in the first year and do not install pollution control equipment.

- *Type 4 - Delayed Investment*: Employment and output losses resulting from delayed investment, i.e., where the need for pollution control expenditures delays investment in oil and gas exploration and development.

In general, Type 1 and Type 3 losses are not dead weight losses, but represent transfers or gains to other segments of the economy. However, Type 3 losses may have significant impacts at the regional level. EPA evaluates both direct and indirect employment and output effects at both the national and regional levels, using multiplier analyses appropriate to each of those levels (see Chapter Seven for a detailed description). Nationally, under the selected options, output losses total $20.7 million per year based on direct industry revenue losses of $10.7 million per year. EPA estimates the total annual job loss at 127 jobs per year. Regionally, EPA estimates that employment losses will total 64 jobs annually (included in the national loss estimate) as a result of the selected options. These losses will not have a significant community-level impact. In Cook Inlet under Option #3 for produced water (zero discharge rejected by EPA), however, employment losses would total 108 jobs annually, which would increase the unemployment rate by 0.5 percent. EPA concludes that the impact to Kenai Peninsula Borough is significant under this option because of the borough's higher unemployment (about 13 percent) and dependence on the local oil and gas industry for jobs. The employment impacts contribute to EPA's finding of economic unachievability of zero discharge in Cook Inlet.

1.8 IMPACTS ON THE BALANCE OF TRADE, INFLATION, AND CONSUMERS

The coastal rule may cause a production loss of 5.8 million BOE (see Table 1-2) or 0.4 million BOE per year, which is 0.02 percent of U.S. domestic crude oil production. EPA therefore finds that the change in the balance of trade attributable to the Coastal Guidelines is not significant. Furthermore, since any change in U.S. coastal oil and gas production cannot realistically influence the world price of oil or gas, companies affected by the Coastal Guidelines will be unable to raise prices. Therefore, consumers will not face higher prices as a result of this rulemaking.

1.9 IMPACTS ON NEW SOURCES

EPA has set the selected NSPS and pretreatment standards for new source (PSNS) regulations equal to the selected BAT options for all waste streams with new source requirements. Because new sources will face the same requirements as existing sources, most of which are achieving zero discharge, new operations should face no significant barriers to entry. Furthermore, since EPA has found the BAT requirements are economically achievable, NSPS requirements should be economically achievable as well. EPA conducted a more detailed analysis to determine if NSPS requirements could be a barrier to entry in Cook Inlet, and determined they would not, as they represent at most 2.3 percent of platform construction costs for an industry segment with a 20 to 25 percent targeted rate of return (see Chapter Nine).

1.10 ALTERNATIVE BASELINE SCENARIO

In response to concerns raised in comments on the proposal, this section considers two additional groups of current dischargers and assesses the separate and combined impacts on these groups together with Major Pass and Cook Inlet dischargers, using an alternative regulatory baseline. The two groups, referred to here as the Louisiana Open Bay dischargers and Texas Individual Permit applicants, will be subject to the requirements of the regional permits for produced water. However, to analyze impacts under the alternative baseline, EPA assumes that in the absence of the Coastal Guidelines, the dischargers in these groups will apply for and receive individual permits that allow them to continue to discharge produced water despite the Louisiana state law prohibiting coastal produced water discharge beyond January 1997, and despite the Region 6 General Permits currently applicable to these facilities. EPA believes this alternative scenario to be unlikely.

The Louisiana Open Bay dischargers operate 82 outfalls under 37 permits and represent 22 firms, which have a lifetime production of 103 million total BOE and discharge 120.4 to 180.6 million bbls of produced water annually over the next 10 years. The Texas Individual Permit applicant dischargers (40 firms) have 82 outfalls and have applied for 74 permits serving an estimated 603 wells. Their oil and gas production is estimated at 79 million BOE, and their produced water discharge is estimated at 24.9 to 37.4 million bbls of water annually over the next 10 years. On average, the Louisiana Open Bay dischargers' and Texas Individual Permit applicants' financial indicators are in the acceptable range for financial health and are near the median for comparable measures for the industry as a whole.

Under the assumptions of the alternative baseline, EPA estimates that the annual costs of meeting zero discharge requirements will total $28.1 million for the Louisiana Open Bay dischargers, and $6.1 million for the Texas Individual Permit Applicants. Total BAT costs under the alternative baseline assumptions are $50.3 million BOE.[4] These compliance costs are pretax costs and include costs to install and operate pollution control equipment for baseline and first-year shut-ins, costs which will not be incurred in reality. These costs therefore are an overestimate of impacts on the Louisiana Open Bay dischargers and the Texas Individual Permit applicants.

Under the alternative baseline assumptions, the Coastal rule causes 94 wells, including 47 wells each in the Louisiana Open Bay and Texas Individual Permit categories (see Table 1-3) to shut in in the first year post-compliance. Production losses total 12.8 million BOE, or 7.0 percent of baseline production for the Louisiana Open Bay dischargers and Texas Individual

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[4]The alternative baseline analysis results include impacts resulting from the increased costs to Major Pass dischargers of zero discharge of produced water from coastal wells.

TABLE 1-3

IMPACTS OF PRODUCED WATER OPTIONS (1995 $)

(LOUISIANA OPEN BAY DISCHARGERS AND TEXAS INDIVIDUAL PERMIT APPLICANTS COMBINED)

	Total Louisiana and Texas	
Type of Impact	Baseline Current Practice	Options #1, #2, & #3 Zero Discharge
Projected lifetime discounted production (PVBOE)	127,857,719	120,316,566
Change in discounted production (PVBOE)		7,541,153
Percentage change in discounted baseline production		5.9%
Total projected lifetime production (BOE)	181,614,357	168,845,817
Change in total projected lifetime production (BOE)		12,768,541
Percentage change in total baseline production		7.0%
Present value of project net worth (NPV) ($000)	$861,599	$734,921
Change in NPV ($000)		$126,678
Percentage change in NPV		14.7%
Productive wells in analysis	1,206	1,206
Baseline closures	404	—
Postcompliance closures	—	94
Total production lifetime (years)	11,657	7,045
Change in total production lifetime		4,612
Percentage change		39.6%
Average lifetime (years, among wells not shutting-in in 1st year)	15	10
Change in average lifetime (among wells not shutting-in in 1st year)		5
Percentage change		31.5%
Present value of severance and state income taxes collected ($000)	$211,954	$192,178
Change in present value of severance and state income taxes ($000)		$19,776
Percentage change in severance and state income taxes		9.3%
Present value of federal income taxes collected ($000)	$318,887	$282,139
Change in present value of federal income taxes ($000)		$36,747
Percentage change in federal income taxes		11.5%
Present value of royalties collected ($000)	$293,744	$268,599
Change in present value of royalties ($000)		$25,145
Percentage change in royalties		8.6%

Note: Results are weighted using well survey weights and adjustment factors noted in the text.

Source: Louisiana Open Bay Dischargers and Texas Individual Permit Applicants Production Loss Model Runs (CBI data; in rulemaking record).

Permit applicants. Present value losses in project net worth total $126.7 million (14.7 percent of baseline). These losses include the producers' post-tax share of compliance costs. Other losses include: lost federal income taxes of $36.7 million (11.5 percent), lost state and severance taxes of $19.8 million (9.3 percent), and lost royalties of $25.1 million (8.6 percent). The total present value impacts of the selected options on Louisiana Open Bay dischargers and Texas Individual Permit Applicants under the alternative baseline are estimated to be $208.3 million.

Table 1-4 combines the results of Table 1-3 (Louisiana Open Bays and Texas Individual Permit Applicants) with the impacts on Major Pass and Cook Inlet dischargers, the selected options are associated with 94 wells, but no platforms, shutting in relative to the alternative baseline. Losses under the alternative baseline represent a very small portion of production, revenues, taxes, and royalties for all coastal oil and gas operations in the Gulf of Mexico and Cook Inlet (excluding California and North Slope, Alaska). Under the selected options, lifetime production losses for the alternative baseline groups amount to 0.6 percent of total coastal production. NPV losses represent 4.4 percent of total coastal NPV outside of California and North Slope, Alaska. Other losses, as percentages of all coastal oil and gas operations, are 1.1 percent of severance and state income taxes, 2.5 percent of federal income taxes, and 0.6 percent of royalties.

EPA performed a sensitivity analysis of the results on the Louisiana Open Bay dischargers and Texas Individual Permit applicants using the facility as the unit of analysis.[5] In this analysis, EPA assumed that operators maximize NPV at the facility level. Because many of the marginal wells in EPA's analysis are served by facilities handling very large amounts of production, EPA allocated production costs at marginal wells, and in some cases, compliance costs, on the basis of their share of the facility's production rather than on the average cost per well or proportional to their produced water volumes. This approach approximates the facility-level analyses undertaken for Major Pass and Cook Inlet dischargers. As Table 1-5 shows (in comparison to Table 1-3), losses increase in absolute value, but the percentages of losses decrease, due to the greater amount of baseline production predicted using these alternative

[5]In this facility-level analysis, wells that are baseline shut ins in the well-level analysis stay open, but shut in earlier than they would without the rule, causing a greater loss of production.

TABLE 1-4

IMPACTS OF SELECTED OPTIONS (1995 $)

(COOK INLET PLATFORMS, MAJOR PASS FACILITIES, LOUISIANA OPEN BAY DISCHARGERS, AND TEXAS INDIVIDUAL PERMIT APPLICANTS)

Type of Impact	Produced Water Option #2	Drilling Waste Option #1	Total Impacts	Percent of Baseline Lost	Percent of Total Coastal Lost [a]
Number of platforms/facilities shut in	94 wells	0	94 wells	NA	NA
Discounted lifetime production lost (PVBOE)	10,733,967	0	10,733,967	1.2%	0.6%
Total lifetime production lost (BOE)	18,571,349	0	18,571,349	1.4%	0.6%
Present value of project net worth lost (NPV) ($000)	$199,660	$0	$199,660	6.3%	4.4%
Present value of severance and state income taxes lost ($000)	$26,555	$0	$26,555	3.5%	1.1%
Present value of federal income taxes lost ($000)	$59,674	$0	$59,674	3.9%	2.5%
Present value of royalties collected ($000)	$33,594	$0	$33,594	2.2%	0.6%
Total present value losses (including compliance costs) ($000)	$319,484	$0	$319,484	4.6%	2.1%

[a] The calculation of estimates for total Gulf coastal baseline production, NPV, state and severance tax paid, federal tax paid, and royalties is discussed in:
Jones, Anne, ERG, Memorandum to Matt Clark, U.S. EPA, dated August 2, 1996, entitled "Approximation of Total NPV, Taxes, Royalties, and Severance in the Gulf Coastal Region (All Operations)."
For this table, Cook Inlet baseline estimates were added to the Gulf estimates. Total coastal figures do not include coastal operations in California or North Slope, Alaska.

Source: Cook Inlet Dischargers, Major Pass Dischargers, Louisiana Open Bay Dischargers, and Texas Individual Permit Applicants Production Loss Model Runs (CBI data; in rulemaking record).

TABLE 1-5

IMPACTS OF PRODUCED WATER OPTIONS, RESULTS OF SENSITIVITY ANALYSIS USING ALTERNATIVE COST ALLOCATION ASSUMPTION (1995 $)
(LOUISIANA OPEN BAY DISCHARGERS AND TEXAS INDIVIDUAL PERMIT APPLICANTS COMBINED)

Type of Impact	Total Louisiana and Texas: Baseline Current Practice	Total Louisiana and Texas: Options #1, #2, & #3 Zero Discharge
Projected lifetime discounted production (PVBOE)	157,886,618	149,988,589
Change in discounted production (PVBOE)		7,898,030
Percentage change in discounted baseline production		5.0%
Total projected lifetime production (BOE)	224,114,100	210,315,549
Change in total projected lifetime production (BOE)		13,798,551
Percentage change in total baseline production		6.2%
Present value of project net worth (NPV) ($000)	$1,042,509	$897,965
Change in NPV ($000)		$144,544
Percentage change in NPV		13.9%
Productive wells in analysis	1,206	1,206
Baseline closures	8	—
Postcompliance closures	—	16
Total production lifetime (years)	16,017	10,474
Change in total production lifetime		5,542
Percentage change		34.6%
Average lifetime (years, among wells not shutting-in in 1st year)	13	9
Change in average lifetime (among wells not shutting-in in 1st year)		5
Percentage change		33.8%
Present value of severance and state income taxes collected ($000)	$236,911	$216,922
Change in present value of severance and state income taxes ($000)		$19,989
Percentage change in severance and state income taxes		8.4%
Present value of federal income taxes collected ($000)	$387,548	$346,017
Change in present value of federal income taxes ($000)		$41,531
Percentage change in federal income taxes		10.7%
Present value of royalties collected ($000)	$358,230	$332,472
Change in present value of royalties ($000)		$25,758
Percentage change in royalties		7.2%

Note: Results are weighted using well survey weights and adjustment factors noted in the text.

Source: Sensitivity Analysis of Alternative Cost Allocation Assumption for Louisiana Open Bay Dischargers and Texas In and Texas Individual Permit Applicants.

assumptions. EPA continues to use the results of the more conservative well-level analysis, however, to predict employment impacts.

The results of EPA's firm failure screening analysis (see Section 1.6) shows that 9 firms might experience changes of more than 5 percent in both working capital and equity. Upon further, more detailed, analysis, EPA identified two firms as possible firm failures (all others were baseline failures, or were found not to sustain substantial impacts). The two failing firms either have a very small stake in the wells they operate or have no stake and are operators only. It is possible therefore that little, if any, of the increased costs for operating pollution control equipment would be borne by these firms.

EPA concludes that, under zero discharge and the assumptions of the alternative baseline, a range of 0 to 2 firms might experience firm failure, out of a total of 27 discharging firms examined in this analysis. To account for the number of firms not captured in this analysis, EPA estimates that these 2 firms represent 4 firms in the full universe, yielding a total of 0 to 4 potentially failing firms, which represent 0 to 6.6 percent of all Louisiana Open Bay and Texas Individual Permit operators (61 firms, both large and small), but less than 1 percent of all regulated firms in the Gulf coastal area (417 firms).

EPA estimates national output losses associated with Louisiana Open Bay dischargers and Texas Individual Permit applicants to be $40.6 million. Adding these to Major Pass and Cook Inlet impacts, EPA estimates that total output under the alternative regulatory baseline is reduced by $61.4 million. In addition, EPA estimates that 377 jobs[6] will be lost annually at the national level, which include the regional job losses of 120-139 jobs associated with Louisiana Open Bay dischargers and 54-57 jobs associated with Texas Individual Permit applicants (see Table 1-6).

[6]Totalling regional job losses will not equal job losses at the national level. Some of the national level losses occur outside the affected regions.

TABLE 1-6

ALTERNATIVE BASELINE REGIONAL JOB LOSSES

	Job Losses
Louisiana Open Bay Dischargers	120-139
Texas Individual Permit Applicants	54-57
Total Louisiana Open Bay and Texas Individual Permit	174-196
Major Pass Dischargers	53
Total Gulf	227-249

Regionally, EPA estimates that 174 to 196 jobs are lost annually associated with Louisiana Open Bay dischargers and Texas Individual Permit applicants. Combined with Major Pass losses, up to 249 jobs will be lost per year in the Gulf coastal area. Community-level impacts on the counties, parishes, and boroughs of concern are not significant as the unemployment rates in these areas change by a minuscule percentage.

EPA estimates that the Coastal Guidelines will have no significant effect on trade or inflation under the alternative baseline, for the same reasons that there were no impacts under the current regulatory baseline. The impacts from NSPS requirements are the same as those discussed in Section 1.9 for the current regulatory baseline. Section 1.11 presents the summary of the regulatory flexibility analysis for both baselines.

1.11 REGULATORY FLEXIBILITY ANALYSIS

The RFA as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996, requires the federal government to consider the impacts of proposed regulations on small entities during the rulemaking process. The Administrator has certified that the rule does not have a significant economic impact on a substantial number of small entities.

The Agency has nonetheless prepared a regulatory flexibility analysis equivalent to that required under the Regulatory Flexibility Act.

EPA has determined that under the current regulatory baseline, three small firms will incur compliance costs. None of these firms are likely to fail. Under the alternative baseline assumptions, four small firms are estimated to fail, which is 1 percent of the total 371 regulated small firms in the Gulf of Mexico (86 percent of the coastal industry). The Agency concludes that the rule does not disproportionately affect small firms. EPA also determined that impacts on small local counties and parishes (through losses in royalties), which ranged from $0.12 to $1.3 per person or 0.002 to 0.012 percent, were insignificant.

The analyses contained within this EIA, particularly those discussed in the alternative baseline analysis (Chapter Ten) address issues raised in public comments relating to regulatory flexibility.

EPA determined that less restrictive alternatives to the rule in the Gulf of Mexico would not be acceptable because alternatives allowing discharge would not provide a level playing field among dischargers and nondischargers, nor would it meet the objectives of the Clean Water Act.

CHAPTER TWO

DATA SOURCES

In 1995, EPA proposed Effluent Limitations Guidelines and Standards for the Coastal Subcategory ("Coastal Guidelines") of the oil and gas industry that were projected to affect several hundred operations in coastal Louisiana, Texas, and Alaska. Since that time, however, EPA Region 6, which includes Louisiana and Texas, has issued a General Permit covering produced water and produced sand and requiring zero discharge of these wastes. As a result, the analytical baseline for regulatory analysis has changed substantially since 1995. The General Permit (along with another General Permit for drilling wastes, also in effect) covers nearly all wastestreams and nearly all operations in the Gulf coastal region that were considered affected in the 1995 proposal. The Gulf of Mexico operations that remain unregulated by the General Permit are now limited to a small group that discharge offshore produced water into the major passes of the Mississippi and Atchafalaya Rivers in Louisiana (Major Pass dischargers). Cook Inlet, Alaska, also remains a region where discharge of produced water and drilling wastes is still occurring and thus where additional requirements could have an economic impact.

During proposal development, EPA relied on the Section 308 Survey of coastal operations and firms, which was performed to gather information on the coastal oil and gas industry in Texas, Louisiana, and Alaska. EPA is still relying on some of this survey information, but survey results have been supplemented with more recent information from industry and other sources. Specifics of the Section 308 Survey are discussed in detail in the proposal EIA (PEIA).[1] The PEIA also describes the mapping effort undertaken by EPA to identify the wells and operators to be surveyed, the stratification method, numbers of wells in the Survey universe, and how estimates were made for one group of wells that were not captured by the Survey (those completed prior to 1980). Extrapolation to the "pre-1980" wells is discussed in more detail in

[1]U.S. EPA. 1995. Economic Impact Analysis for Proposed Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. EPA/821/R-95/012. Washington, D.C. February.

Chapter Ten of the current (final) EIA (FEIA), as well. EPA has written this chapter in response to comments on the PEIA from the U.S. Department of Energy (DOE) and the Texas Railroad Commission (RRC).[2] Additional information on statistical extrapolations from the Section 308 Survey can be found in two SAIC reports.[3,4]

In addition to the Section 308 Survey, EPA relies on a number of other information sources, both primary and secondary. Secondary sources include U.S. Department of Energy (DOE) data on 1995 U.S. production, Bureau of Census data on regional employment, Bureau of Economic Analysis (BEA) data on regional input-output multipliers (which show how money flows through the economy), and *Oil and Gas Journal* (OGJ) compilations of the OGJ 200 (which provides financial data on the largest 200 publicly held oil and gas firms in the United States and associated statistics on financial indicators that can be used to judge the financial health of individual firms). Primary sources of information, other than the Survey, include the potentially affected firms and operations in the Gulf and Cook Inlet that provided EPA with industry and firm-level data.

When EPA determined that a subset of oil and gas operators in the Gulf of Mexico might not be covered under the Region 6 General Permit, the Agency undertook an effort to identify potential operators who are:

- Currently discharging.
- Not under a Louisiana Department of Environmental Quality compliance schedule.
- Not subject to Region 6 General Permit requirements because they discharge offshore produced water.

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[2]Chapter Ten presents the results of analyses of an alternative regulatory baseline. The operations analyzed in this alternative baseline analysis are a large portion of those covered in the Section 308 Survey.

[3]SAIC. 1994. Draft Report: Estimation Procedures for the Coastal Oil and Gas Questionnaire. April 12.

[4]SAIC. 1995. Final Report: Statistical Analysis of the Coastal Oil and Gas Questionnaire. January 31.

- Not otherwise planning to cease discharging.

The Agency identified six firms that met these qualifications. These firms voluntarily submitted substantial amounts of data, both as part of comments on the proposal and in response to EPA's further solicitation.[5] This information (including production volumes, costs of production, drilling plans, price of product, royalty rates, severance rates, decline rate, and discount rate) was key to accurately estimating the costs and economic impacts of the Coastal Guidelines on these operations and serves as the basis for many of the cost and impact estimates discussed in subsequent sections of this FEIA.

[5]Major Pass Discharges Data Submittals (CBI data; in rulemaking record).

CHAPTER THREE

INDUSTRY PROFILE

3.1 INTRODUCTION

The Coastal Guidelines establish effluent limitations and standards for produced water; drilling fluids and drill cuttings (drilling wastes); treatment, workover, and completion (TWC) wastes; produced sand; sanitary and domestic waste; and deck drainage. The Coastal Guidelines may result in costs for three wastestreams (produced water, drilling wastes, and TWC), but will not result in costs for the remaining wastestreams. More significantly, the Coastal Guidelines will affect only a small portion of the overall U.S. oil and gas industry.

The coastal oil and gas industry subcategory is unusual because the vast majority of operations are already in compliance with Coastal Guidelines requirements (see discussion below in Section 3.1.2). To reflect this fact, EPA has separated coastal operations into two distinct groups:

- The regulated universe. This universe consists of all coastal operations, the vast majority of which are already in compliance with Coastal Guidelines requirements.
- The affected universe. This universe includes only those operations that are not or will not be in compliance with the Coastal Guidelines by the time they are promulgated.

Section 3.1.1 briefly discusses the regulated universe. This group is described in greater detail in the PEIA. Section 3.1.2 then provides an in-depth discussion of EPA's identification of the affected universe.

3.1.1 The Regulated Universe

The coastal subcategory of the oil and gas industry is defined in 40 CFR Part 405, which states that "coastal" is any facility over "(1) any body of water landward of the territorial seas as defined in 40 CFR Part 125.1(gg) [subsequently revised], or (2) any wetlands adjacent to such waters." According to this definition, any well located in or on a water of the United States landward of the inner boundary of the territorial seas is a coastal subcategory well. In addition, any location in Texas or Louisiana between the Chapman Line (a series of longitudes and latitudes in Southern Louisiana and East Texas) and the inner boundary of the territorial seas is defined as "coastal."[1] Figure 3-1 illustrates the areas in Texas and Louisiana between the inner boundary of the territorial seas and the Chapman Line.

Most of the activity in the coastal subcategory is concentrated in and around the Gulf of Mexico (i.e., the coasts of Alabama, Florida, Louisiana, and Texas); Long Beach, California; and Cook Inlet and the North Slope of Alaska. EPA also investigated industry activity in Mississippi and the Mid-Atlantic region (i.e., along the coasts of Maryland and Virginia). The vast majority of operations in these areas will not be affected by the Coastal Guidelines because, while they will be regulated by the Guidelines, they already meet zero discharge requirements. Therefore, most of these operations will incur no costs for complying with the Guidelines. The operations that will be affected are identified below.

3.1.2 The Affected Operations

EPA's initial investigations, conducted before the Coastal Guidelines were proposed in 1995, indicated that operations in areas beyond Gulf coastal Louisiana and Texas and Cook Inlet, Alaska, would not be significantly affected by the guidelines because they currently meet the Coastal Guidelines requirements. EPA's investigations at that time included assessments of current industry activities and practices in all coastal regions, as well as a review of state

[1]The Chapman Line is defined by points of latitude and longitude within the states of Texas and Louisiana that are explicitly enumerated in the rule.

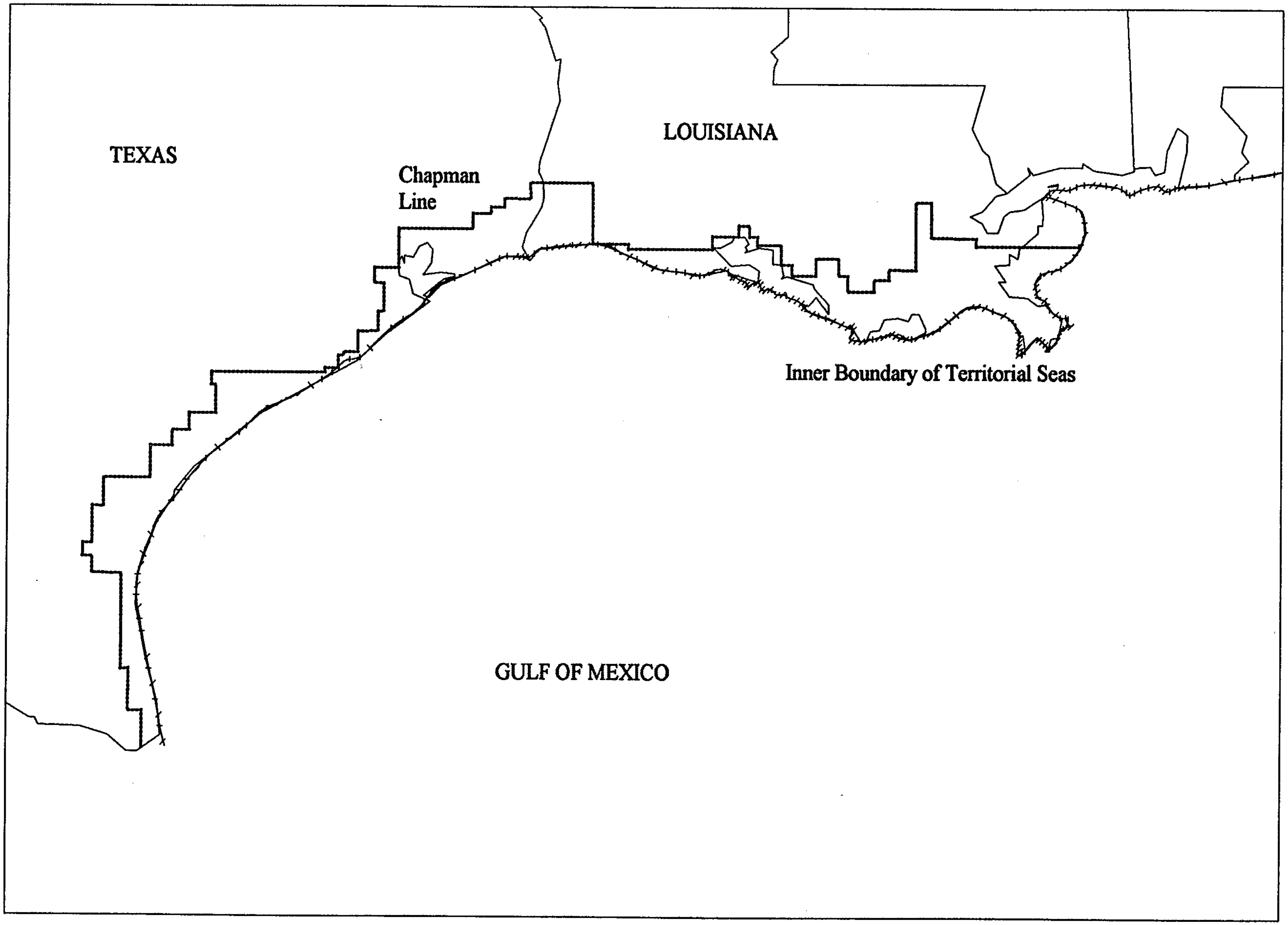

Figure 3-1. Location of the Gulf of Mexico coastal region in Texas and Louisiana.

regulations concerning the discharge of wastes from oil and gas operations. EPA concluded that coastal subcategory operations in some regions would not be affected by the Guidelines, based on the following findings:

- **Coastal Alabama.** As of 1993, about 15 wells were thought to be operating in this area. As of May 25, 1994, the discharge of drilling fluids and cuttings was prohibited. Also, a state law requires that produced fluids be injected.[2,3]

- **Coastal Florida.** In 1994, about 41 producing wells in this area were considered coastal operations and approximately two additional wells were being drilled each year. Nonetheless, all operators inject their produced water; reuse their drilling fluids, inject them annularly, or leave them in a dry wellbore; and either dispose of cuttings in reserve pits or haul them off site to a landfill.[4]

- **Coastal Mississippi.** None of the wells operating in Mississippi meet the definition of coastal operations, and all well operators are required by state law to inject their produced water.[5] No new wells are slated to be drilled in the coastal region for the foreseeable future.[6]

- **Long Beach, California.** Oil and gas production in this area is restricted to four manmade islands in San Pedro Bay.[7] As of 1993, 586 wells were operated in this area, and six to seven new wells were being drilled each year. All produced water is injected, primarily for waterflooding (see Section 3.2), and no drilling fluids or cuttings are being discharged.

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[2]Murphy, Matt, ERG, Memorandum to Allison Wiedeman, U.S. EPA, dated June 1, 1993, entitled "Well Status Updates for Alabama, Florida, and Mississippi."

[3]Wiedeman, Allison, U.S. EPA, Memorandum to file, dated September 6, 1994, entitled "Coastal Oil and Gas Activity in California, Alabama, Mississippi, and Florida."

[4]Ibid.

[5]Murphy, Matt, ERG, Memorandum to Allison Wiedeman, U.S. EPA, dated June 1, 1993, entitled "Well Status Updates for Alabama, Florida, and Mississippi."

[6]Murphy, Matt, ERG, Memorandum to Allison Wiedeman, U.S. EPA, dated June 1, 1993, entitled "Well Status Updates for Alabama, Florida, and Mississippi."

[7]Ibid.

- **North Slope, Alaska.** About 2,085 producing wells are operating on Alaska's North Slope, and about 106 additional wells are drilled annually. No drilling or production waste is discharged in this area.[8]

- **The Mid-Atlantic.** Currently this area is not the site of any oil and gas production. Moreover, no such activity is likely to be initiated within the next 15 years. Should any activity commence, operators would be unlikely to be allowed to discharge wastes, according to state officials.[9]

These areas are not discussed in detail in this FEIA. Furthermore, only a subset of the coastal oil and gas operations in Louisiana and Texas might be affected by the final Coastal Guidelines.

For the proposal, EPA considered all coastal operations in the Louisiana/Texas portion of the Gulf of Mexico that were then determined to be discharging produced water to be affected by the Coastal Guidelines (see the PEIA). In early 1995, however, EPA Region 6 promulgated a General Permit for produced water,[10] which joined the General Permit for drilling waste disposal[11] from coastal operations already in effect. These two General Permits cover nearly all coastal operations and nearly all wastes in the Gulf coastal region, except for TWC wastes. Thus, most of the Gulf operations considered affected for the proposal have become subject to zero discharge. At the same time, EPA Region 6 issued Administrative Orders allowing until January 1997 to continue zero discharge of produced water. Thus, for purposes of assessing the economic impacts of this rule, under the current regulatory baseline, these facilities are considered to be meeting zero discharge.

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[8]U.S. EPA. 1994. "Trip Report to Cook Inlet, Alaska, and North Slope Oil and Gas Facilities, August 25-29, 1993." August 31.

[9]Murphy, Matt, ERG, Memorandum to Allison Wiedeman, U.S. EPA, dated July 1, 1994, entitled "Coastal Oil and Gas Activity in the Atlantic Region."

[10]60 *Federal Register* 2387 (January 9, 1995). Final NPDES General Permits for Produced Water and Produced Sand Discharges From the Oil and Gas Extraction Point Source Category to Coastal Waters in Louisiana (LAG290000) and Texas (TXG290000).

[11]58 *Federal Register* 49126 (September 21, 1993). Final NPDES General Permits for the Coastal Waters of Louisiana (LAG330000) and Texas (TXG330000).

This profile and Chapters Four through Nine therefore discuss only one group of operations in the Gulf of Mexico region, i.e., operations discharging offshore water to the major deltaic passes of the Mississippi River and Atchafalaya River (Major Pass dischargers[12]). Only Coastal Guidelines requirements for TWC wastes will potentially affect some operations in the broader Gulf coastal group.[13] For a profile of this broader group of coastal operations, see the PEIA.

The Major Pass dischargers are only partially represented in the Section 308 Survey. Moreover, although a small fraction of the oil and gas production and therefore produced water in this group is from coastal wells, most is from offshore operations. The group is thus distinguished from all other coastal operations in that its produced water discharges are primarily from offshore operations. These operations discharge offshore produced water (commingled in some cases with coastal produced water) to the coastal region and are not covered by the General Permit for produced water nor by any other NPDES permit. The Section 308 Survey did not account for the offshore production and surveyed very few of the Major Pass dischargers. Therefore, as noted in Chapter Two, EPA has relied primarily on voluntary data submissions from these operators to define and profile the Major Pass discharging operations.

In addition to the Major Pass dischargers, this profile also discusses the group of dischargers located in Cook Inlet, near Anchorage, Alaska, and the Kenai peninsula. EPA Region 10 has issued a notice of a draft General Permit for drilling and production wastes in this

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[12]EPA found no operations discharging offshore water to the Atchafalaya River (see EPA's Development Document for this Rulemaking: U.S. EPA. Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. September 1996).

[13]Chapter Ten of this FEIA presents an additional profile and economic impact analysis of a subset of the Louisiana and Texas coastal operations. EPA includes this chapter to address comments from the Texas Railroad Commission and DOE. To respond to these comments, EPA has performed an impact analysis using an alternative regulatory baseline in which certain operations in Texas and Louisiana, principally those in open bays, are assumed to be eligible for individual permits, which would allow them to continue to discharge in the absence of the Coastal Guidelines. Although EPA considers it likely that many of these operations would achieve zero discharge even without the Coastal Guidelines in place, it has undertaken a conservative impact analysis of this alternative baseline.

region,[14] but, since no final permit has been promulgated, these operations also are considered potentially affected by the Coastal Guidelines.

The following sections profile each of the groups of regulatory concern. The profile covers wells, treatment facilities, and firms operating in the Gulf and Cook Inlet, broken down by group of concern: Major Pass dischargers and Cook Inlet operations. Section 3.2 presents a brief description of the process of oil and gas extraction, including how wells are drilled, how oil and gas is produced, and what wastes are generated during these processes. Section 3.3 presents a general overview of the industry in the two key regions, discussing the characteristics of the wells, facilities, and/or platforms among Major Pass and Cook Inlet discharging operations and describing the types and nature of the firms owning and operating coastal oil and gas production wells and facilities in the key coastal regions.

3.2 THE PROCESS OF OIL AND GAS EXTRACTION AND THE WASTES GENERATED

Two activities in the oil and gas extraction process generate the major portion of wastes in this industry: drilling activities and production activities. This section presents a summary of these activities and related wastes, including miscellaneous wastes, which are small volume wastes associated indirectly with drilling or production operations. The major source for the information in this discussion is EPA's Development Document[15] for this rulemaking.

3.2.1 Drilling Operations

The drilling operations of particular concern in this analysis are those performed in Cook Inlet, Alaska. Currently all other drilling activities in the coastal subcategory do not discharge

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[14]60 *Federal Register* 48796 (September 20, 1995). Alaskan Outer Continental Shelf; Draft National Pollutant Discharge Elimination System General Permit.

[15]U.S. EPA. 1996. Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. Washington, D.C. September.

drilling fluids and cuttings, because of either state or federal requirements or operator preference.

The two types of drilling operations conducted as part of the oil and gas extraction process are exploratory and developmental. Exploratory operations involve drilling wells to determine potential hydrocarbon (oil and gas) reserves. Once a hydrocarbon reserve has been discovered and delineated, development wells are drilled for production. Although the rigs used for each type of drilling can differ, the drilling process is generally the same.

In the initial phases of exploration, shallow wells usually are drilled to discover the presence of oil and gas reservoirs. Subsequently, deeper wells are drilled to establish the extent of a reservoir. Exploration activities are usually of short duration, involve a small number of wells, and are conducted from mobile drilling rigs.

In Cook Inlet, exploratory drilling is typically conducted from jackup rigs, which are barge-mounted rigs with extendable legs that are retracted during transport. At the drill site, the legs are extended to the floor of the waterbody, gradually lifting the barge hull above the water. Some exploratory drilling has been performed in recent years in Cook Inlet as part of ARCO's Sunfish Field exploration.[16]

Development drilling is conducted to begin extraction of recently discovered reserves of hydrocarbons; it is also conducted to increase production or to replace nonproducing wells on existing production sites. Since development wells tend to be smaller in diameter than exploratory wells, less waste is generated.

Two commonly used types of drilling rigs for development drilling are the platform rig and the mobile drilling unit. In Cook Inlet, once exploratory drilling has confirmed that an extractable quantity of hydrocarbons exists, the producer constructs a platform at that site for drilling and production operations. Development wells are often drilled from these platforms.

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[16]"Cook Inlet Maintaining Oil Flow in Spite of Budget Restrictions," Oil and Gas Journal (OGJ), June 20, 1994, pp. 21-23.

Also, the producer frequently conducts directional drilling from a fixed location such as a platform to access different parts of a geological formation. This type of drilling involves drilling the top part of the well straight down and then directing the wellbore to the desired location. The last platform constructed in Cook Inlet was built in the mid-1980s,[17] and even with the exploratory drilling that took place in the Sunfish Field a few years ago, EPA anticipates no additional platform construction.[18]

The type of drilling used in Cook Inlet is rotary drilling. This method uses a rotating drill bit attached to the end of a drill pipe, referred to as the "drill string." With this method, the walls of the hole tend to cave in as the wellbore deepens; thus, periodically the drill string must be lifted out so that a casing, which is a tube-shaped liner, can be placed in the hole. Cement then is pumped into the space between the casing and the hole wall to secure the casing. Each new portion of casing must be smaller in diameter than the previous portion to allow for installation. The process of drilling and adding sections of casing continues until final well depth is reached.

Rotary drilling relies on circulating drilling fluid to move drill cuttings (bits of rock) away from the bit and out of the borehole. The drilling fluid, or mud, is a mixture of water, special clays, and certain minerals and chemicals that is pumped "downhole" through the drill string and ejected through the nozzles in the drill bit at high speeds and pressure. The jets of drilling fluid lift the cuttings from the bottom of the hole and away from the bit so that the cuttings do not interfere with the effectiveness of the drill bit. The drilling fluid circulates and rises to the surface through the space between the drill string and the casing, called the annulus. At the surface, the cuttings, along with silt, sand, and any gases, are removed from the drilling fluid before the drilling fluid is returned downhole to the bit. The cuttings, silt, and sand are separated from the drilling fluid by a solids separation process typically involving shale shakers, desilters, desanders, and centrifuges (each removing sequentially smaller waste particles from the

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[17]Marathon/Unocal. 1994. "Zero Discharge Analysis: Cook Inlet, Alaska." Marathon Oil Company and Unocal Corporation. March.

[18]Wiedeman, Allison, U.S. EPA, Personal communication with Jim Short, ARCO, dated May 9, 1994, regarding ARCO's future drilling activity in Cook Inlet—status of ARCO's Sunfish operations in Cook Inlet, Alaska.

drilling fluid). Some of the drilling fluid remains with the cuttings after solids separation.[19,20] In Cook Inlet, if the cuttings, silt, sand, and residual drilling fluid do not contain free oil or other regulated contaminants, they are discharged into the inlet.

Drilling fluid can become contaminated, and thus constitute a waste, during several different stages of the drilling process. Drilling fluid also can become waste if it cannot be adjusted to provide the appropriate lubrication (lubricity) for drilling at different formation pressures (which vary at different depths). When a drilling fluid no longer meets the requirements for lubricity, density, viscosity, or gel strength, for example, a "mud changeover" must be performed. The drilling fluid system replaced can become a waste at this stage if it is not recycled or reused later in the drilling process.

Similarly, if drilling fluid solids cannot be controlled efficiently, dilution with fresh drilling fluids might be necessary to reduce the solids content of the circulating drilling fluid system, in which case the displaced drilling fluid can become a waste. The more recently developed solids control systems are much more efficient than those used in the past; thus, this type of waste drilling fluid is now less of a problem.

Most drilling fluid systems are water based. Although oil-based systems are less common than they once were, some use of oil (or synthetic) additives is still necessary under special circumstances, such as when performing directional drilling or when freeing a stuck pipe. Thus, some portion of the drilling fluids used in Cook Inlet might not meet a more stringent toxicity limit due to the occasional use of specialized fluids.

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[19]Ray, J.P. 1979. "Offshore Discharges of Drill Cuttings." Outer Continental Shelf Frontier Technology. Proceedings of a Symposium. National Academy of Sciences. December 6. (Offshore Rulemaking Record, Vol. 18.)

[20]Meek, R.P., and J.P. Ray. 1980. "Induced Sedimentation, Accumulation, and Transport Resulting from Exploratory Drilling Discharges of Drilling Fluids and Cuttings on the Southern California Outer Continental Shelf." Symposium—Research on Environmental Fate and Effects of Drilling Fluids and Cuttings. Sponsored by API, Lake Buena Vista, Florida. January.

The most significant waste streams in Cook Inlet, in terms of volume and particular constituents associated with drilling activities, are drilling fluids and drill cuttings. Drill cuttings are generated throughout the drilling project, although higher quantities of cuttings are generated when drilling the first few thousand feet of the well because the borehole is the widest during this stage. In contrast, the largest quantities of excess drilling fluids are generated as the project approaches final well depth. Most waste fluid is generated at completion of well drilling because the entire drilling fluid system must be removed from the hole and the tanks used to hold the drilling fluid must be emptied. Some constituents of the drilling fluid can be recovered after completion of the drilling, either at the rig or by the supplier of the drilling fluid. When drilling is continuous, which can be the case on the multi-well Cook Inlet platforms, drilling fluid can be reused to drill the next well in a series.

A much smaller waste stream associated with the drilling process is drainage from deck platforms during drilling, which can occur during rainstorms. In Cook Inlet, deck drainage is combined with produced water.[21]

3.2.2 Production Activities

When the drilling process is completed (in either the Gulf or Cook Inlet), successful wells begin to produce reservoir fluids, which consist of oil, natural gas liquids or condensate, and salt water (sometimes dry gas also is produced). The salt water contains dissolved and suspended solids, hydrocarbons, and metals and might contain small amounts of radionuclides. Portions of the salt water also can include enhanced oil recovery (EOR) fluids, which are gases or liquids injected downhole to produce additional reservoir pressure. As hydrocarbons are produced, the natural pressure in the reservoir decreases and additional pressure must be added to the reservoir to continue production of the fluids. When a liquid is used, the process is called waterflooding.

[21]SAIC. 1994. Oil and Gas Exploration and Production Handling Methods in Coastal Alaska.

EOR processes are divided into three general classes: thermal, chemical, and miscible displacement. In the thermal process, steam generally is used to aid in removing hydrocarbons from the geological formation. Chemical EOR processes use surfactants, polymers, and/or caustics for washing oil from the formation and driving or displacing oil into the wellbore. In miscible displacement, kerosene or gas, and then water, are used first to dissolve and then to drive oil from the formation. Typically EOR fluids are a part of the produced water stream.

As they surface, the gas and oil (including EOR fluids) are separated for further processing and sale. Typically, a series of vessels is used for the separation process. The major waste streams associated with this process are produced water and, to a much lesser extent, produced sand, which is, in part, made up of fine particles that are entrained with the oil and produced water. Section 3.3.1 presents more details on the equipment and processes used to separate and treat produced water in both the Gulf and Cook Inlet.

3.2.3 Miscellaneous Wastes

Other wastes besides the drilling and produced water wastes discussed above also can be generated during the productive life of a well. Produced sand and deck drainage associated with drilling are discussed above. Small volumes of production deck drainage and domestic and sanitary wastes might also be generated, although deck drainage is generated only if a platform is present, and sanitary and domestic wastes are generated only if toilet or washup facilities are on site. The most common miscellaneous wastes are known as treatment, workover, and completion (TWC) wastes. This section focuses on the processes that generate these wastes.

Treatment. Well treatment is the process of stimulating a producing well to improve oil or gas productivity. Two basic methods of well treatment include hydraulic fracturing and acid treatment. Hydraulic fracturing is typically used on sandstone, and acid treatment is generally performed on formations of limestone or dolomite.[22] Hydraulic fracturing, in which a fluid is

[22]Walk, Haydel and Associates. Undated. Industrial Process Profiles to Support PMN Review: Oil Field Chemicals. Prepared for U.S. EPA. Received by EPA June 24, 1983. (Offshore Rulemaking Record, Vol. 26.)

pumped into the formation under high pressure, relies on inert materials known as proppants (e.g., sand, walnut shells, aluminum spheres, glass beads) that remain in the formation to prop the channels open after the fluid and pressure have been removed.[23,24] This method of well treatment is rarely used in the Gulf of Mexico.

Acid stimulation involves injecting acid solutions into the geological formation. The two types of acid treatment used are acid fracturing and matrix acidizing. In acid fracturing, the acid solution is injected under high pressure. The acid solution both dissolves the formation rock and fractures it. Matrix acidizing uses low pressures to avoid fracturing. Other chemical treatments sometimes used include treatment with organic solvents, such as xylene or toluene, to remove paraffins or asphalts that block the wellbore.

Not all residuals from these well treatments become wastes. Many are recycled to be used in other well treatment fluids. Nonetheless, some become part of the produced water stream and are subsequently discharged (such as in Cook Inlet) or injected with produced water, and some are disposed of separately from produced water.

Workover. Waste fluids can also be generated when a well undergoes a workover to improve or restore productivity, repair or replace downhole equipment, evaluate the rock formation, or abandon a well. Workovers are generally performed every 3 to 5 years.[25,26] Responses to EPA's Section 308 Survey indicate, however, that workovers in the Gulf of Mexico

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[23]Walk, Haydel and Associates. Undated. Industrial Process Profiles to Support PMN Review: Oil Field Chemicals. Prepared for U.S. EPA. Received by EPA June 24, 1983. (Offshore Rulemaking Record, Vol. 26.)

[24]U.S. EPA. 1987. Report to Congress: Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy, Vol. 1. EPA/530/SW-88/003. December. (Offshore Rulemaking Record, Vol. 119.)

[25]American Petroleum Institute (API). 1988. Exploration and Production Industry Associated Wastes Report. Washington, D.C. May.

[26]American Petroleum Institute (API). 1991. Detailed Comments on EPA Supporting Documents for Well Treatment and Workover/Completion Fluids. Attachment to API comments on the March 13 proposal. May 13. (Offshore Rulemaking Record, Vol. 146.)

occur once per year on average (Section 308 Survey). Workovers generate some of the same wastes as those generated during well treatment and completion operations because some of the operations are the same (e.g., stimulation, reperforation, casing repair, replacement of subsurface equipment).[27,28,29]

Completion. Completion operations include the setting and cementing of the production casing, packing the well, and installing the production tubing. All completion methods consist of four steps: wellbore flush, production tubing installation, casing perforation, and wellhead installation.

During the initial wellbore flush, a slug of fluids is injected into the casing. These cleaning or preflush fluids can be circulated and filtered many times to remove solids from the well and to minimize potential damage to the geological formation.[30] Once the well has been cleaned, a second completion fluid (i.e., a "weighting fluid") is injected. This fluid maintains sufficient pressure to prevent the formation fluids from migrating into the hole before well completion is finished.

Next, production tubing is installed inside the casing using a packer which is placed at or near the end of the tubing. The packer consists of pipe, gripping elements, and sealing elements. When the tubing is in place, the packer traps completion fluids between the casing and the production tubing. These "packer fluids" provide long-term protection against corrosion.

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[27]Walk, Haydel and Associates. Undated. Industrial Process Profiles to Support PMN Review: Oil Field Chemicals. Prepared for U.S. EPA. Received by EPA June 24, 1983. (Offshore Rulemaking Record, Vol. 26.)

[28]Acosta, D. 1981. "Special Completion Fluids Outperform Drilling Muds." Oil and Gas Journal. March 2. (Offshore Rulemaking Record, Vol. 25.)

[29]American Petroleum Institute (API). 1988. Exploration and Production Industry Associated Wastes Report. Washington, D.C. May.

[30]Wiedeman, Allison, Project Officer, U.S. EPA, Memorandum to Marv Rubin, Branch Chief, U.S. EPA, dated January 22, 1992, entitled "Supplementary Information to the 1991 Rulemaking on Treatment/Workover/Completion Fluids."

Typically packer fluids are mixtures of a polymer viscosifier, a corrosion inhibitor, and a high-concentration salt solution,[31] and can be removed during workover operations.[32]

Following installation, the production tubing is perforated to allow hydrocarbons to flow from the reservoir into the wellbore. For this step, a special gun is used to fire bullets or charges that penetrate the casing and cement. Alternatively, a small perforated pipe can be hung from the bottom of the casing.[33,34]

The final step calls for installation of the "Christmas tree," a device that controls the flow of hydrocarbons from the well. When the valves of the Christmas tree are initially opened, the completion fluids remaining in the tubing are removed before fluid from the formation begins to flow.

3.3 GENERAL OVERVIEW OF THE COASTAL SUBCATEGORY INDUSTRY

Wells, platforms, produced water treatment/separation facilities, and firms are used as units of analysis in this FEIA. Unlike wells in the offshore subcategory or in Cook Inlet, few Gulf of Mexico region wells are located on multi-well platforms. Furthermore, the multi-well

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[31]Gray, G.R., H. Darley, and W. Rogers. 1980. Composition and Properties of Oil Well Drilling Fluids. January.

[32]Arctic Laboratories Limited et al. 1983. Offshore Oil and Gas Production Waste Characteristics, Treatment Methods, Biological Effects, and Their Applications to Canadian Regions. Prepared for Environmental Protection Services. April. (Offshore Rulemaking Record, Vol. 110.)

[33]Baker, R. 1985. A Primer of Offshore Operations. Second edition. Petroleum Extensive Service, University of Texas at Austin.

[34]Radian Corporation. 1977. Industrial Process Profiles for Environmental Use. Chapter 2: Oil and Gas Production Industry. EPA/600/2-77/023b. February. (Offshore Rulemaking Record, Vol. 18.)

platforms operating in the Gulf coastal area appear to have fewer than four wells on them.[35] EPA selected wells in certain Gulf of Mexico operations as principal units of analysis for determining production loss and economic life (see Chapter Ten). In some cases, however, where large central treatment facilities or multi-well platforms are the rule, the platform or treatment facility becomes the primary unit of analysis. EPA therefore uses well-based parameters (and variables) to model the economic viability of Gulf oil and gas production activities associated with the alternative analytical baseline (see Chapter Ten), but the platform is the unit of analysis for Cook Inlet and the treatment/separation facility is the unit of analysis for the Major Pass dischargers (see Chapter Five for key parameters and variables for Major Pass discharging facilities and Cook Inlet platforms). The following section discusses wells, platforms, and treatment/separation facilities; firms are discussed later in Section 3.3.2.

3.3.1 Wells, Platforms, Treatment Facilities, and Production in the Coastal Region

Major Pass Dischargers

Major Pass dischargers are characterized primarily by their treatment facilities (discussed below). Although information obtained on numbers of wells per facility was not complete for all operators, EPA estimates that, at a minimum, the Major Pass facilities service 350 wells (see EPA's Development Document). The Agency further estimates that lifetime production associated with these wells (using the production loss model described in Chapter Five) totals 435 million barrels of oil equivalent in present value terms (PVBOE), or 600 million total BOE (undiscounted).[36] Note that these baseline production figures include production expected from planned drilling in this region of the Gulf over the next 5 years. Based on discussions with the Major Pass discharging operators, EPA expects the Major Pass discharging operations to make

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[35]Kaplan, Maureen, ERG, Memorandum to Neil Patel, U.S. EPA, dated February 11, 1994, entitled, "Stand-alone Projects: ERG Multi-Well Structures and Single-Well Structures in the 308 Survey Data."

[36]See Chapter Five, Table 5-5. Source: Major Pass Dischargers Production Loss Model Runs. (Confidential business information [CBI] contained in rulemaking record only.)

substantial additions to production through drilling new wells over the next 5 years, in some cases doubling total production each year.[37]

Unlike other industries, wastewater generation in the oil and gas production industry is not proportionate to the quantity of materials processed. Produced water can constitute from 2 to 98 percent of the fluid production at a given facility (see EPA's Development Document; information in this subsection is summarized from this document unless otherwise noted). In general, the proportion of hydrocarbons to produced water tends to be high during the initial production phase and to decrease as hydrocarbons are depleted. Thus, any regulation affecting the cost of produced water disposal will tend to affect the older, more marginal fields more than the newer developmental projects.

Currently, typical produced water treatment facilities in the Gulf of Mexico are designed to meet best practicable technology (BPT) requirements, which restrict the oil and grease concentrations of produced water to a maximum of 72 milligrams per liter (mg/L) for any one day and to a 30-day average of 48 mg/L. Technologies and practices used to achieve this level of control include:

- Equalization (surge tank, skimmer tank)
- Chemical addition (feed pumps)
- Oil and/or solids removal
- Gravity separators
- Flotation
- Filters
- Plate coalescers
- Filtration prior to injection
- Subsurface disposal (injection)

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[37]Major Pass Dischargers Data Submittals (CBI data; in rulemaking record).

The typical Gulf Coast discharging facility uses gravity separators, which are tanks large enough to store oil and water mixtures for a sufficient length of time to allow the mixture to separate. Chemicals might be added to hasten or augment the separation process. At separation facilities where produced water is injected, the produced water is typically filtered prior to injection. Although used in the Gulf, gas flotation is not used widely enough in coastal operations to be considered a typical BPT process. Many coastal operations, however, use subsurface injection, as the number of nondischarging facilities in the Gulf Coastal region reflects (see PEIA).

The Major Pass discharging operations include eight facilities (identified as outfalls) operating under six permits. One facility is shared by two firms that are owned by a third parent company. One of these subsidiaries also operates another facility. One other firm operates three facilities, and the rest operate one facility each. Current total annual produced water discharge from these facilities is 69.8 million barrels (bbls), with future projections of 104.7 million bbls annually; average daily discharge ranges from 572 to 153,895 barrels per day (bpd). The largest facility is currently using an improved gas flotation unit, which reduces the oil and grease to a 42 mg/L daily maximum, and a 29 mg/L monthly average; the rest are using technologies similar to those discussed above.

Cook Inlet Operations

Fifteen platforms are located in Cook Inlet, Alaska. However, two of these platforms are currently shut in (Spark and Spur—both owned by Unocal). Thus, 13 Cook Inlet platforms are operating with a total of 224 productive wells (see EPA's Development Document). Table 3-1 lists the platforms, the number of wells on each platform, and the owner/operator of each platform. As shown, there are 197 oil wells and 27 gas wells in Cook Inlet. Based on the daily production figures shown, estimated total annual production (1995) is 13.7 million bbls of oil and 140,525 million Mcf of marketable gas (see EPA's Development Document). EPA estimates total lifetime production (using the production loss model under baseline assumptions—see

TABLE 3-1

PLATFORMS, OPERATORS, AND WELLS IN COOK INLET

Platform	Operator	No. of Active Oil Wells	No. of Active Gas Wells	Oil Production (bpd)	Gas Production (Mcf)	Discharge Location
King Salmon	Unocal	19	1	3,864	Plat. use	Trading Bay
Monopod	Unocal	22	0	1,981	Plat. use	Trading Bay
Grayling	Unocal	23	1	5,207	Plat. use	Trading Bay
Granite Point	Unocal	11	0	6,086	Plat. use	Granite Point
Dillon	Unocal	10	0	841	0	Platform
Bruce	Unocal	13	0	865	Plat. use	Platform
Anna	Unocal	23	0	3,117	Plat. use	Platform
Baker	Unocal	14	2	1,301	Plat. use	Platform
Dolly Varden	Unocal	24	1	4,983	Plat. use	Trading Bay
Spark	Unocal	0*	0*	0	0	Platform
Steelhead	Unocal	4	9	4,184	165,000	Trading Bay
Spurr*	Unocal	0*	0*	0	0	Granite Point
SWEPI "A"	Shell Western	17	0	3,200	Plat. use	E. Foreland
SWEPI "C"	Shell Western	17	0	1,800	Plat. use	E. Foreland
Tyonek "A"	Phillips	0	13	0	220,000	Platform

*Spark and Spurr are considered completely nonactive in this EIA.

Source: U.S. EPA. 1996. Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category.

Chapter Five) to be 311 million PVBOE, or 501.1 million BOE (undiscounted).[38] Over a period of 7 years, producers plan to drill 41 new wells and expect to perform 20 recompletions (see Chapter Four for a detailed drilling schedule by platform).[39]

A potential area of development in Cook Inlet is the Sunfish Field, which is located in North Upper Cook Inlet. At this time, the Sunfish Field has not been brought into production, and as noted earlier, no new platforms are planned.[40]

Three land-based and five platform-based separation/treatment facilities operate in Cook Inlet. The three land-based facilities (the largest of which is the Trading Bay facility) treat and discharge about 98 percent of all produced water at a rate of about 130,000 bpd (see EPA's Development Document). One platform and one land-based facility currently use gas flotation (in addition to skim tanks, a type of gravity separator). Most other facilities use skim tanks only, or a combination of skim tanks and corrugated separators (see EPA's Development Document).

3.3.2 Oil and Gas Firms Operating in the Coastal Subcategory

The expenditures required to comply with the Coastal Guidelines for the coastal oil and gas industry will be financed by coastal firms and their investors. Coastal oil and gas producers can be divided into two basic categories. The first category consists of the major integrated oil companies, which 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 coastal producers consists of independents engaged primarily in exploration, development, and

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[38]Cook Inlet Production Loss Model Runs (CBI data in rulemaking record).

[39]Marathon/Unocal, 1994. "Zero Discharge Analysis: Cook Inlet, Alaska." Marathon Oil Company and Unocal Corporation. March.

[40]Wiedeman, Allison, U.S. EPA, Personal communication with Jim Short, ARCO, dated May 9, 1994, regarding ARCO's future drilling activity in Cook Inlet—status of ARCO's Sunfish operations in Cook Inlet, Alaska.

production of oil and gas and not typically involved in downstream activities. Some independents are strictly producers of oil and gas, while others maintain some service operations, such as contract drilling and well servicing. The major integrated oil companies are generally larger than the independents. As a group, the majors typically produce more oil and gas, earn significantly more revenue and income, and have considerably more assets and greater financial resources than the independents. Furthermore, majors tend to be relatively homogeneous in terms of size and corporate structure. All majors are considered large firms under the Regulatory Flexibility Act (RFA) guidelines, and generally all are standard corporations (i.e., the corporation pays income taxes).

Independents can vary greatly by size and corporate structure. Larger independents tend to be standard corporations (i.e., they pay corporate taxes); smaller firms might also pay corporate taxes, but they can also be organized as S corporations,[41] limited partnerships, sole proprietorships, etc., whose owners, not the firms, pay taxes.

The firms that EPA estimates will be affected by the Coastal Guidelines include three majors in the Major Pass discharger group (reduced to two in a financial sense, since two of the three are Chevron subsidiaries), three majors in the Cook Inlet group, and three independents (one publicly held) in the Major Pass discharger group. All the Major Pass dischargers and Cook Inlet firms that provided financial data are standard corporations.

The oil and gas industry as a whole has been through a number of changes in the 1990s. Since the early 1990s, which were hard years in the U.S. oil and gas industry,[42] the industry has experienced a major upturn. By 1993, net income of the 300 largest firms rose 75.5 percent from the previous year,[43] although some of this apparent improvement can be attributed to

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[41]S corporations are corporations that have elected to be taxed at the shareholder level rather than the corporate level under Subchapter S of the Internal Revenue Code.

[42]"Financial Operating Results Sag for OGJ 300 Companies," Oil and Gas Journal (OGJ), Vol. 90, No. 39, September 28, 1992, p. 49.

[43]"Total Earnings Rose, Revenues Fell in 1993 for OGJ 300 companies," Oil and Gas Journal (OGJ), September 5, 1994, pp. 49-59.

accounting changes. More recently, in 1995, conditions improved further, and OGJ indicated that demand is expected to grow between 1997 and 1999.[44] Additionally, prices have risen substantially in 1996, bolstering an active and relatively healthy industry. OGJ paraphrases Arthur Anderson: "The U.S. oil and gas industry is in its best shape in more than 15 years and is poised for a period of sustained growth."[45] The affected firms will very likely follow this projected trend. Despite the recent improvements, mergers, acquisitions, consolidations, and liquidations have been common; the *Oil and Gas Journal*'s OGJ 400 was cut to 300 firms in 1991,[46] and further cut to 200 in 1996.[47] These consolidations, however, have tended to eliminate the weaker firms, leaving those surviving firms an increasingly healthy group.

The following sections profile Major Pass dischargers and Cook Inlet operators. Two operations in the Major Pass discharger group are not profiled since they are not publicly owned and in-depth profiles of these firms could create confidentiality problems.

EPA conducted several analyses to determine the financial status of the Major Pass and Cook Inlet firms. The Agency investigated financial ratios using benchmarks from the OGJ 200,[48,49] which provides 1995 financial data. A brief definition of the measures of financial health used to characterize the firms are as follows:

- *Total Assets*. The sum of all liquid (cash-type) and nonliquid (e.g., real estate) assets of the company.

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[44]"Strong Demand Growth Seen for Oil and Gas in 1997-1999," Oil and Gas Journal (OGJ), Vol. 94, No. 17, April 22, 1996, p. 45-59.

[45]"Newsletter," Oil and Gas Journal (OGJ), Vol. 94, No. 36, September 2, 1996, p. 2.

[46]"OGJ 300: Smaller List, Bigger Financial Totals," Oil and Gas Journal (OGJ), Vol. 89, No. 39, September 30, 1991, pp. 49-56.

[47]The number of publicly held firms dropped to 281 in 1995. "Consolidation Shrinks List of U.S. Companies," Oil and Gas Journal (OGJ), Vol. 94, No. 36, September 2, 1996, pp. 45-54.

[48]"Consolidation Shrinks List of U.S. Companies," Oil and Gas Journal (OGJ), Vol. 94, No. 36, September 2, 1996, pp. 45-54.

[49]"OJG 200," Oil and Gas Journal (OGJ), Vol. 94, No. 36, September 2, 1996, pp. 56-74.

- *Equity*. Total assets minus total liabilities, or the firm's net worth.

- *Profitability*.

  — Return on Assets (ROA): Net income over total assets. The median for the OGJ 200 was 3.9 percent in 1995.

  — Return on Equity (ROE): Net income over equity or net worth. The median for the OGJ 200 was 10.7 percent in 1995.

  — Profit Margin: Net income over sales (revenues). The median for the OGJ 200 was 3.6 percent.

Benchmarks are useful in showing how healthy a firm or a subset of an industry is in comparison to the industry as a whole. In general, if the firm or segment is at the median or above, it can be considered relatively healthy. A firm somewhat below the median would be considered weak but in potentially acceptable financial health, while a firm below the lowest quartile (only a quarter of firms in the industry have a measure that low or lower) can be considered in poor financial health. In the case of the OGJ 200, all lowest quartile profitability measures are negative, so any positive returns are better than the lowest quartile among this group. If, however, the financial health of the entire industry is poor relative to all industries, even better-performing firms might be considered in poor financial health.

Table 3-2 presents summary financial data on all publicly held firms in the affected coastal regions. As Table 3-2 shows, the majors tend to have the greatest assets and equity. The only independent shown here, Flores & Rucks, shows as good or better returns (for example, a 50 percent return on equity) and profit margins despite being smaller than the majors. All the firms shown in this table are considered to be operating profitably and to be in adequate to good financial health. Most firms show returns at or above the median for the OGJ 200; none have negative returns, which would tend to indicate poor financial health. Those below the median are generally only slightly below. This table also presents the capital and exploration spending by the firms in 1995. These figures provide some sense of the level of capital that might be available annually to these firms. A portion of this capital could be diverted to capital expenditures on pollution control equipment.

TABLE 3-2

SUMMARY OF KEY FINANCIAL INDICATORS IN PUBLICLY HELD COASTAL FIRMS AFFECTED BY THE EFFLUENT GUIDELINES
($ millions 1995)

	Capital & Expl. Spending	Assets	Return on Assets	Equity	Return on Equity	Net Income	Revenues	Profit Margin (net income to total revenues)
Cook Inlet								
Shell Oil Co.	$2,957	$27,021	5.6%	$13,853	11.0%	$1,520	$24,650	6.2%
Phillips Petroleum	1,456	11,978	3.9%	3,188	14.7%	469	13,521	3.5%
Unocal	1,459	9,891	2.6%	2,930	8.9%	260	8,425	3.1%
Major Pass								
Amoco	4,136	29,845	6.2%	14,848	12.5%	1,862	31,004	6.0%
Chevron[1]	4,800	34,330	2.7%	14,355	6.5%	930	37,082	2.5%
Flores & Rucks	76	216	4.6%	20	50.0%	10	128	7.8%

Source: "OJG 200," Oil and Gas Journal (OGJ), Vol. 94, No. 36, September 2, 1996, pp. 56-74.

[1]Two of the firms in the Major Pass group are subsidiaries of Chevron.

Among the two nonpublic firms, one declined to provide EPA with financial information but indicated that achieving zero discharge would not cause a significant problem for the firm. EPA does not consider the remaining nonpublic firm to be in poor financial health. More detail is not provided to protect confidentiality but is included in the CBI record for this rulemaking.[50]

[50]Major Pass Dischargers Data Submittals (CBI data; in the rulemaking record).

CHAPTER FOUR

ECONOMIC IMPACT ANALYSIS METHODOLOGY OVERVIEW AND AGGREGATE COMPLIANCE COST ANALYSIS

4.1 OVERVIEW OF METHODOLOGIES

In this chapter, EPA presents an overview of potential impacts of regulatory options for the Coastal Guidelines. The overall analysis covers:

- Compliance costs to industry.
- Production losses (in terms of quantities of hydrocarbons not produced compared to a no-regulation [baseline] scenario).
- Lost economic lifetime (i.e., the loss of productive years associated with wells shutting in earlier under the regulation than under a baseline scenario).
- Numbers of production facilities or platforms immediately ceasing production as a result of the regulation (first-year shut-in).
- Losses to operators (in terms of annualized compliance costs and losses in present value of project net worth to the operator [NPV]),[1] state governments, and the federal government.
- Firm-level impacts (firm failure analysis).
- Employment impacts (losses and gains in employment).
- Balance of trade and inflation impacts.
- Impacts on small businesses (an analysis of whether impacts on small businesses are severe, required by the Regulatory Flexibility Act [RFA], as amended).
- Impacts on new sources (barriers to entry).

[1]NPV is the total stream of a project's (e.g., platform's or facility's) cash inflows minus cash outflows (operating costs, taxes, and investments) over a period of years (the facility's or platform's lifetime) discounted back to present value.

These individual analyses are interrelated, with the output of one analysis often used as input for another analysis. The general flow of the analyses and their relationship to one another are shown in Figure 4-1. As the figure shows, the first step in the analysis is to identify the appropriate inputs. Because compliance costs (capital as well as operating and maintenance [O&M] costs) are major inputs to all of these analyses, how these costs are annualized is a key methodological decision. Section 4.2 discusses how and why costs are annualized, Section 4.3 describes all the regulatory options under consideration and the options selected for the Coastal Guidelines, and Section 4.4 presents total aggregate compliance costs associated with each of the BAT regulatory options and the Coastal Guidelines as a whole (the costs for the selected regulatory options).

The first major analysis following cost annualization is the production loss analysis.[2] In general, EPA calculates compliance costs based on the volume of wastes generated by each discharging treatment/separation facility.[3] EPA then inputs the total compliance costs associated with each treatment facility into an economic model of surveyed platforms (Cook Inlet, Alaska), and treatment facilities (Major Pass operations) to look at annual cash flow and production decisions (produce/shut in) based primarily on production operating cash flow (see Chapter Five for more details). Compliance costs and production losses lead to losses in economic lifetime (when the decision to shut in is made earlier than if the regulation were not in effect), which in turn leads to production losses. Sometimes the results indicate that the operator might shut in a

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[2]The cost annualization method used in this chapter (Chapter Four) is a simple method using only the discount rate and number of years assumed to be typical for the life of a well, a platform, or for drilling activity. The production loss model for Cook Inlet and Major Pass dischargers uses a more sophisticated method to calculate annual costs that takes into account accelerated depreciation and the modeled life of each platform (see Section 5.1). The simple annualization used in Chapter Four produces pre-tax estimates of compliance costs and thus overstates costs and impacts to producers because the state and federal governments will partially subsidize these expenditures through deductions for accelerated capital equipment depreciation and increased operating costs, which serve to reduce taxable income. The more sophisticated Cook Inlet/Major Pass model can calculate the actual cost faced by producers in each year (a post-tax cost). Additionally, if any baseline or first-year shut-ins occur, some portion of the compliance costs presented in this chapter will not be incurred.

[3]Compliance costs, i.e., capital and O&M costs to achieve different levels of control, were derived separately from this economic analysis effort and are presented in a separate document (see EPA's Development Document, for more details on the derivation of compliance costs).

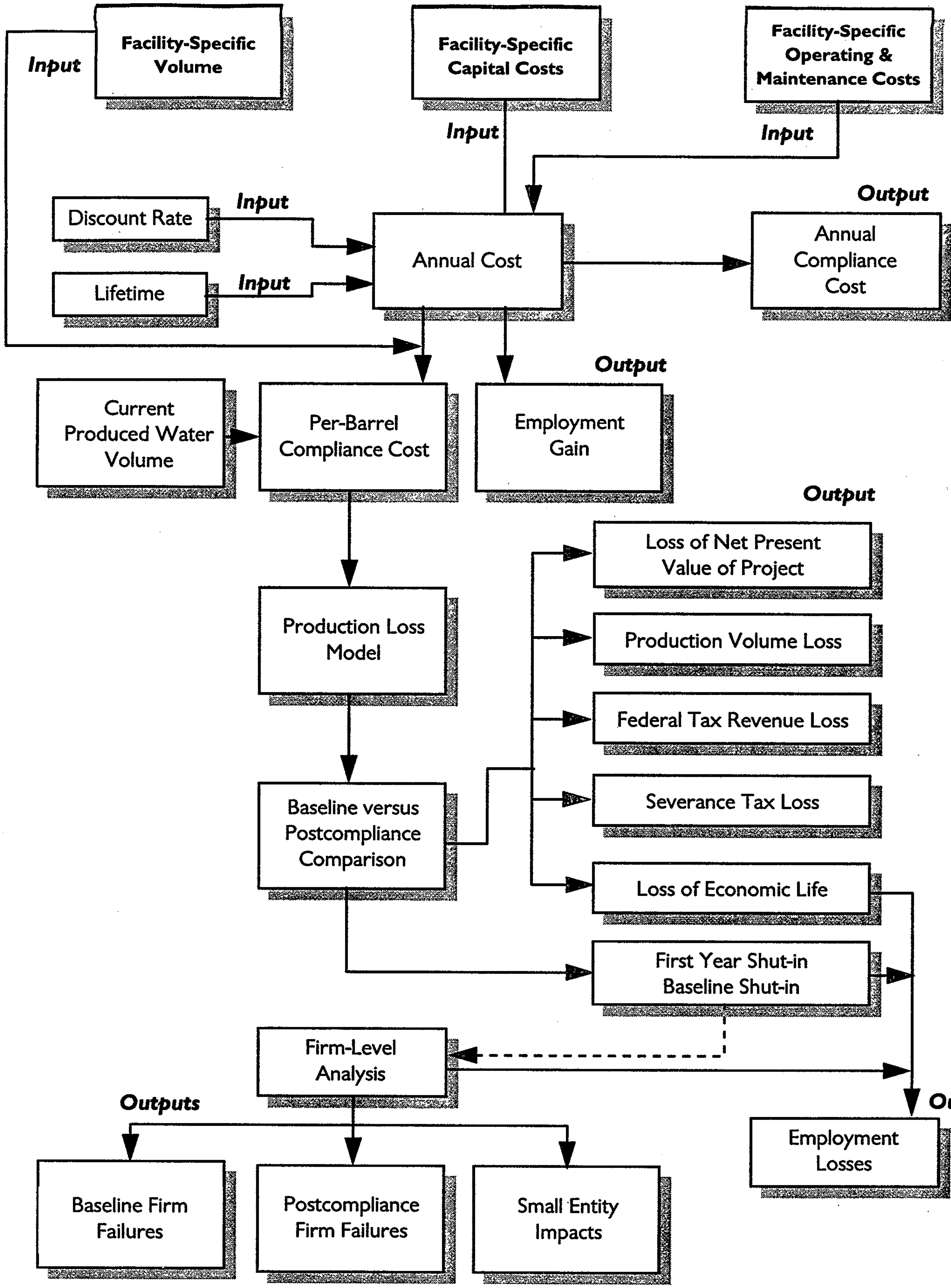

Figure 4-1. Overview of methodology for the economic impact analysis.

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platform or facility as soon as the regulation becomes effective (referred to here as a first-year shut-in); the Agency tallies this result. Compliance costs and production losses also lead to declines in the present value of the project's net worth (i.e., NPV), which can be estimated when EPA compares the model outputs from a baseline scenario to those from a postcompliance scenario. The detailed methodology for the production loss modeling is discussed in Chapter Five and Appendix A. Results are presented in Chapter Five. Production losses, first-year shut-ins, and declines in the present value of project net worth (NPV) lead to secondary impacts on federal and state revenues (see Chapter Five), operator revenues (see Chapter Five), employment (see Chapter Seven), and possibly the balance of trade and inflation (see Chapter Eight).

For the firm-level analysis, EPA again uses annual compliance costs compiled on an operator-by-operator basis. The Agency compares these costs to working capital and equity among the affected firms. Where a reduction in working capital and equity both exceed 5 percent, a more in-depth analysis, looking at cash flows and/or facility-specific data (where possible), is undertaken to identify whether firm failure is a possibility (see Chapter Six). Because a firm can use equity, working capital, or a combination of the two (among other sources of financing), EPA judges that a firm will be able to obtain the capital and maintain and operate the pollution control equipment if at least one measure changes by less than 5 percent.

4.2 COST ANNUALIZATION PURPOSE AND METHOD

EPA uses cost annualization to estimate the annual compliance cost to the operators of new pollution control equipment. The cost of additional pollution control equipment has two components: the initial capital investment to purchase and install the equipment, and the annual cost of operating and maintaining such equipment. Capital costs are a one-time expense incurred only at the beginning of the equipment's life, and O&M costs are incurred every year of the equipment's operation.

To determine the economic feasibility of upgrading a treatment facility or transporting and disposing wastes at a commercial facility, the costs for such efforts must be compared against the operation's annual revenues and its operator's capital structure. The initial capital outlay should not be compared against the operation's or operator's income in the first year because this capital cost is incurred only once. Additionally, annualizing costs over several years reflects the common practice of financing capital expenditures, as well as the IRS requirement that capital expenditures on pollution control be amortized and depreciated, not expensed.[4,5] This initial investment, therefore, should be spread out over either the well's or platform's life or the equipment's life. Annualizing costs is a technique that allocates the capital investment over the lifetime of the equipment, incorporates a cost-of-capital factor to address the costs associated with raising or borrowing money for the investment, and includes annual O&M costs. The resulting annualized cost represents the average annual payment that a given company will need to make to upgrade its facility. The annualized cost is analogous to a mortgage payment, which spreads the one-time purchase price of a home (the capital investment) into a series of constant monthly payments.

In this section, the Agency annualizes costs using three inputs: the initial capital costs, the discount rate, and the time period over which payments are made. EPA has set the discount rate (real, adjusted for inflation) at 7 percent for simplicity. The average cost of capital over all coastal respondents in the Section 308 Survey was estimated as 8 percent, but the typical (mean) rate for Major Pass dischargers, weighted by production volumes, is 7 percent. Additionally, the Office of Management and Budget (OMB) recommends a 7 percent real discount rate[6] for discounting social costs and benefits. The difference in results using 7 percent and 8 percent is negligible.

The time period over which costs are annualized is 10 years for produced water and TWC wastes and 7 years for drilling waste, since drilling will only occur during approximately a 7-year

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[4]Houghton, James L. 1987. Arthur Young's Oil and Gas Federal Income Taxation. Commerce Clearing House, Inc., Tulsa, OK.

[5]Research Institute of America. 1995. The Complete Internal Revenue Code. Research Institute of America, New York, NY.

[6]U.S. Office of Management and Budget (OMB). Economic Analysis of Federal Regulations under Executive Order 12866. January 11, 1996.

period in Cook Inlet.[7] Because the drilling waste disposal equipment might not be used past this 7-year life, the Agency has used a 7-year period to amortize the capital costs of drilling-waste disposal options.[8] Ordinarily, pollution control equipment is amortized over 15 years, but in this case, because remaining project lives tend to be less than 15 years, EPA has selected a 10-year amortization period over which to annualize pollution control costs. Because well life does not necessarily relate to treatment facility life (wells can be shut in and new wells can be drilled to replace them), EPA considers the 10-year period over which to amortize costs a conservative estimate of project lifetime. The shorter the time frame used in the analysis, the higher (and thus more conservative) the estimate of annual compliance costs will be.

The Agency undertook the cost annualization for drilling wastes in this section in a slightly different manner than for the other waste streams. Unlike other wastes, which EPA could assume are disposed of every year, drilling wastes are disposed of each time a well is drilled. Based on a drilling schedule provided by Cook Inlet operators, the above discount rate and time period assumptions, and the capital and O&M costs for all planned drilling projects (see EPA's Development Document), the Agency calculated a present value for all costs over a 7-year period and then annualized these costs to create a consistent stream of payments over the time frame. This approach is discussed in more detail in Section 4.3.2.

4.3 REGULATORY OPTIONS

The regulatory options that EPA developed are the basis for the engineering cost estimates that feed into the cost annualization. This section summarizes these options. EPA's

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[7]Industry supplied EPA with its plans to drill in Cook Inlet until approximately 2002 or a few years beyond (Marathon/Unocal. 1994. "Zero Discharge Analysis: Cook Inlet, Alaska." Marathon Oil Company and Unocal Corporation. March.). EPA selected 7 years as the time between the expected promulgation date of this rule and end of drilling. Beyond this time, the operators did not provide drilling plans.

[8]This is a conservative assumption that overstates compliance costs as reported in this section. In Chapter Five, the Cook Inlet/Major Pass model is able to determine the actual life of the platforms in question to compute a more precise, post-tax compliance cost estimated to affect producers.

Proposal Development Document[9] contains a detailed discussion of the derivation of the initial engineering cost estimates under each option.

EPA is required under Sections 301, 304, 306, and 307 of the Clean Water Act (the Act) to establish effluent limitations guidelines and standards of performance for industrial dischargers. EPA has already promulgated best practicable technology (BPT) regulations. Pursuant to this authority, EPA is promulgating the following effluent limitations guidelines and standards:

- BPT—For produced sand only. BPT had been set previously for all other wastestreams.
- BCT—Effluent reductions employing the best conventional pollutant control technology as required under Section 304(b)(4) (applicable to conventional pollutants).
- BAT—Effluent reductions employing the best available control technology economically achievable as required under Section 304(b)(2) (applicable to nonconventional and toxic pollutants).
- NSPS—New source performance standards covering direct discharging new sources as required under Section 306(b) of the Act (applicable to all pollutants).
- PSES—Pretreatment standards for existing sources (indirect discharges to publicly owned treatment works [POTWs]; applicable to all pollutants).
- PSNS—Pretreatment standards for new sources (indirect discharges; applicable to all pollutants).

For the purposes of analysis, the range of BCT, PSES, NSPS, and PSNS options evaluated by EPA are identical to BAT options, although the pollutants controlled through BCT requirements are total suspended solids (TSS) and oil and grease only (conventional pollutants). In all cases, selected PSES and PSNS options equal zero discharge. EPA knows of no existing indirect dischargers and anticipates no new ones. Therefore, EPA estimates that PSES and

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[9]U.S. EPA. 1995. Development Document for Proposed Effluent Limitations, Guidelines, and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. Washington, D.C. January 31.

TABLE 4-1

BAT REGULATORY OPTIONS CONSIDERED IN THE ECONOMIC IMPACT ANALYSIS

Type of Waste Stream	Name	Description
Produced water/TWC fluids	Option #1	Zero discharge all, except for Major Pass and Cook Inlet operations; for exceptions, limitations equal to "offshore limits" apply
	Option #2	Zero discharge all, except for Cook Inlet operations; for exceptions, limitations equal to "offshore limits" apply
	Option #3	Zero discharge all
Drilling wastes	Option #1	Zero discharge all, except for discharge limitations equivalent to current practice in Cook Inlet
	Option #2	Zero discharge all

PSNS options for indirect dischargers will have no costs or impacts. This section discusses the BAT, NSPS, and BCT options for the following waste streams:

- Produced water and well treatment, workover, and completion (TWC) wastes
- Drilling fluids and drill cuttings

The following waste streams also are regulated:

- Deck drainage
- Produced sand
- Sanitary waste
- Domestic waste

This FEIA does not assess impacts associated with these four waste streams because EPA is selecting regulatory options for them that are equivalent to current practice and therefore impose no costs on the industry.

All of the BAT, NSPS, and BCT options for produced water/TWC and drilling wastes are described below in detail. (BAT options considered for waste types are summarized in Table 4-1.) The selected options for produced sand, deck drainage, sanitary waste, and domestic wastes also are briefly discussed. Note that BAT options for TWC wastes and produced water, discussed separately in the proposal, are now combined.

4.3.1 Produced Water and TWC Wastes

Certain operations in the Gulf of Mexico and Cook Inlet currently discharge produced water and are considered within the scope of the Coastal Guidelines. Additionally, some other Gulf of Mexico operations that currently discharge produced water (but are expected to cease discharging shortly as they are covered under the EPA Region 6 General Permit) might continue to discharge TWC wastes if not for the Coastal Guidelines (the Region 6 permit for produced water does not cover TWC wastes). EPA proposed five BAT options for produced water (and two for TWC wastes), but EPA is considering only three BAT options for produced water/TWC wastes for final promulgation:

- Option #1 is zero discharge, except for Cook Inlet and offshore produced water discharged into a major deltaic pass of the Mississippi River. For these exceptions, limits on total oil and grease are 29 mg/L for monthly average and 42 mg/L for daily maximum (known henceforth as "offshore limits").

- Option #2 requires zero discharge except for Cook Inlet. For the exception, requirements equivalent to "offshore limits" must be met.

- Option #3 requires zero discharge for all operations.

The selected BAT regulatory option is Option #2, which prohibits discharge in the Gulf of Mexico but allows operations in Cook Inlet to meet limits equivalent to offshore limits. The selected NSPS option is also Option #2, thus NSPS equals BAT (see Chapter Nine for a discussion of NSPS). All options fail the BCT cost test (see EPA's Development Document), so BCT is set equal to BPT, as required by Clean Water Act regulations.

4.3.2 Drilling Fluids and Drill Cuttings

All coastal areas, with the exception of Cook Inlet, are currently achieving zero discharge of drilling fluids and drill cuttings. EPA Region 6 has promulgated a General Permit prohibiting the discharge of drilling fluids and cuttings[10]; discharge of these wastes also is prohibited in states outside Region 6 with coastal oil and gas operations (see Chapter Three), except for Alaska. Also included in this waste stream is drill water effluent, but little to no drill water effluent is currently discharged (see EPA's Proposal Development Document). EPA proposed three BAT options, but is considering only two here (a toxicity-based option was dropped due to lack of data):

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[10] 58 *Federal Register* 49126, September 21, 1993. Final NPDES General Permits for the Coastal Waters of Louisiana (LAG330000) and Texas (TXG330000).

- Option #1 requires zero discharge, except that Cook Inlet operations are required to meet limitations equivalent to offshore limitations (30,000 ppm toxicity limitation, no discharge of free oil, no discharge of diesel oil, and a mercury/cadmium limitation in barite). This option reflects current practice and is a no-cost alternative.

- Option #2 requires zero discharge, regardless of location.

EPA has selected Option #1. EPA's selected NSPS option is also Option #1. EPA has selected this option for both BAT and NSPS for the reasons stated in the preamble to the final rule. Given that Option #2 does not pass the BCT cost test for the transport and landfilling scenario, EPA has set BCT equal to BPT. Thus no costs are associated with this selected option for either BAT or NSPS. EPA has set PSES and PSNS to zero discharge, and thus these options also impose no costs.

4.3.3 Other Miscellaneous Wastes

EPA has selected zero discharge for produced sand under BPT, BAT, NSPS, PSES, and PSNS, and has set BCT equal to BPT. This is a no-cost option (zero discharge is current practice).

For deck drainage, EPA has set BAT, BCT, and NSPS requirements equal to BPT: no free oil. EPA expects no costs or impacts because the proposed requirements are current practice. The Agency also has set PSES and PSNS to zero discharge. As this is current practice, this is also a zero-cost option.

EPA's NSPS and BCT options for sanitary waste only apply to facilities continuously manned by 10 or more persons. Sanitary effluent must contain a minimum residual chlorine content of 1 mg/L, with the chlorine level maintained as close to this concentration as possible. Facilities continuously manned by nine or fewer persons must not discharge floating solids. Alternative water quality-based limitations may be used to address state standards for total residual chlorine. These options are equivalent to current practice and thus are no-cost options. EPA has considered no BAT limitations (because the only parameters considered for regulation are conventional) and has set no PSES or PSNS limitations (these are standard wastes for POTWs).

The options selected for domestic wastes are as follows: BCT is no discharge of floating solids or garbage, BAT is no discharge of foam, and NSPS is no discharge of floating solids, foam, or garbage. PSES and PSNS are not regulated (domestic wastes are standard wastes for POTWs). These options are equivalent to current practice and thus are no-cost options.

4.4 AGGREGATE COMPLIANCE COSTS

This section presents the aggregate compliance costs for BAT options for the waste streams considered in this FEIA, and also presents estimates of costs of NSPS under the selected option for produced water/TWC and drilling wastes (NSPS costs for other waste streams are zero). These estimates of compliance costs are considered worst-case because in some instances certain costs will not be incurred. For example, if a facility is projected to shut in in the baseline analysis, costs to meet zero discharge requirements will not be incurred. Nonetheless, the compliance cost analysis discussed below includes such costs.

4.4.1 BAT Options

4.4.1.1 Produced Water/TWC Wastes

EPA has derived the aggregate compliance costs for produced water from estimates of capital and operating costs for the following types of locations and pollution control approaches (see EPA's Development Document):

- Gulf of Mexico

  — Improved gas flotation: Capital and operating expenditures to install improved gas flotation equipment (i.e., equipment capable of meeting the more stringent offshore limitations on grease and oil) at discharging separation/treatment facilities were estimated. The discharging separation/treatment facilities of concern are those Gulf of Mexico operations that will need to dispose of TWC wastes (EPA's Proposal Development Document), as well as Major Pass dischargers.

  — Zero discharge: Capital and operating expenditures to install injection wells or to transport produced water to commercial disposal facilities were estimated for the same group of treatment facilities identified above. In general, injection wells were assumed to be installed at the larger treatment facilities, whereas produced water from the smaller facilities was assumed to be transported to a commercial disposal facility.

- Cook Inlet

  — Improved gas flotation: Costs to install and operate improved gas flotation equipment were derived for each platform (where platform treatment and discharge currently takes place) or centralized onshore treatment facility (where produced water is piped to shore for treatment).

  — Zero discharge: Costs to install and operate injection wells, as well as relevant piping, were derived for each platform or onshore treatment facility.

After EPA annualized the capital costs and added them to operating costs for each platform or facility, it combined costs for each of these options within regions. Aggregate annualized compliance costs for Options #1 through #3 are shown in Table 4-2. The compliance costs range from $3.7 million to $47.9 million. The selected option, Option #2, is associated with costs totaling $15.6 million. The columns for each affected group do not add to the total because TWC waste disposal costs of $0.7 million per year have not been broken down by group but instead have been added to the total to reflect the fact that they affect not only the Major Pass operations, but also certain other operations in the Gulf. Total Cook Inlet costs already incorporate costs to dispose of TWC wastes. Note that EPA has calculated all compliance costs on a pre-tax basis. This approach overestimates the annual costs to industry because the state and federal governments will partially subsidize these expenditures through deductions for accelerated capital equipment depreciation and increased operating costs, which serve to reduce taxable income. Although EPA has not calculated post-tax compliance costs to

TABLE 4-2

AGGREGATE ANNUAL COSTS FOR BAT OPTIONS BY REGULATORY OPTION AND AFFECTED GROUP ($ millions 1995)

Type of Waste Stream	Option Number	Major Pass	Cook Inlet	Aggregate Annual Cost (Pre-tax)
Produced water/TWC fluids	Option #1	$0.5	$2.5	$3.7
	Option #2	$12.5	$2.5	$15.6
	Option #3	$12.5	$34.8	$47.9
Drilling waste	Option #1	$0	$0	$0
	Option #2	$0	$9.2	$9.2

Note: Aggregate totals include costs of $0.7 million for TWC, while costs for individual affected groups do not.

Source: ERG estimates based on engineering costs from EPA's Development Document.

industry, in Chapter Five the Agency uses post-tax costs to estimate changes in project net worth and production losses and also estimates the reduction in tax revenues to the state and federal governments from both compliance cost effects and production losses.

4.4.1.2 Drilling Waste

In all coastal subcategory locations but Cook Inlet, zero discharge of drilling waste is current practice; consequently, requirements for drilling waste under the Coastal Guidelines are no-cost requirements. In Cook Inlet, Option #1 is current practice, but Option #2 requires zero discharge of drilling waste. For Cook Inlet dischargers, EPA has derived aggregate compliance costs for zero discharge of drilling wastes from estimates of capital and operating costs (presented in EPA's Development Document) under two scenarios: 1) drilling waste is disposed of by grinding and injecting the waste into Class II injection wells, and 2) drilling waste is disposed of by transporting waste to onshore disposal facilities using closed-loop systems to reduce wastes. EPA uses the more expensive scenario (onshore disposal) here as the relevant cost of compliance because it is not clear that injection is technologically feasible.

In annualizing costs, EPA first calculated costs for landfill disposal per barrel of waste and converted these to costs per new or recompleted well drilled, based on the expected volume of wastes. Then, using a drilling schedule developed from discussions with operators (Table 4-3), EPA developed a cost schedule based on the drilling schedule (Table 4-4). Costs assumed to be incurred in the first year include all capital costs for any operations incurring a capital cost, plus the costs to dispose of wastes from the wells planned to be drilled in the first year. In the second and subsequent years, EPA included only those costs for disposing of the wastes from wells planned to be drilled. To derive an annualized cost figure, the Agency calculated the present value of these expenditures and annualized this value over 7 years, producing a constant stream of expenditures over the 7-year period (Table 4-4).

Table 4-2 presents the aggregate compliance costs for drilling waste Options #1 and #2; compliance costs range from $0 to $9.2 million.

TABLE 4-3

ASSUMED DRILLING SCHEDULE USED FOR ANNUALIZING DRILLING COSTS

Platform	1997	1998	1999	2000	2001	2002	2003
Grayling		3R					
King Salmon		2N, 3R					
Dolly Varden		1N, 2R					
Steelhead	3N	1R					3N
Monopod			4N, 2R				
Baker	3N		3N		2R		
Dillon			2R				
Bruce							
Granite Pt.	4N, 2R						
Anna				5N, 2R			
Spark							
Spurr							
SWEPI A and C	3N				1R		
Tyonek	10N						

N = New well
R = Recompletion

Sources: McIntyre, Jamie, Avanti, Personal communication with Anne Jones, ERG, dated May 17, 1996, regarding numbers of new wells and recompletions to be drilled by platform.

Marathon/Unocal. 1994 "Zero Discharge Analysis: Cook Inlet Alaska." Marathon Oil Company and Unocal Corporation. March.

TABLE 4-4

COST ANNUALIZATION OF DRILLING COSTS FOR ZERO-DISCHARGE OPTION

	1997	1998	1999	2000	2001	2002	2003	Total	NPV	Annual Cost
UNOCAL/MARATHON	$14,935,517	$5,309,670	$9,236,105	$6,438,237	$370,956	$0	$3,640,368	$39,930,853	$33,578,736	$6,230,643
SHELL	$4,143,000	$0	$0	$0	$197,363	$0	$0	$4,340,363	$4,012,680	$744,566
PHILLIPS	$13,066,153	$0	$0	$0	$0	$0	$0	$13,066,153	$12,211,358	$2,265,857
TOTAL	$32,144,670	$5,309,670	$9,236,105	$6,438,237	$568,319	$0	$3,640,368	$57,337,369	$49,802,774	$9,241,065

Source: ERG estimates based on: U.S. EPA. 1996. Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. Washington, D.C. September.

4.4.1.3 Total Aggregate Compliance Costs for the Selected BAT Regulatory Options

Table 4-5 presents the total aggregate compliance costs for the selected regulatory options (Option #2 for produced water/TWC wastes and Option #1 for drilling waste). These regulatory requirements will amount to $15.6 million annually.

4.4.2 NSPS Options

Produced Water/TWC

For produced water dischargers in the Major Passes, as discussed in EPA's Development Document, EPA does not expect any new sources to discharge to the Major Passes. Further, in the absence of the Coastal Guidelines, any new source in an area covered by the existing General Permit would be subject to zero discharge. For these reasons, there are no costs for NSPS for produced water in the Gulf of Mexico coastal area (see EPA's Development Document).

With respect to produced water/TWC requirements in Cook Inlet, EPA estimates that even if oil prices were to increase substantially, the economics in Cook Inlet preclude the development of a new platform, given the level of production per platform currently and historically seen in the Inlet. EPA constructed a financial model using data from the most recently constructed platform in Cook Inlet and concluded that, given no major changes in oil prices or other unusual conditions, a profitable new platform could not be constructed in the Inlet.[11] Discussions with industry have substantiated EPA's findings (see Chapter Three). The Agency did conduct an analysis to determine if NSPS costs could pose a barrier to entry for new projects in Cook Inlet. The results of this analysis, as well as EPA's baseline NSPS analysis, are presented in Chapter Nine.

Discharge of TWC wastes in the Gulf of Mexico area is not covered by either of the Region 6 General Permits (drilling waste or produced water). Thus, EPA has estimated that 45

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[11]NSPS Production Loss Model Runs (CBI data; in rulemaking record).

TABLE 4-5

AGGREGATE ANNUAL COSTS FOR SELECTED BAT REGULATORY OPTIONS
($ million 1995)

Type of Waste Stream	Selected Option Number	Aggregate Annual Cost Range (Pre-tax)
Produced water/TWC fluids	Option #2	$15.6
Drilling waste	Option #1	$0
Total		$15.6

Source: ERG estimates based on engineering costs from EPA's Development Document.

new wells meeting the definition of a new source will be drilled each year in the Gulf coastal region and will require disposal of TWC fluids (see EPA's Development Document). The costs per year for each group of 45 wells will total $85,909 under Option #1 and $86,363 under Options #2 and #3. In year 1, O&M costs for 45 wells are incurred. In year 2, O&M costs for 90 wells are incurred. In year 3, O&M costs for 135 wells are incurred, and so on out to 15 years. EPA compiled the present value of these capital and O&M outlays over 15 years[12] (at a 7-percent real discount rate). Note that EPA assumed that the initial outlay occurs at the end of 1996 and recurs at the end of every period thereafter (as opposed to occurring at the beginning of the period, which provides a slightly different result). EPA then annualized the present value of these outlays.

The total present value of zero discharge of TWC wastes under NSPS is approximately $5.3 million, with an annual cost around $0.6 million. Table 4-6 presents the cost for the selected NSPS option (Option #1—zero discharge all, except discharge limitations for Cook Inlet).

Drilling Wastes

NSPS for drilling waste is set at zero discharge all, except for Cook Inlet, for which toxicity limits equivalent to current practice is required. Thus NSPS for drilling waste is a no-cost requirement.

4.4.3 Total Estimated Cost of the Coastal Guidelines

The estimated cost of the Coastal Guidelines is $15.6 million per year for BAT requirements and $0.6 million per year for NSPS requirements, for a total of $16.2 million.

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[12]EPA assumed a 15-year lifetime rather than a 10 year-lifetime in the NSPS analysis because new wells or projects should have a longer productive life than existing wells or projects.

TABLE 4-6

TOTAL ANNUAL COSTS FOR ALL SELECTED BAT AND NSPS REGULATORY OPTIONS
($ million 1995)

Type of Waste Stream	Selected Option Number	Aggregate Annual Cost Range (Pre-tax)
Produced water/TWC fluids	Option #2	$15.6
Drilling waste	Option #1	$0
NSPS, produced water/TWC fluids	Option #1	$0.6
Total		$16.2

Source: ERG estimates based on engineering costs from EPA's Development Document.

Thus, this rulemaking does not qualify as a major rule under OMB guidelines (Executive Order 12866) and a Regulatory Impact Analysis (RIA) is not required.

CHAPTER FIVE

PRODUCTION LOSS IMPACTS AND OTHER IMPACTS TO PLATFORMS AND FACILITIES

This chapter describes the production loss model EPA developed to simulate the economic performance of coastal production and drilling projects, as well as the results of inputting the compliance costs into this model. Section 5.1 presents a description of the economic simulation methodology for Cook Inlet and Major Pass operations, and Section 5.2 presents the results of production loss modeling for these groups. Firm-level impacts are discussed later in Chapter Six.

As part of its modeling effort, EPA defines a "baseline" scenario in which modeled treatment/separation facilities and platforms are assumed to be operating without incremental compliance costs. To estimate the incremental impacts of the rulemaking, EPA then compares this baseline scenario to a "postcompliance" scenario that incorporates the costs of complying with new pollution control requirements.

More specific information on the methodology used in this FEIA can be found in the appendices. Appendix A presents detailed derivations of selected assumptions used in the models. Appendix B provides greater detail on the Cook Inlet/Major Pass production loss model and presents the calculations summarized in this chapter.

5.1 DESCRIPTION OF THE ECONOMIC MODEL FOR COOK INLET, ALASKA, OPERATIONS AND MAJOR PASS DISCHARGERS

This section reviews the economic model and its components for Cook Inlet, Alaska, operations and Major Pass dischargers.

Fifteen platforms are located in Cook Inlet, all in the coastal subcategory of the oil and gas extraction point source subcategory. Thirteen of these platforms are currently productive and are included in the Cook Inlet model analysis. Two platforms operated by Shell Western (SWEPI A and SWEPI C) send production to the East Forelands facility and are combined in this analysis to more accurately reflect the circumstances faced by Shell Western in making operating decisions.[1] Phillips operates a single platform (Tyonek A), and Unocal operates four platforms (Anna, Baker, Bruce, and Dillon) and two facilities (Granite Point, which services the Granite Point platform, and Trading Bay, with platforms Dolly Varden, Grayling, King Salmon, Monopod, and Steelhead). Unocal has suspended production at two other platforms (Spurr and Spark); these platforms are not included in the analysis since no associated drilling is planned. ARCO's Sunfish project is uncertain, but it is unlikely that a Sunfish platform will be constructed.[2]

Analysis of coastal oil and gas production for the Major Pass dischargers is conducted at the level of produced water treatment facilities (defined by outfall), rather than at the platform level. There are eight produced water treatment/separation facilities included in the model analysis. All eight discharge offshore produced water into the major passes of the Mississippi River (see EPA's Development Document).

5.1.1 Economic Model Overview

The production loss model simulates the performance and measures the profitability of a petroleum production project. For the Cook Inlet region of the coastal subcategory, EPA defines a project as a single platform or, in the case of SWEPI, the platform pair. For Major Pass dischargers, EPA defines a project as a single facility (i.e., outfall). All projects used in the Cook Inlet/Major Pass model are modeled starting in productive midlife (i.e., not including

[1]At proposal, these were treated as separate facilities.

[2]Wiedeman, Allison, U.S. EPA, Personal communication with Jim Short, ARCO, dated May 9, 1994, regarding ARCO's future drilling activity in Cook Inlet—status of ARCO's Sunfish operations in Cook Inlet, Alaska.

exploration and development costs, which are sunk costs).[3] For each project, modeling inputs include production and operations cost data, typical production rates, oil and gas selling prices, on-going drilling schedules and costs, and other pertinent data. Drilling plans associated with existing structures/facilities and related production increases are also considered. For each project, EPA calculates the annual post-tax cash flow for each year of operation, as well as cumulative performance measures such as the present value of the project net worth (i.e., the net present value [NPV] of the project[4]) and total lifetime petroleum production. The same cash flow results enter into firm-level calculations discussed in Chapter Six.

Figure 5-1 summarizes the schematic design of the EPA model. Three sets of exogenous values are entered into the model: general model parameters (Tables 5-1 and 5-2), project-specific variables, and pollution control costs (discussed in Chapter Four).

Calculation procedures and algorithms in the model duplicate 1) the oil industry's standard accounting procedures, 2) federal taxation rules enacted by the Tax Reform Act of 1986, and 3) standard financial rate-of-return calculation methods. The model's outputs are a series of yearly project cash flows and cumulative performance measures.

EPA incorporates regulatory costs into the economic model by adding regulation-induced capital costs and operating expenses to the set of cost data. The Agency calculates all yearly and cumulative outputs for both the baseline case and the regulated case for each project. The incremental impacts of regulation are the differences in results between these two scenarios.

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[3]OMB directs government agencies to disregard sunk costs in regulatory analysis as part of establishing a baseline (U.S. Office of Management and Budget [OMB]. Economic Analysis of Federal Regulations under Executive Order 12866. January 11, 1996.) As will be discussed in Section 5.1.5.4, cost depletion, which is calculated on the basis of the leasehold cost, would be inappropriate to model because the leasehold cost is a sunk cost.

[4]NPV is the present value of a stream of cash inflows (oil and gas revenues) minus cash outflows (including operating costs, investments, and taxes) from a baseline year to the end of a project's economic life, discounted annually by the real discount rate. The project end is defined as the point when operating costs, including pollution control costs, exceed revenues. The difference between baseline NPV and post-compliance NPV represents the impact of pollution control requirements on an oil and gas project's net worth as seen by the producer.

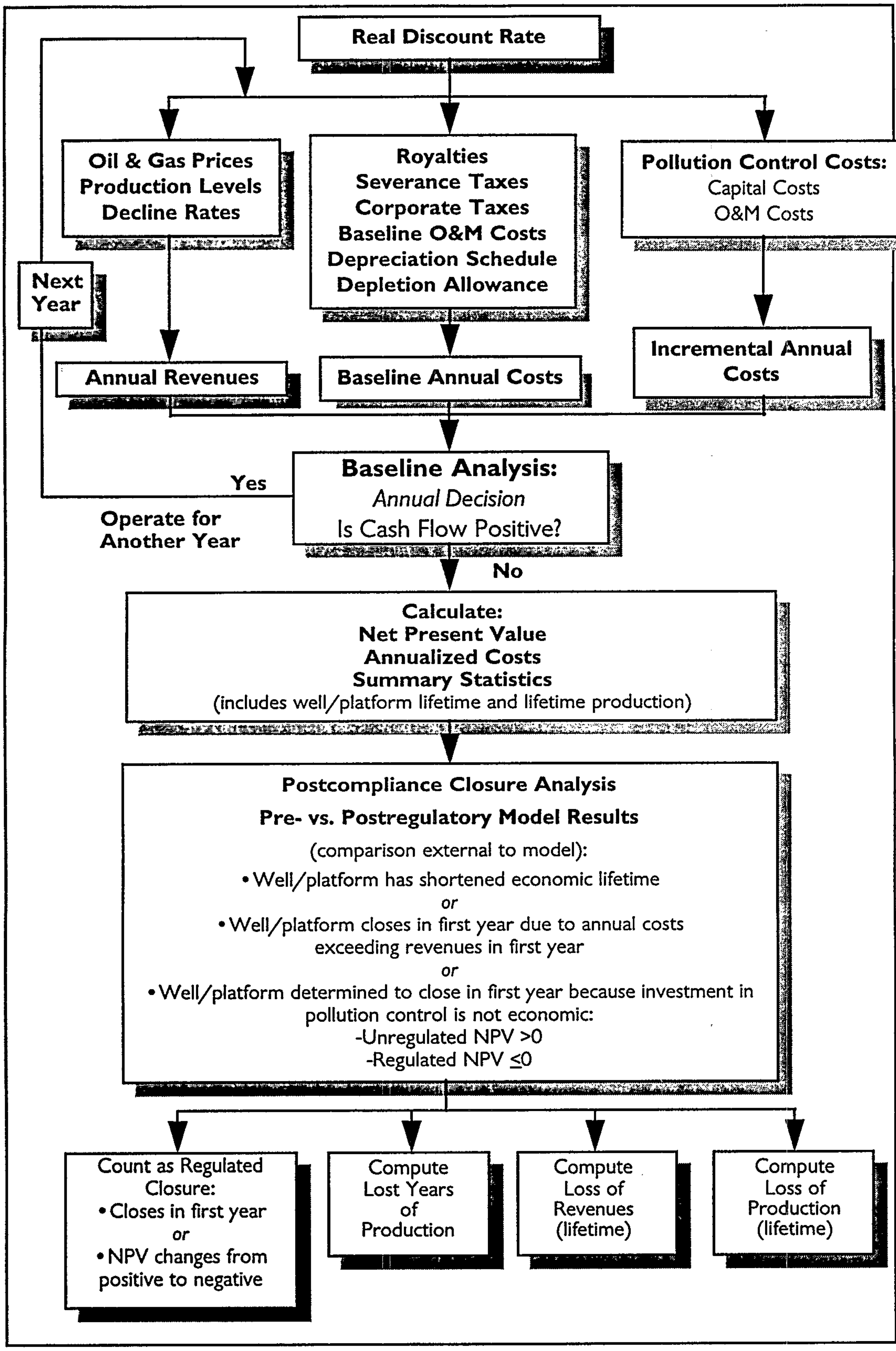

Figure 5-1. Overview of closure analysis methodology

close.ppt

5.1.2 Model Parameters and Variables

A distinct set of parameter values and project-specific variables is required for each of the operating units (platforms or facilities) modeled; this set constitutes a complete economic description of an individual project. EPA has incorporated the following categories of common parameters and project-specific variables into the model:

- *Production rates per operating unit.* Initial production rates of oil and gas, and production decline rates.
- *Baseline operating and maintenance costs per operating unit* (estimated by multiplying the initial year per-BOE cost by the initial year's production in BOE[5]). In the absence of production increases due to drilling activity, total operating costs are held constant over the life of each individual project because it is assumed that the total volume of fluid pumped remains constant even as oil and gas production levels decline. Holding the cost constant has the effect that the per-BOE cost rises over time as production declines. If drilling results in increased production, baseline O&M costs are increased on a per BOE basis or, where sufficient information is available, on a marginal cost per BOE basis.
- *Incremental pollution control capital costs.*[6]
- *Incremental pollution control operating and maintenance costs.* The assumption of constant pollution control O&M costs is made for Cook Inlet platforms and Major Pass facilities, although it does not hold true for individual wells (Chapter Ten uses a different approach since it is based on analysis of individual wells). In Cook Inlet, produced water volumes have remained relatively steady over the last five or six years, and thus are assumed to continue to remain steady. Unocal, in fact, appears to have used a constant O&M compliance cost assumption in its own zero discharge analysis (Marathon/Unocal presentation).[7] Relevant data provided by the Major Pass operators, moreover, also does not appear to support a rising O&M cost assumption.

[5]Barrels of oil equivalent (BOE) represents the total oil and gas produced, with gas converted to an equivalent measurement based on the amount of energy in a cubic foot of gas and the number of cubic feet of gas needed to match the energy in a barrel of oil.

[6]This is an endogenous variable in EPA's analysis (i.e., the costs depend on the pollution control option analyzed).

[7]Marathon/Unocal. 1994. "Zero Discharge Analysis: Cook Inlet, Alaska." Marathon Oil Company and Unocal Corporation. March.

- *Discount and inflation rates.*
- *Tax rates.* Rates for federal and state income taxes, severance taxes, royalty payments, depreciation, and depletion.
- *Price.* Wellhead selling price of oil and gas (also called the "first purchase price" of the product).
- *Drilling cost per well.* Costs for both new production wells and recompletions.
- *Drilling schedule.* Schedule for Cook Inlet, detailing platform-specific drilling activity from 1997 to 2002 for new production wells and recompletions (see Table 4-3 in Chapter Four). Schedule for Major Pass operations varies, as reported by the individual operators.

For some of these categories, values may be common to all Cook Inlet operators while varying among the Major Pass operators; for other categories, values may be common to all Major Pass operators while varying among the Cook Inlet operators. Tables 5-1 and 5-2 summarize some of the values used by EPA in its analysis. Appendix A describes the model parameters and project-specific variables in more detail.

5.1.3 Model Calculation Procedures

The model's calculation procedures include the rules and logic used to convert the common parameters and project variables into measures of a project's financial performance. These procedures fall into several categories: production logic, cost logic, incremental pollution control cost logic, cost accounting practices, price and revenue calculations, earnings and cash flow analysis, and financial performance calculations. Each of these categories is discussed briefly below.

5.1.3.1 Baseline Production Logic

EPA defines a production profile for each operating unit using values for peak, or initial, production rates and production decline rates that were provided by the individual operators or, where individual operator data was missing, estimated these values based on averages for the

TABLE 5-1

SOURCES OF COOK INLET COMMON PARAMETER AND PROJECT-SPECIFIC VARIABLE VALUES FOR THE PRODUCTION LOSS MODEL

Parameter	Value	Source
Real discount rate	8%	Offshore EIA [a].
Inflation rate	3%	Statistical Abstract of the United States (average from 1992 to 1995).
Wellhead price - oil ($/bbl)	$15.91	Marathon Oil Company/Unocal, Zero Discharge Analysis [b], presented to EPA, March 24, 1994, Produced Water section, p. 7; comparable to range seen in survey data; inflated to 1995 $.
Wellhead price - gas ($/Mcf)	$1.72	Scaled from oil price (10.8 percent, see Offshore EIA [a], Table 5-20); comparable to range seen in survey data.
State severance tax - oil	$0.05/bbl	Production tax surcharge of $0.05/bbl. Severance tax is calculated using an Economic Limit Factor (ELF). Because the ELF shelters small fields, Cook Inlet platforms have not paid oil severance tax for several years [c].
Corporate tax rate (federal)	34%	Federal Tax Bracket [d].
Corporate tax rate (state)	Not applicable	Not applicable to Cook Inlet operators.
Percent of drilling costs that may be expensed	42%	Majors may expense 70 percent of their intangible drilling costs (IDCs), and all operators in our Cook Inlet model are majors. IDCs are estimated to account for 60 percent of total drilling costs (Offshore EIA [a]).
Annual production decline rate	8%	Marathon Oil Company/Unocal, Zero Discharge Analysis [b], presented to EPA, March 24, 1994, Produced water section, p. 10.
Initial well production rate (bpd)	500	Marathon Oil Company/Unocal, Zero Discharge Analysis [b], presented to EPA, March 24, 1994, Drilling wastes section, p. 26. Used for new and recompleted wells.
Initial well production rate (Mcf/d)	15,000	Average of Steelhead and Tyonek A per-well production. AOGA presentation to EPA, October 29, 1991 [e].
Well cost - new ($000)	$4,461	EPA's Development Document. Inflated to 1995 $.
Well cost - recompletion ($000)	$1,493	EPA's Development Document. Inflated to 1995 $.

TABLE 5-1 (continued)

Variable	Value	Source
Royalty rate - oil	Varies by lease	Non-confidential operator data [g].
Royalty rate - gas	Varies by lease	Non-confidential operator data [g].
State severance tax - gas	Varies	Calculated using an Economic Limit Factor formula; see Offshore EIA [a].

[a] U.S. EPA. 1993. Economic Impact Analysis of Effluent Guidelines and Standards for Performance for the Offshore Oil and Gas Industry. Washington, D.C. January.

[b] Marathon Oil/Unocal. 1994. "Zero Discharge Analysis: Cook Inlet, Alaska." Marathon Oil Company and Unocal Corporation. March 24.

[c] Logsdon, Charles. 1996. Personal communication between Charles Logsdon, Alaska Department of Revenue, and Cathy Scholz, ERG, dated August 14, 1996, regarding oil and gas taxes in Alaska.

[d] Research Institute of America. 1995. The Complete Internal Revenue Code. Research Institute of America, New York.

[e] Alaska Oil and Gas Association (AOGA). 1991. Produced Water Issues. Handout presented to U.S. EPA. October 29.

[f] U.S. EPA. 1996. Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. Washington, D.C. September.

[g] Section 308 Survey data.

TABLE 5-2

SOURCES OF MAJOR PASS COMMON PARAMETER AND PROJECT-SPECIFIC VARIABLE VALUES FOR THE PRODUCTION LOSS MODEL

Parameter	Value	Source
Real discount rate	7%	Production weighted average for Main Pass Operators reporting a discount rate [a].
Inflation rate	3%	Statistical Abstract of the United States (average from 1992 to 1995).
Corporate tax rate (state)	8%	State Tax Handbook. Does not apply to Main Pass operators in Federal waters [b].
Percent of drilling costs that may be expensed	42% Majors 60% Independents	Majors may expense 70 percent of their intangible drilling costs (IDCs), and independents may expense 100 percent of their intangible drilling costs. IDCs are estimated to account for 60 percent of total drilling costs (Offshore EIA [c]). There are both majors and independents in the Main Pass region.

Variable	Value	Source
Wellhead price - oil ($/bbl)	Varies	Individual operator data [a].
Wellhead price - gas ($/Mcf)	Varies	Individual operator data [a].
Royalty rate - oil	Varies by lease	Individual operator data [a].
Royalty rate -gas	Varies by lease	Individual operator data [a].
State severance tax - oil	Maximum 12.5%	Louisiana severance tax is 12.5%, but individual operators' may receive tax abatements [a,b,d].
State severance tax - gas	Maximum $0.07/Mcf	Louisiana severance tax is $0.07/Mcf, but individual operators' may receive tax abatements [a,b,d].
Corporate tax rate (federal)	34% or 35%	Federal Tax Bracket. Varies by operator [d].
Annual production decline rate	Varies	Individual operator data [a].
Initial well production rate (bpd)	Varies	Individual operator data [a].
Initial well production rate (Mcf/d)	Varies	Individual operator data [a].
Well cost - new ($000)	Varies	Individual operator data [a].
Well cost - recompletion ($000)	Varies	Individual operator data [a].

[a] Major Pass Dischargers Data Submittals (CBI data; in rulemaking record).
[b] Commerce Clearing House, Inc. State Tax Handbook. 1994. Commerce Clearing House, Inc., Chicago, IL.
[c] U.S. EPA. 1993. Economic Impact Analysis of Effluent Guidelines and Standards for Performance for the Offshore Oil and Gas Industry. Washington, D.C. January.
[d] Johnston, Daniel. 1992. Oil Company Financial Analysis in Nontechnical Language. PennWell Publishing, Tulsa, OK.
[e] Research Institute of America. 1995. The Complete Internal Revenue Code. Research Institute of America, New York, NY.

relevant group (i.e., Cook Inlet or Major Pass). Production figures include both current production and increases in production from new and recompleted wells brought online. EPA also calculates summary measures of production for the entire project lifetime.

5.1.3.2 Baseline Cost Logic

EPA uses exogenous cost data to define the yearly capital and operating costs of each project. Exogenous parameters include drilling capital costs, production costs (including existing pollution control costs), and drilling operating costs. The Agency assumes that capital costs for new wells are incurred in the year in which they are drilled. A portion of these costs is expensed for purposes of calculating taxable income. EPA converts all cost information to annual capital and operating cost streams and calculates summary measures (e.g., of all capital and operating costs for the entire project lifetime) using the model.

5.1.3.3 Incremental Pollution Control Cost Logic

A set of equations defined by EPA incorporates the capital and operating costs of additional pollution control approaches into the project cost stream, thus creating a simulation of the economic effects of the various regulatory alternatives. Pollution control costs can include capital and operating costs for disposal of both produced water and drilling wastes. Pollution control capital costs are incurred in the base year (1997) and are capitalized and depreciated for the purposes of calculating taxable income for the year in which they are incurred. EPA analyzes pollution control operating costs in the same way as other operating costs for the project.

5.1.3.4 Cost Accounting Practices

EPA analyzes capital and operating costs and project cost streams in accordance with oil industry accounting practices.[8,9,10,11] The Agency calculates the expensed and capitalized portions of each capital expenditure, then uses these amounts to estimate depreciation and taxable income for each year of the project's lifetime.

5.1.3.5 Price and Revenue Calculations

For the Cook Inlet projects, wellhead prices of oil and gas (exogenous parameters in the model) are based on information provided by the Marathon/Unocal presentation.[12] Wellhead prices for the Major Pass projects are based on information provided by the individual operators.[13] EPA multiplies these prices by the annual production volumes to calculate annual project revenues. Revenues are calculated both as an annual stream and as a present-value-equivalent total for the project's lifetime.

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[8]Johnston, Daniel. 1992. Oil Company Financial Analysis in Nontechnical Language. PennWell Publishing, Tulsa, OK.

[9]Logsdon, Charles. Personal communication between Charles Logsdon, Alaska Department of Revenue, and Cathy Scholz, ERG, dated August 14, 1996, regarding oil and gas taxes in Alaska.

[10]Snook, S.B., and W.J. Magnuson, Jr. 1986. "The Tax Reform Act's Hidden Impact on Oil and Gas." The Adviser. December, pp. 777-783.

[11]Research Institute of America. 1995. The Complete Internal Revenue Code. Research Institute of America, New York, NY.

[12]Marathon/Unocal. 1994. "Zero Discharge Analysis: Cook Inlet, Alaska." Marathon Oil Company and Unocal Corporation. March.

[13]Major Pass Dischargers Data Submittals (CBI data; in rulemaking record).

5.1.3.6 Earnings and Cash Flow Analysis

As part of its analysis, the Agency calculates a project's annual net cash flow from operations (i.e., the difference between a project's revenues and its operating costs). First, severance tax and royalty payments are subtracted from total revenues to calculate annual net revenues. Operating costs (including pollution control operating costs) are then subtracted to calculate earnings, and federal and state corporate taxes are removed to calculate net cash flow from operations. Federal laws dictate EPA's treatment of depreciation, depletion, and expensable capital costs in these calculations (see Appendix A).

A $0.05/bbl tax is applied to oil production in Cook Inlet, and severance taxes on gas production in the Inlet are calculated using an Economic Limit Factor (ELF). Severance taxes for the Major Pass dischargers are based on Louisiana state tax rates and tax abatements, as specified by the individual operators. Tables 5-1 and 5-2 present tax rates and royalty rates.

5.1.3.7 Financial Performance Calculations

EPA calculates a variety of summary financial measures using the model. For Cook Inlet present value calculations, EPA discounted annual project cash flows using an 8 percent real discount rate (i.e., 8 percent after adjusting for inflation). The 8 percent discount rate is both the rate used in the Offshore EIA[14] and the average reported by all Section 308 Survey respondents (Section 308 Survey Questionnaires, Rulemaking Record). For the Major Pass dischargers, EPA discounted annual project cash flows using a 7 percent discount rate, the production weighted average for the Major Pass operations that reported a discount rate to EPA.[15]

[14]U.S. EPA. 1993. Economic Impact Analysis of Effluent Guidelines and Standards of Performance for the Offshore Oil and Gas Industry. Washington, D.C. January.

[15]Major Pass Dischargers Data Submittals (CBI data; in rulemaking record).

In addition to cash flows, EPA's model summarizes lifetime petroleum production (on a total and present value basis), total revenues, total costs, years of production, and average costs per unit of production (calculated as the present value of all project costs divided by the present value of all petroleum production).

The specifics of each of these calculations are given in more detail in Appendix B, which describes the Cook Inlet/Major Pass production loss model.

5.1.4 Interpretation of Model Results

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

- NPV of the project (present value of project net worth from the producer's perspective)
- Total lifetime production (BOE)
- Present value equivalent of production (PVBOE)
- Total years of production
- Economic viability of the project (first-year closure)
- Present value of all project costs
- Present value of all project revenues
- Present value of additional pollution control costs
- Present value of severance tax payments
- Present value of corporate income tax payments
- Present value of royalties
- Corporate cost per unit of production
- Production cost per unit of production

The analysis of the economic status of the baseline case (presented in Section 5.2) focuses on the first few performance measures listed above. The analysis of regulated cases includes comparisons between the base case statistics and regulated (postcompliance) case results.

The *net present value* of the project is calculated as the difference between the present values of all cash inflows and all cash outflows associated with a project (from the perspective of the firm). A positive value indicates that a project generates more revenues than would be realized by investing the capital in a different opportunity with an expected rate of return equal to the cost of capital (discount rate) used in this analysis.

Total lifetime production sums the stream of future petroleum production.

The *present value equivalent of production* is defined as the value of the discounted stream of future petroleum production (i.e., it reflects BOE discounted to the present under the assumption that a barrel of oil today is worth more than a barrel of oil in the future under a constant, real dollar per barrel of oil scenario).

Total years of production is calculated as the number of years the project will operate with a positive cash flow. EPA's model can estimate annual cash flows over a 30-year lifetime. The Agency assumes that a platform will stop producing when operating cash flow becomes negative (i.e., when current variable costs exceed current revenues).[16]

The *corporate cost* per unit of production is defined as the present value of all net corporate cash outflows for the project life (i.e., the cost of operation, royalties, severance tax and income tax payments, with adjustments made for tax savings based on expensed capital expenditures, depreciation, and depletion) divided by the present value of all production (e.g., BOE of oil and gas production). The present value calculations use a cost-of-capital interest rate of 8 percent for the Cook Inlet platforms and 7 percent for the Major Pass dischargers to

[16] In the Cook Inlet/Major Pass model, variable costs consist of the baseline operating costs plus (in postcompliance scenarios) the O&M cost component of pollution control costs. Fixed costs do not play a role in the production decision.

discount costs, cash flow, and production.[17] 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 operation of coastal petroleum projects. In contrast to the corporate cost, the production cost ignores the effect of transfers that do not use social resources, such as income taxes, revenue taxes, and royalties. The present values of all investment costs and operating costs are summed in the calculation of this cost. This sum is divided by the present value equivalent of production to obtain production costs.

5.1.5 Data Sources and Values for Common Parameters and Project-Specific Variables

For all Cook Inlet platforms and Major Pass dischargers, EPA considers previously expended costs (i.e., leasing, exploration, delineation, and platform installation costs) to be sunk costs. Tables 5-1 and 5-2 summarize the common parameter values and some of the project-specific variables used in the models. All costs are in 1995 dollars (or are deflated/inflated to 1995 dollars), and year 1 in the model is 1997, the year the regulation is assumed to go into effect. Pollution control costs are incorporated into the model at the beginning of 1997 because even if the regulation is not effective until mid-1997, partial years cannot be modeled for impacts.

5.1.5.1 Drilling Schedule and Drilling Cost per Well

EPA analysis of the Cook Inlet platforms and Major Pass dischargers incorporates future drilling and production as well as current production. The economic model for each platform

[17]The 8 percent discount rate for Cook Inlet is based on the average for all operators among the Section 308 Survey respondents and is unchanged from analyses used to support the proposal (Section 308 Survey Questionnaires, in rulemaking record). The 7 percent discount rate is the production-weighted average of discount rates reported by the Major Pass dischargers (Major Pass Dischargers Data Submittals [CBI data; in rulemaking record]).

reflects the costs for the new and recompleted wells in the baseline case (i.e., drilling costs and the resultant production increases are included in the economic profile of platforms before compliance costs are incurred).

The planned drilling programs in Cook Inlet are summarized in Chapter Four (see Table 4-3). Drilling is projected to occur from 1997 through 2002. The Agency made three assumptions in developing the drilling schedule from the information submitted to EPA by the Cook Inlet operators:

- The regulation takes effect in 1997.
- Drilling is begun and completed in a 3-month period.
- All wells are drilled in the earliest year possible after 1996, given the planning window (e.g., if the well is to be drilled sometime between 1997 and 1999, the well is assumed to be drilled in 1997). Given the previous assumption, since no more than four rigs are available at any one time to Unocal, Unocal can drill a maximum of 12 wells in any one year.

The drilling schedule and drilling costs for the Major Pass dischargers are based on information provided by the individual operators regarding development plans and expected production from new and recompleted wells.

The model differentiates between drilling costs for new and recompleted production wells. Drilling costs for new wells include costs to drill three segments of a well. Recompletion costs include costs to recomplete the third segment of a well. Section 308 Survey data estimated the per-well cost for new production wells in Cook Inlet to be $4.5 million and the cost for recompletions to be $1.5 million (see EPA's Development Document). Drilling costs applied in the Major Pass analysis vary by operator.

EPA assumes that the oil company elects to expense intangible drilling costs (IDCs) incurred in the development of oil and gas wells. IDCs are estimated, on average, to represent

60 percent of the cost of production wells and their infrastructure.[18,19,20] The Tax Reform Act limits major integrated oil producers to expensing 70 percent of IDCs, with the remaining 30 percent capitalized (i.e., a major may only expense 0.60 times 0.70, or 42 percent of its costs of production wells and infrastructure). The remaining 58 percent of the total cost of production wells and infrastructure is capitalized and depreciated for tax purposes.[21] EPA depreciates these capital costs using the Modified Accelerated Capital Recovery System (MACRS) over a 7-year period (see Appendix A). Once adjustments have been made for all depreciation and tax shield benefits, EPA takes the total capital cost into account in calculating the project NPV.

5.1.5.2 Production Rates

The Agency estimates 1997 production for projects in the Cook Inlet/Major Pass model on the basis of 1995 production rates (see EPA's Development Document). Based on responses to the Section 308 Survey, EPA assumes that the platforms in Cook Inlet (except Steelhead and Tyonek A) consume all gas produced at the platform. Information supplied to EPA by the individual Major Pass operators indicates that all the affected facilities produce and sell both oil and gas.

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[18]U.S. Department of Commerce. 1992. Annual Survey of Oil and Gas, 1980. U.S. Department of Commerce, Bureau of the Census, Current Industrial Reports. MA-13k(80)-1. March.

[19]U.S. Department of Commerce. 1993. Annual Survey of Oil and Gas, 1981. U.S. Department of Commerce, Bureau of the Census, Current Industrial Reports. MA-13k(81)-1. March.

[20]API. 1986. 1984 Survey on Oil and Gas Expenditures. American Petroleum Institute, Washington, D.C. October.

[21]Snook, S.B., and W.J. Magnuson, Jr. 1986. "The Tax Reform Act's Hidden Impact on Oil and Gas." The Tax Adviser. December, pp. 777-783.

5.1.5.3 Baseline Operation and Maintenance Costs per Project

Annual operating costs for oil-producing platforms in Cook Inlet are estimated as the product of 1995 production rates and a per-barrel operating cost. In making this calculation, EPA assumes a per-barrel cost of $7.68, loosely based on approximations of baseline projections provided by the Marathon/Unocal presentation and inflated to 1995 dollars. This figure falls within the range for per barrel O&M costs submitted by Marathon/Unocal.[23] For gas producing platforms, annual operating costs are based on Section 308 Survey data (Section 308 Survey Questionnaires).

Operating costs for the Major Pass projects (which produce both oil and gas) are based on information provided to EPA by individual operators. Each operator's per-BOE cost is multiplied by 1995 production rates (in BOE) to approximate annual costs.

For projects with drilling plans expected to yield substantial additional production relative to current production, the Agency assumes that operating costs will increase relative to the volume of additional oil, gas, and water to be handled by treatment facilities (i.e., the larger volume of produced fluids to process would result in additional operating costs). These additional costs are calculated on a per-BOE basis or, where sufficient information is available, on a marginal cost-per-well basis.

5.1.5.4 Tax Rates

The tax rates used in the model include federal and state corporate tax rates, severance taxes, and royalty payments.

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[23]Marathon/Unocal. 1994. Confidential data provided to U.S. EPA. Document Control Number 1304-1. March 24.

In Cook Inlet, EPA applies a federal corporate tax rate of 34 percent to all operators.[24] Severance taxes are calculated using the ELF. The Alaska Department of Revenue reports that oil wells in Cook Inlet have not incurred severance taxes for several years (see Appendix A for more information); only the gas severance tax is in effect. Royalties are based on nonconfidential Survey data. The same royalty rates are applied to all platforms with the same ownership (e.g., all Unocal platforms have an 11.1 percent royalty on oil production). Royalty rates are presented in Table 5-3 for each of the platforms.

The rates applied to the Major Pass dischargers vary according to information provided by the individual operators. Federal corporate tax rates vary between 34 and 35 percent. Projects in Louisiana waters are also subject to a state corporate tax of 8 percent and state severance taxes, which differ from operator to operator. Royalties are based on lease ownership.

Using the model, EPA adjusts earnings to taxable income according to tax regulations that permit expensing and depreciation of certain capital expenditures and depletion of wasting assets. Depreciation for capital expenditures is based on MACRS (details are provided in Appendix A). Depletion of oil and gas reserves can be calculated on either a cost or a percentage basis, depending on whether the project is owned by a major (integrated) or independent oil company. Independent oil companies have the option of calculating depletion using either method. Percentage depletion, which allows a company to write off 15 percent of taxable revenues up to and including 1,000 bpd oil or 6,000 Mcf gas per day per lease of production, generally yields higher values. EPA therefore assumes that independent Major Pass producers use percentage depletion. Major oil companies must use the cost basis for depletion. This method of calculating depletion permits deduction of the leasehold cost over the production

[24]As discussed in Appendix A, operators with taxable income between $100,000 and $1 millon annually are subject to the 34 percent federal tax rate. For simplicity in the proposal, EPA assumed all projects were subject to a 34 percent tax rate. EPA received no comments regarding its use of the 34 percent tax rate in analysis of Cook Inlet operators for either the Offshore Guidelines (Offshore EIA) or the proposed Coastal Guidelines (PEIA). Some of the Major Pass operators, however, specifically indicated that they are subject to the 35 percent tax rate applicable for corporations with taxable income greater than $1 million annually. In analysis of these operators, the 35 percent tax rate is used. The use of 35 percent rather than 34 percent makes very little difference in the analysis, except that it very slightly increases baseline NPV and decreases baseline federal tax receipts.

TABLE 5-3

SUMMARY OF COOK INLET PLATFORM DATA AND INPUTS [a]

Platform	Owner	Treatment Facility	Oil Production 1995 data bpd	Oil Production Estimated 1997 bpd	Gas Production 1995 data bpd	Gas Production Estimated 1997 bpd	Estimated Operating Costs ($000)	Royalty Oil	Royalty Gas
SWEPI A & C	Shell Western	E. Foreland	5,000	4,232	0	0	$14,020	12.5%	0.0%
Granite Point	Unocal	Granite Point	6,086	5,151	0	0	$17,066	11.1%	0.0%
Dolly	Unocal	Trading Bay	4,983	4,218	0	0	$13,973	12.7%	0.0%
Grayling	Unocal	Trading Bay	5,207	4,407	0	0	$14,601	11.1%	0.0%
King Salmon	Unocal	Trading Bay	3,864	3,270	0	0	$10,835	11.1%	0.0%
Steelhead	Unocal	Trading Bay	4,184	3,541	165,000	139,656	NA	12.7%	12.0%
Monopod	Unocal	Trading Bay	1,981	1,677	0	0	$5,555	11.1%	0.0%
Baker	Unocal	Platform	1,301	1,101	0	0	$3,648	11.1%	0.0%
Dillon	Unocal	Platform	841	712	0	0	$2,358	11.1%	0.0%
Anna	Unocal	Platform	3,117	2,638	0	0	$8,740	11.1%	0.0%
Bruce	Unocal	Platform	865	732	0	0	$2,426	11.1%	0.0%
Tyonek "A"	Phillips	Platform	0	0	220,000	186,208	NA	0.0%	12.0%

[a] This table summarizes Cook Inlet data only because much of the information EPA used for the Major Pass operators was claimed to be confidential business information.

Notes:

Annual decline rate of 8% used in conjunction with 1995 production data to estimate 1997 production.
Except for Tyonek A and Steelhead, all gas produced is assumed to be consumed at the platform.
Operating costs based on 1995 production (bbl or boe), unless later wells or recompletions result in higher production rate.
Operating costs based on estimated cost of $7.68/bbl.
NA: Not available due to confidentiality of survey data (see Cook Inlet and Major Pass Parameters and Assumptions -- CBI data; in rulemaking record).

Source: Major Pass and Cook Inlet Parameters and Assumptions (CBI data; in rulemaking record).

lifetime of the project according to the proportion of total reserves sold in each given year. Because EPA assumes all prior investments to be sunk costs, and thus not a part of this analysis, no basis exists for estimating depletion for the major oil companies operating in Cook Inlet and the Major Pass regions. This omission leads to a slight underestimate of the profitability of these projects in the baseline analysis (which is offset by the exclusion of sunk costs in estimating profitability). Omitting depletion has little to no effect on the incremental impact analysis. The two methods of depletion are discussed further in Appendix A.

5.1.5.5 Prices

The wellhead prices of oil and gas in Cook Inlet are presented in Table 5-1. The value for oil, $15.91 per barrel in 1995 dollars, is inflated from data provided by the Marathon/Unocal presentation. Average rates from the Section 308 Survey database are comparable. The wellhead price of gas is scaled to 10.8 percent of the price of oil (Offshore EIA), and the resultant figure of $1.72/Mcf is also comparable to data from the Section 308 Survey (Section 308 Survey). Wellhead prices for the Major Pass dischargers are based on individual operator data.

5.1.6 Calculation Procedures

5.1.6.1 Production Logic

To determine total production at a platform or facility, EPA begins with estimates of 1997 production, as discussed above, and assumes that peak production rates occur in the first year of production and are maintained for the first year only. The subsequent pattern of decline in a well's productivity varies greatly due to many factors. Production decline is modeled as an exponential function (i.e., a constant percentage of the remaining reserves produced in any given year). In Cook Inlet, EPA assumes that oil and gas production declines by 8 percent annually, a value typical for that region (Marathon/Unocal presentation). The Agency uses project-specific decline rates provided by the individual operators to model the Major Pass dischargers.

EPA also includes increases in production originating with recompleted or new production wells in its analysis. In Cook Inlet, when a company drills new wells or recompletes existing wells, production increases of 500 barrels of oil per day (Marathon/Unocal presentation) or 15,000 Mcf of gas per day[25] per well are added to existing production figures. The corresponding production increases for the Major Pass dischargers vary by operator. Some Major Pass operators reported specific drilling plans in conjunction with per-well expected increases, while others reported drilling expenditures on an aggregate level in conjunction with production increases based on likely drilling success rates.

5.2 PRODUCTION LOSS MODELING RESULTS[26]

This section presents the results of the production loss modeling for Cook Inlet platforms and Major Pass facilities potentially affected by the proposed guidelines (i.e., operations not covered by the Region 6 permit). EPA calculates summary statistics for both baseline and postcompliance scenarios, broken down by region. Postcompliance results include, by option, numbers of first-year shut-ins of wells, platforms, or facilities; production losses; years of production lost; net present dollar value of production losses; and state and federal revenues lost. Impacts on each of the groups are described first separately and then in aggregate.

[25]Alaska Oil and Gas Association (AOGA). 1991. Produced Water Issues. Handout presented to U.S. EPA. October 29.

[26]All results shown in the text and tables in Section 5.2 are based on Cook Inlet and Major Pass Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

5.2.1 Produced Water/Treatment, Workover, and Completion Wastes[27]

5.2.1.1 Cook Inlet[28]

Baseline (Current Practice)

Currently there are thirteen platforms operating in Cook Inlet. EPA estimates that these thirteen platforms will produce 311.3 million discounted BOE (501.1 million total BOE) over their combined lifetime without any further regulatory action. All thirteen are expected to operate for at least one year; the Agency's analysis shows none closing in the baseline. EPA further estimates that, in combination, the Cook Inlet platforms will operate for a total of 152 platform-years, or 12.7 years on average. The NPV of this combined lifetime production (i.e., the present value of projected revenues minus cash outflows [operating costs, capital expenditures, and taxes] associated with Cook Inlet projects) is $838.6 million. The present value of severance taxes collected is estimated at $146.7 million, the present value of royalties to the state is $434.9 million, and the present value of federal income taxes collected is $446.6 million. Table 5-4 summarizes baseline and postcompliance results.

Options #1 and #2 (Gas Flotation)

Both Options #1 and #2 require Cook Inlet platforms to meet offshore limits (i.e., improved gas flotation). Although the Agency does not expect any platforms to shut in in the first year, EPA analysis of production in Cook Inlet suggests that use of gas flotation would result in total lifetime production dropping by 1.1 million discounted BOE to 310.2 million discounted BOE (equal to a loss of 2.4 million total BOE). This loss amounts to approximately

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[27]TWC wastes are discussed in conjunction with produced water because operators generally combine these wastes. The guidelines for TWC are therefore the same as those for produced water, and there are no incremental costs associated with TWC disposal (beyond the costs for produced water) in Cook Inlet. There are, however, small incremental costs associated with TWC disposal for NSPS and BAT in the Gulf region.

[28]All results shown in the text and tables in Section 5.2.1.1 are based on Cook Inlet Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

TABLE 5-4

IMPACTS OF PRODUCED WATER OPTIONS
ON COOK INLET PLATFORMS (1995 $)

Type of Impact	Baseline Current Practice	Gas Flotation Options #1 and #2	Zero Discharge Option #3
Projected lifetime discounted production (PVBOE)	311,318,836	310,246,742	301,852,447
Change in discounted production (PVBOE)	—	1,072,094	9,466,390
Percentage change in discounted baseline production	—	0.3%	3.0%
Total projected lifetime production (BOE)	501,066,400	498,662,817	481,663,447
Change in total projected lifetime production (BOE)	—	2,403,582	19,402,953
Percentage change in discounted baseline production	—	0.5%	3.9%
Present value of project net worth (NPV) ($000)	$838,618	$826,735	$683,863
Change in NPV ($000)	—	$11,883	$154,755
Percentage change in NPV	—	1.4%	18.5%
Number of platforms ceasing production in first year (postcompliance)	0	0	1
Total number of production years (1997 on)	152	148	125
Average production years per platform (all platforms)	12.7	12.3	10.4
Average production years per platform (nonclosing platforms)	12.7	12.3	11.4
Total production years lost among closing platforms	—	0	6
Total production years lost among nonclosing platforms	—	4	21
Present value of severance and state income taxes collected ($000)	$146,730	$146,676	$146,256
Change in present value of severance and state income taxes ($000)	—	$54	$473
Percentage change in severance and state income taxes	—	0.0%	0.3%
Present value of federal income taxes collected ($000)	$446,615	$441,644	$378,796
Change in present value of federal income taxes ($000)	—	$4,971	$67,820
Percentage change in federal income taxes	—	1.1%	15.2%
Present value of royalties collected ($000)	$434,946	$432,955	$417,383
Change in present value of royalties ($000)	—	$1,991	$17,563
Percentage change in royalties	—	0.5%	4.0%

Source: Cook Inlet Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

0.3 percent of lifetime discounted production in Cook Inlet. The average number of production years per platform also drops from 12.7 to 12.3, indicating that the installation and operation of improved gas flotation equipment would result in platforms shutting in an average of 5 months earlier than they would have without the regulation.

EPA further estimates that the NPV of the Cook Inlet projects would drop $11.9 million to $826.7 million, a 1.4 percent loss of baseline net present value among all Cook Inlet projects. This reflects both lost production and capital and O&M costs of compliance. The total present value of lifetime federal income taxes lost under this option is estimated to be $5.0 million, or 1.1 percent of the baseline federal taxes estimated to be collected over the life of the platforms. The present value of severance taxes lost amounts to $54,000 over the life of the platforms. Royalties lost to the state total $2.0 million in present value terms over the life of the platform, or 0.5 percent of the baseline royalties collected (see Table 5-4).

Option #3 (Zero Discharge)

Option #3 requires that the Cook Inlet platforms meet zero-discharge requirements with respect to produced water. Under a zero-discharge requirement, EPA analysis indicates that one platform would shut in (cease production) during the first year, and Cook Inlet lifetime production would drop by 9.4 million discounted BOE (19.4 million total BOE), or 3.0 percent of baseline production. Project NPV is estimated to drop by $154.8 million, which is 18.5 percent of baseline NPV. The average productive life of the platforms among those remaining active is 11.4 years, or a loss of 0.7 years per platform.

In addition, the EPA estimates that, under this option, a total of $67.8 million (present value) would be lost in federal income taxes over the lifetime of the Cook Inlet platforms, or 15.2 percent of projected income tax receipts in the baseline. The present value of severance taxes lost is estimated to be $473,000 over the lifetime of the Cook Inlet platforms, or 0.3 percent of total baseline severance taxes estimated to be collected. Loss in royalty payments to the state (in present value terms) would total $17.6 million over the life of the platforms, or 4.0 percent of baseline royalties collected (see Table 5-4).

5.2.1.2 Major Pass Dischargers[29]

Baseline (Current Practice)

Table 5-5 summarizes the baseline and postcompliance scenarios for the Major Pass dischargers. Currently, there are eight facilities associated with oil and gas production and offshore produced water discharge in the Major Pass region. None of these facilities shut in at baseline. EPA estimates that, in combination, the Major Pass dischargers will produce 434.7 million lifetime discounted BOE (599.9 million total BOE). The present value of these Major Pass projects in baseline is $1,459.6 million. The productive lifetimes of the Major Pass dischargers total 82 years, an average of 10.3 years per facility. In addition, the present value of federal income tax collected over the economic lifetime of the operations is estimated at $752.8 million, the present value of severance and state income tax collected is $399.4 million, and the present value of total royalties paid to states and other leaseholders is $815.9 million.

Option #1 (Gas Flotation)

Under Option #1, the Major Pass dischargers would be required to meet limits equivalent to those for offshore operations to discharge offshore water into a major pass of the Mississippi River. EPA analysis indicates that this requirement would not result in any shut-ins. In addition, the Agency projects that use of gas flotation would not result in losses in either lifetime discounted (or total, non-discounted) BOE production or the total number of production years (see Table 5-5).

The gas flotation option is estimated to result in a loss of $2.5 million in the NPV of the discharging Major Pass projects (a 0.2 percent drop from baseline to $1,457.0 million). The loss in present value federal income taxes collected associated with gas flotation is $832,000, or 0.1 percent of baseline. Present value state tax losses amount to $168,000, or 0.04 percent of total baseline state severance and income taxes. Neither severance taxes nor royalties are lost because

[29]All results shown in the text and tables in Section 5.2.1.2 are based on Major Pass Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

TABLE 5-5

IMPACTS OF PRODUCED WATER OPTIONS
ON MAJOR PASS FACILITIES (1995 $)

Type of Impact	Baseline Current Practice	Gas Flotation Option #1	Zero Discharge Options #2 and #3
Projected lifetime discounted production (PVBOE)	434,713,377	434,713,377	432,592,658
Change in discounted production (PVBOE)	---	0	2,120,719
Percentage change in discounted baseline production	---	0.0%	0.5%
Total projected lifetime production (BOE)	599,860,713	599,860,713	596,461,487
Change in total projected lifetime production (BOE)	---	0	3,399,226
Percentage change in discounted baseline production	---	0.0%	0.6%
Present value of project net worth (NPV) ($000)	$1,459,603	$1,457,042	$1,407,790
Change in NPV ($000)	---	$2,560	$51,812
Percentage change in NPV	---	0.2%	3.5%
Number of facilities ceasing production in first year (postcompliance)	0	0	0
Total number of production years (1997 on)	82	82	79
Average production years per facility (all facilities)	10.3	10.3	9.9
Average production years per facility (nonclosing facilities)	10.3	10.3	9.9
Total production years lost among closing facilities	---	0	0
Total production years lost among nonclosing facilities	---	0	3
Present value of severance and state income taxes collected ($000)	$399,427	$399,259	$393,363
Change in present value of severance and state income taxes ($000)	---	$168	$6,063
Percentage change in severance and state income taxes	---	0.0%	1.5%
Present value of federal income taxes collected ($000)	$752,818	$751,987	$737,530
Change in present value of federal income taxes ($000)	---	$832	$15,289
Percentage change in federal income taxes	---	0.1%	2.0%
Present value of royalties collected ($000)	$815,892	$815,892	$809,434
Change in present value of royalties ($000)	---	$0	$6,458
Percentage change in royalties	---	0.0%	0.8%

Source: Major Pass Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

these are calculated based on BOE produced and Option #1 is not associated with losses in production (see Table 5-5).

Options #2 and #3 (Zero Discharge)

Under Options #2 and #3, the Major Pass dischargers are required to convert to zero discharge of produced water. Although no facilities would shut in as a result of this requirement, EPA estimates that total lifetime production from the Major Pass dischargers would drop 2.1 million discounted BOE to 432.6 million discounted BOE (a loss of 3.4 million total, non-discounted BOE). The NPV of projects in this group is estimated to decrease by $51.8 million to $1,407.8 million (3.5 percent).

In addition, EPA analysis shows that the total number of production years for the Major Pass dischargers would drop by 3 years to 79 years (an average of 10.3 production years dropping to 9.9 production years per facility) under zero discharge. The present value of federal income taxes lost is $15.3 million, or 2.0 percent of the baseline federal taxes estimated to be collected over the lifetime of the facilities. Present value state and severance taxes collected is reduced by $6.1 million, or 1.5 percent of baseline, and royalties lost are estimated at $6.5 million (in present value terms), or 0.8 percent of baseline.

5.2.2 Drilling Wastes[30]

Option #1 (Current Practice)

Option #1 requires Cook Inlet operators to meet requirements equivalent to those in the Oil and Gas Industry Offshore Guidelines and all other operators to practice zero discharge. Current drilling waste practices meet these requirements; Cook Inlet platform discharges are

[30]All results shown in the text and tables in Section 5.2.2 are based on Cook Inlet Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

within offshore discharge limitations, and all other areas of the country practice zero discharge. As such, Option #1 is a no-cost option. Baseline numbers for Cook Inlet, as indicated in Table 5-6, are the same as those in Table 5-4.

Option #2 (Zero Discharge–Landfill)

Under Option #2, coastal oil and gas operators are required to achieve zero discharge of drilling waste. EPA assumes the Cook Inlet operators do this by sending their drilling waste to a landfill. The Agency investigated a less expensive option but did not model it because of concerns that this alternative was not technically feasible. Table 5-6 summarizes the impacts of this option on Cook Inlet, the only area of the United States (outside of offshore regions) not currently practicing zero discharge of drilling wastes. Under this option, no platforms shut in during the first year, and there are no losses in total lifetime production. Furthermore, since production levels do not change between the baseline and postcompliance scenarios, there are no losses in royalties or severance taxes collected.

Option #2 is associated with a $32.5 million decrease in the NPV of Cook Inlet projects, or a 3.9% loss compared to baseline NPV. The present value of federal income taxes collected drops $16.4 million, as well (3.7% of baseline federal taxes collected).

5.2.3 Combined Impacts (Cook Inlet and Major Pass)[31]

EPA examined the impacts of each produced water and drilling waste option on the Cook Inlet platforms and the Major Pass discharging facilities combined.

As Table 5-7 shows, total produced water impacts for the Cook Inlet and Major Pass operators tend to increase with option number. In particular, Option #3, which requires both groups to go to zero discharge, shows a large incremental change in impacts from Option #2,

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[31]Unless otherwise noted, results shown in the text and tables in Section 5.2.3 are based on Cook Inlet Dischargers Production Loss Model Runs and Major Pass Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

TABLE 5-6

IMPACTS OF DRILLING WASTE OPTIONS ON COOK INLET PLATFORMS (1995 $)

Type of Impact	Baseline Option #1	Landfill Option #2
Projected lifetime discounted production (PVBOE)	311,318,836	311,318,836
Change in discounted production (PVBOE)	---	0
Percentage change in discounted baseline production	---	0.0%
Total projected lifetime production (BOE)	501,066,400	501,066,400
Change in total projected lifetime production (BOE)	---	0
Percentage change in discounted baseline production	---	0.0%
Present value of project net worth (NPV) ($000)	$838,618	$806,118
Change in NPV ($000)	---	$32,500
Percentage change in NPV	---	3.9%
Number of platforms ceasing production in first year (postcompliance)	0	0
Total number of production years (1997 on)	152	152
Average production years per platform (all platforms)	12.7	12.7
Average production years per platform (nonclosing platforms)	12.7	12.7
Total production years lost among closing platforms	---	0
Total production years lost among nonclosing platforms	---	0
Present value of severance and state income taxes collected ($000)	$146,730	$146,730
Change in present value of severance and state income taxes ($000)	---	$0
Percentage change in severance and state income taxes	---	0.0%
Present value of federal income taxes collected ($000)	$446,615	$430,225
Change in present value of federal income taxes ($000)	---	$16,391
Percentage change in federal income taxes	---	3.7%
Present value of royalties collected ($000)	$434,946	$434,946
Change in present value of royalties ($000)	---	$0
Percentage change in royalties	---	0.0%

Source: Cook Inlet Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

TABLE 5-7

TOTAL IMPACTS OF PRODUCED WATER OPTIONS (1995 $)

(COOK INLET PLATFORMS AND MAJOR PASS FACILITIES)

Type of Impact	Option #1		Option #2		Option #3	
	Loss	Percent of Baseline Lost	Loss	Percent of Baseline Lost	Loss	Percent of Baseline Lost
Number of platforms/facilities shut in	0	NA	0	NA	1 Platform	NA
Discounted lifetime production lost (PVBOE)	1,072,094	0.1%	3,192,814	0.4%	11,587,109	1.6%
Total lifetime production lost (BOE)	2,403,582	0.2%	5,802,808	0.5%	22,802,179	2.1%
Present value of project net worth lost (NPV) ($000)	$14,444	0.6%	$63,696	2.8%	$206,567	9.0%
Present value of severance and state income taxes lost ($000)	$222	0.0%	$6,117	1.1%	$6,537	1.2%
Present value of federal income taxes lost ($000)	$5,803	0.5%	$20,260	1.7%	$83,108	6.9%
Present value of royalties collected ($000)	$1,991	0.2%	$8,449	0.7%	$24,021	1.9%
Total present value losses (including compliance costs) ($000)	$22,460	0.4%	$98,522	1.9%	$320,234	6.0%

Source: Cook Inlet Dischargers Production Loss Model Runs and Major Pass Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

which requires zero discharge from the Major Pass facilities but allows continued discharge from the Cook Inlet platforms provided that gas flotation limits are met. Total losses from Option #3 are higher because, as discussed in Section 5.2.1, zero-discharge requirements in Cook Inlet are associated with higher costs and the closure of one platform.

Regulatory impacts increase further when the produced water options are analyzed in conjunction with zero discharge of drilling wastes. In Cook Inlet, the use of gas flotation for produced water (Option #2) in combination with zero discharge of drilling wastes (Option #2) is associated with a slight drop in NPV and federal and state taxes collected, although no production is lost. If Option #3 for produced water is combined with Option #2 for drilling wastes (the zero-discharge/zero-discharge scenario), EPA analysis indicates that four of the thirteen platforms in Cook Inlet would shut in. Losses in production, NPV, severance taxes and royalties, and state and federal income taxes collected all are incurred under this scenario.

TWC wastes, as noted above, are discussed in this FEIA in conjunction with produced water because operators generally combine these wastes. Hence impacts associated with the various produced water options tend to encompass the impacts of the TWC options. However, in certain operations not examined above, TWC waste disposal costs may apply. Costs of disposing of TWC under a zero-discharge option are $0.6 million annually (see Chapter Four of this FEIA) for all Gulf of Mexico wells estimated to discharge TWC (a minimum of 334 wells; see EPA's Development Document), or an average of $1,796 per well. A typical Gulf of Mexico well produces an average of 36 barrels of oil per day according to the Section 308 Survey Questionnaires. At $19.75 per barrel (the Section 308 Survey Questionnaire average inflated to 1995 dollars), EPA estimates that total gross production revenue at a typical well is $260,000 per year. Thus, under a zero discharge option, TWC disposal costs are estimated to be 0.7 percent of annual gross production revenues at a typical Gulf of Mexico well. These TWC costs add negligibly to the impacts discussed earlier.

5.2.3.1 Combined Impacts -- Selected Options[32]

EPA's selected regulatory options are Produced Water Option #2 and Drilling Waste Option #1. Table 5-8 shows the total maximum impacts from these selected options. Since Drilling Waste Option #1 is a no-cost option, the impacts in Table 5-8 are the same as those indicated in Tables 5-7. Disposal of TWC wastes involves negligible additional impacts.

Under Option #2/Option #1, the Cook Inlet platforms and Major Pass dischargers experience no incremental shut-ins. EPA estimates total maximum impacts as follows: production losses of 3.2 million discounted BOE (5.8 million total BOE), which amounts to 0.4 percent of projected discounted baseline production in Cook Inlet and the Major Passes, or 0.2 percent of projected discounted baseline production from all coastal oil and gas operations outside of California and North Slope, Alaska; and total present value losses of $99.0 million (1.9 percent of the total NPV, taxes, and royalties in Cook Inlet and the Major Passes, or 0.7 percent of the total NPV, taxes, and royalties associated with total coastal production outside of California and North Slope). The latter figure represents losses of $63.7 million in project NPV, $6.1 million in present value severance and state income taxes, $20.3 million in present value federal taxes, and $8.4 million in present value royalties (see Table 5-8). Note that production losses would have additional effects on other parts of the economy. These effects are discussed in Chapter Seven.

[32]Unless otherwise noted, results shown in the text and tables in Section 5.2.3.1 are based on Cook Inlet Dischargers Production Loss Model Runs and Major Pass Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

TABLE 5-8

IMPACTS OF SELECTED OPTIONS (1995 $)
(COOK INLET PLATFORMS AND MAJOR PASS FACILITIES)

Type of Impact	Produced Water Option #2	Drilling Waste Option #1	Total Impacts	Percent of Baseline Lost	Percent of Total Coastal Lost [a]
Number of platforms/facilities shut in	0	0	0	NA	NA
Discounted lifetime production lost (PVBOE)	3,192,814	0	3,192,814	0.4%	0.2%
Total lifetime production lost (BOE)	5,802,808	0	5,802,808	0.5%	0.2%
Present value of project net worth lost (NPV) ($000)	$63,696	$0	$63,696	2.8%	1.4%
Present value of severance and state income taxes lost ($000)	$6,117	$0	$6,117	1.1%	0.3%
Present value of federal income taxes lost ($000)	$20,260	$0	$20,260	1.7%	0.9%
Present value of royalties collected ($000)	$8,449	$0	$8,449	0.7%	0.2%
Total present value losses (including compliance costs) ($000)	$98,522	$0	$98,522	1.9%	0.7%

[a] The calculation of estimates for total Gulf coastal baseline production, NPV, state and severance tax paid, federal tax paid, and royalties is discussed in: Jones, Anne, ERG, Memorandum to Matt Clark, U.S. EPA, dated August 2, 1996, entitled "Approximation of Total NPV, Taxes, Royalties, and Severance in the Gulf Coastal Region (All Operators)."

For this table, Cook Inlet baseline estimates were added to the Gulf estimates. Total coastal figures do not include coastal operations in California or North Slope, Alaska.

Sources: Cook Inlet Dischargers Production Loss Model Runs and Major Pass Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

CHAPTER SIX

FIRM-LEVEL ECONOMIC IMPACTS ON THE COASTAL OIL AND GAS INDUSTRY

The firm-level analysis evaluates the effects of regulatory compliance on firms owning one or more affected coastal oil and gas operations. It also serves to identify impacts not captured in the production loss analysis. For example, some companies might be too weak financially to undertake the investment in the required effluent control, even though the investment might seem financially feasible at the facility or platform level. The Section 308 Survey and EPA's later data collection effort among the Major Pass operators asked respondents for financial data from the lowest level of organization at which assets, liabilities, and taxes are clearly identifiable. Thus, the financial data should reflect the most financially sensitive level of organization (e.g., a division of a major company rather than all corporate holdings, if the division acts as a profit center).

EPA's firm-level analysis consists of three steps. In the first step, the Agency conducts a baseline analysis to determine which firms might fail even if the Coastal Guidelines are not promulgated. In the second step, EPA examines the firms' equity and working capital to determine which operators could not comfortably cover annual compliance costs (i.e., where annual compliance costs both exceed 5 percent of working capital and 5 percent of equity). EPA then examines, in depth, the finances of operators for whom annual compliance costs exceed 5 percent of working capital and 5 percent equity to determine whether any potential major impacts are likely to materialize.

6.1 ANALYTICAL METHODOLOGY

6.1.1 Baseline Methodology

EPA uses a cash-flow analysis to determine whether any firms are likely to be considered baseline failures (i.e., whether any firms are highly likely to fail regardless of the regulation under consideration because their financial health is so precarious). For the Major Pass and Cook Inlet operators, EPA considers positive after-tax cash flow or net income (if cash flow information was not available) as reported by the operators (1995 data)[1] or in OGJ (OGJ 200)[2] to be an indicator of adequate baseline financial health.

6.1.2 Postcompliance Analysis

In the postcompliance analysis, EPA identifies firms at which impacts from compliance with the regulation are likely to be significant. Equity and working capital are common measures of a firm's ability to afford new projects, acquisitions, etc. Equity is measured as a firm's total assets minus its total liabilities (i.e., its net worth). Working capital is a measure of a firm's liquidity and is measured as current assets (typically cash or near-cash assets that can easily be liquidated) minus current liabilities, which are debts or other obligations due within one year. In other words, working capital describes available cash. If the annual cost of complying with a zero discharge or other requirement contributes to a small percentage change in equity and working capital at a firm, EPA considers it likely that impacts at the firm will not be substantial (i.e., the firm is not likely to fail as a result of compliance).[3]

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[1]Major Pass Dischargers Data Submittals (CBI data; in rulemaking record).

[2]"OGJ 200," Oil and Gas Journal (OGJ), Vol. 94, No. 36, September 2, 1996, pp. 56-74.

[3]Working capital is not considered an issue for the major integrated oil companies. Occasionally these firms have low or negative working capital, but this appears to have no ill effects on their financial health. Thus, change in equity is the measure used for majors. Since working capital is a much more critical source of financing at small independents, EPA is more concerned with changes in working capital at small firms.

EPA identifies firms needing further analysis on the basis of whether the firm would experience a greater than 5 percent change in equity and working capital. In this more detailed analysis (assuming all other things equal), EPA makes adjustments to the firm's cashflow statement, including baseline operating costs, depreciation, and interest using the conservative assumption that the firm will choose to finance pollution control costs out of debt, not equity. EPA adds pollution control operating costs to baseline operating costs, the depreciation allowance on the incremental capital expenditure (straight-line assumed for simplicity) to baseline deprecation, and the associated first-year interest payment to baseline interest using the affected operator's reported discount rate. EPA then determines whether after-tax cash flow is still positive. EPA also estimates the magnitude of first-year the declines in after-tax cash flow compared to baseline, and the declines over 10 years in present value terms (assuming all other revenues and costs remain constant both in the baseline and the postcompliance scenarios). As a complement to the cash flow analysis, EPA investigates each firm's financial health to determine if the firm appears capable of raising the capital needed to purchase and install the necessary pollution control equipment. Firm failure is not considered likely if capital will be available to purchase and install equipment (e.g., if the firm has an available credit line that can easily accommodate the additional capital requirements).

6.2 SOURCES OF DATA

EPA obtained 1995 data for Cook Inlet operators from financial data published in OGJ (OGJ 200) (see Chapter Three). For the Major Pass analyses, EPA contacted potentially affected operators directly for information and supplemented this information with annual and/or quarterly reports, where available. All but one Major Pass operator provided EPA with the necessary financial data. The one firm that did not provide data stated that compliance costs would have no material effect on its financial condition.

6.3 RESULTS OF FIRM-LEVEL ANALYSIS

As discussed in Section 6.1, the results of three levels of analysis are presented here. Section 6.3.1 presents the results of the baseline analysis, and Section 6.3.2 presents the results of the postcompliance analysis, including the screening analysis and the detailed analysis. Results are not discussed in detail to protect data confidentiality for the few firms that provided confidential data.

6.3.1 Baseline Analysis

Six Major Pass firms and three Cook Inlet firms are potentially affected by the Coastal Guidelines. Given cash flow results based on OGJ (OGJ 200) and data collected from the Major Pass operators (including most recent quarterly reports), EPA anticipates no baseline failures among either the Major Pass or Cook Inlet operators (i.e., all firms reporting financial information show positive cash flow). More detailed information is not provided here because of confidentiality issues.

6.3.2 Postcompliance Analysis

EPA anticipates that compliance with regulatory options would cause no firm failures among Major Pass or Cook Inlet firms. Annual pollution control costs for one or more of the firms that provided EPA with financial data exceed the 5 percent benchmark for equity and working capital (independents only) under Options #2 and #3 for produced water/TWC (i.e., these firms' annual compliance costs are greater than 5 percent of their equity and 5 percent of their working capital), but no firms fail a cash flow analysis under these options. All have only small declines in first-year and 10-year present value after-tax cash flow.[4] Furthermore, after more in-depth analysis of credit line availability and capital investment plans, EPA considers all

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[4]Cash Flow Analysis of Major Pass Dischargers (CBI data; in rulemaking record). Percentage declines are not reported to protect confidential business information.

firms likely to be able to raise the necessary capital to meet zero discharge requirements (note that operating costs are not a major issue, since these operations can absorb the increased costs of production with little to no effect, as shown in Chapter Five). Thus EPA expects no firm failures as a result of the Coastal Guidelines (see Chapter Ten for an analysis of firm impacts under an alternative baseline assumption).

Note that a finding of no firm failure does not mean that there will be no impacts on these firms. Rather, it means that EPA does not expect the impacts to be so severe as to cause the firms in question to fail.

CHAPTER SEVEN

REGIONAL AND NATIONAL EMPLOYMENT IMPACTS AND TOTAL OUTPUT LOSSES

This chapter of the FEIA assesses the employment impacts of the Coastal Guidelines on both regional and national levels. It also discusses output losses to the national economy induced by revenue losses in the oil and gas industry. Only impacts from BAT options are discussed here.[1] Chapter Nine discusses impacts from NSPS options, and Chapter Ten discusses impacts under an alternative baseline.

The employment analysis is divided into national- and regional-level analyses. The national-level analysis addresses the net gain or loss of employment resulting from the Coastal Guidelines throughout the United States, whereas the regional-level analysis addresses the effects of employment dislocations (layoffs) in the regional economy where the coastal industry is located. Employment losses and gains will occur throughout the economy in response to a reallocation of expenditures caused by implementation of the Coastal Guidelines. Pollution control expenditures divert investment from oil and gas production, which leads to direct oil and gas employment losses, as well as oil and gas production losses. These losses are offset by gains in employment in the manufacturing firms that produce the pollution control equipment and gains in employment associated with installing and operating the equipment. Gains and losses occur within the oil and gas industry as a result of investment reallocation.

Employment gains may or may not occur in the same region as employment losses but, on a national level, gains will more or less offset losses, with the exception of "dead weight losses"[2] or losses in production efficiency. To compute national-level employment changes, output effects must be considered. Typically, output is measured as revenues. Oil and gas

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[1]There are no costs associated with BCT, PSES, or PSNS, as explained in Chapter Four of this FEIA.

[2]Lost economic productivity that will not be replaced (i.e., that is not a transfer payment to another economic sector).

production losses become revenue losses to the oil and gas industry, which affect the revenues of input industries (industries that supply goods and services to the oil and gas industry), which in turn eventually result in a reduction of household consumption by workers in these industries, decreasing demand for products at the national level. Impacts on the oil and gas industry are known as direct effects, impacts that continue to resonate through the economy are known as indirect effects (effects on input industries), and effects on consumer demand are known as induced effects. These effects are tracked both nationally and regionally in massive "input-output" (I-O) tables prepared by the U.S. Department of Commerce's Bureau of Economic Analysis (BEA). For every dollar spent in a "spending industry," these tables identify the portion spent in contributing or vendor industries.

For example, as a result of this rule, an oil and gas firm might purchase equipment to meet standards equivalent to improved gas flotation. One piece of this equipment could be a tank to hold produced water. To make the tanks, the manufacturer would purchase stainless steel. The steel manufacturer would purchase iron ore, coke, energy sources, and other commodities, etc. Thus a portion of a dollar spent by the oil and gas industry becomes a smaller portion of a dollar spent by the tank manufacturer, and a smaller portion of a dollar spent by the steel manufacturer, and so on. These iterations are captured in the BEA's I-O tables and summarized as regional and national multipliers for output (revenues). BEA also has determined average wages and the proportion of output in each industry that goes to employee earnings and, as a result, the number of employees or full-time equivalents (FTEs)[3] associated with each $1 million change in output. I-O analysis provides a straightforward framework as long as the direct effects to the industry are small and certain limiting assumptions about technology are valid (e.g., constant returns to scale, fixed input ratios).

Four types of changes may occur in employment and output, some of which are offset by gains and some of which are not (dead weight losses). These four types of changes, discussed in detail in the sections to follow, include:

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[3]One FTE = 2,080 labor hours = 1 person-year of employment.

- *Type 1 - Compliance Costs*: Direct oil and gas employment losses due to expenditures diverted to compliance.
- *Type 2 - Production Losses*: Production losses at oil and gas operations that install and operate pollution control equipment.
- *Type 3 - First-year Shut-ins*: Employment and output losses at operations that shut in in the first year and do not install pollution control equipment.
- *Type 4 - Delayed Investment*: Employment and output losses resulting from delayed investment (i.e., where the need for pollution control expenditures delays investment in oil and gas exploration and development).

The analysis of these employment and output losses (as well as related impacts) is divided into two parts. Section 7.1 analyzes the national-level impacts of the Coastal Guidelines on both labor and output. Section 7.2 examines the regional impacts associated with employment losses and presents the methodology and results of the employment loss and community-level impact analysis. Note that the net change in employment at the national level includes the regional-level losses (i.e., national and regional losses are not additive).

7.1 NATIONAL-LEVEL OUTPUT AND EMPLOYMENT IMPACTS

7.1.1 Introduction

To comply with the Coastal Guidelines, firms will need to install and operate pollution control systems. The manufacture, installation, and operation of these systems will require labor resources. The labor resources needed to comply with the Coastal Guidelines, however, are very similar to the labor resources that would have been needed if the affected coastal firms had been able to invest in oil and gas production. Specifically, the inputs required for the manufacture, installation, and operation of an injection well are similar to those required for a production well. For example, both an injection well and a production well require tanks, tubular goods, cement, etc. Both require drilling and installation. Both require energy, chemicals, and labor for operation. Therefore, the dollars spent on drilling and operating an injection well would add roughly the same number of employees to the national economy as the dollars spent on drilling and operating a production well. Thus, EPA does not anticipate substantial changes in employment (gains or losses) associated with direct expenditures on pollution control equipment (Type 1 loss as described above) to comply with the Coastal Guidelines.

Despite this balance between losses and gains in employment associated with pollution control expenditures, there are differences in the national-level economy between baseline and postcompliance scenarios. The major differences between baseline and postcompliance labor effects are associated with production losses (described in Chapter Five), which generate Type 2 and Type 3 employment and output losses (production losses from operations that do or do not install and operate pollution control equipment, respectively). Type 2 losses (losses to operations that install and operate pollution control equipment) are dead weight losses (losses in productivity). The losses associated with first-year shut-ins (Type 3 losses) are offset by gains when the money that would have been spent on oil and gas production is reallocated to other productive investments in the general economy. EPA therefore does not count any employment losses from first-year shut-ins in the national-level analysis.[4]

Additionally, the money coastal firms spend on pollution control equipment can be assumed to have been spent on further exploration and development in the absence of the Coastal Guidelines. Although this investment in exploration and development will most likely be delayed rather than never undertaken (since if it is a good investment, it will remain a good investment), some revenue is lost as a result of the investment delay. These output effects will result in net losses in employment (Type 4 losses), which are also dead weight losses.

The following sections present the methodology for determining the impacts associated with the two types of dead weight losses (Types 2 and 4). Section 7.1.1 discusses the methodology for estimating national-level output losses and employment impacts resulting from output losses in the oil and gas industry. Section 7.1.2 presents the results of this analysis.

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[4]However, these losses are considered in the regional analysis (see Section 7.2).

7.1.2 Methodology for Estimating National-Level Output and Employment Impacts

EPA estimates two categories of national-level impacts associated with the Coastal Guidelines: impacts on output in the economy as a whole (in dollars) and impacts on national employment (in FTEs). Both impacts are calculated on the basis of the losses in production and revenue in the oil and gas industry discussed in Chapter Five (Type 2 losses), combined with losses due to delayed investment in further production (Type 4 losses). Losses in production cause losses in oil and gas revenues (output); these output losses, in turn, have effects throughout the economy. For the oil and gas industry, BEA has estimated a national-level multiplier of 1.9420 (RIMS II National Multipliers).[5] This multiplier represents the total dollar change in national output for all industries for each dollar change in oil and gas. Using the BEA multiplier, EPA adjusts oil and gas revenue losses (based on production losses as presented in Chapter Five) to estimate impacts throughout the national economy:

Oil and Gas Industry Revenue Losses (Output) x BEA Multiplier = National Output Losses.

In calculating national-level employment impacts, the Agency uses a similar approach. BEA (RIMS II National Multipliers) has estimated a final-demand multiplier for national-level employment based on oil and gas industry output. This number, 13.0, represents the total change in the number of jobs in all industries nationally for each $1 million change in output delivered to final demand by the oil and gas industry. To determine the results of output losses associated with the production losses calculated in Chapter Five, EPA subtracts losses from first-year shut-ins and annualizes the remaining production losses (in PVBOE) to estimate an average Type 2 production loss per year.[6] Average annual production loss is then converted to an average annual output or revenue loss by multiplying by the price of oil. Since output is equivalent to revenue at the point of final demand, the market value (not the wellhead price) of

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[5]Bureau of Economic Analysis (BEA). U.S. Department of Commerce, 1992. Table A-2.4—Total Multipliers, by Industry Aggregation, for Output, Earnings, and Employment. Regional Input-Output Modeling System (RIMs II), Regional Analysis Division, Washington, D.C.

[6]Present value BOE, rather than total BOE, is used to calculate annualized production losses since EPA uses a constant, real-dollar assumption for the price of oil.

oil is the relevant price to compute the output loss associated with the production loss. EPA has selected \$22/bbl as a reasonable market price for oil.[7] To calculate the output loss to the industry, EPA multiplies the market price of \$22 per bbl by the average annual production loss. This output loss is then divided by \$1 million (since employment losses are per \$1 million dollars of output loss) and multiplied by BEA's employment multiplier.

To determine the losses associated with delayed production (Type 4), EPA assumes that the affected firms will lose revenues because funds equal to the pre-tax compliance costs are diverted from productive to nonproductive investment. EPA assumes that this investment is not permanently lost to the industry as a result of the Coastal Guidelines, but instead is delayed for 5 years.[8] While the investment will be undertaken as long as it is profitable, raising new capital to replace diverted exploration and development capital takes time. The investment delay will result in a present value loss of revenues relative to the baseline.

To quantify the impacts of the investment delay, EPA assumes that the investment would have been made in Year 1 in the baseline and would have provided a pre-tax return of 15 percent[9] of the compliance cost. This number (in dollars), which represents the baseline present value of the return from a productive investment, is then discounted for 5 years at 7 percent to represent a 5-year investment delay. The present value of the investment delay is subtracted from the baseline present value of the investment and the difference is annualized. This estimate will overstate impacts if first-year and baseline shut-ins occur, since compliance costs would not

[7]Recent events have driven the market prices somewhat higher, but \$22 (a midpoint between this year's and last year's price of Louisiana oil) may be a more reasonable estimate for the long term. *The Wall Street Journal* (Thursday, October 8, 1996, p. C21) reports Louisiana Sweet at \$25.68, up from \$17.70 this time last year. The midpoint is \$21.69. Worldwide, current prices range from about \$21/bbl (Arab heavy oil) to \$25/bbl. Additionally, netting out transportation costs, a \$22/bbl price is more consistent with wellhead price in EPA's production loss and firm failure analysis.

[8]EPA believes that a 5-year delay is conservative, given that if an investment is a good one, firms will attempt to undertake it as soon as feasible. Raising new capital actually should take at most a year or two with a viable project already planned.

[9]EPA's use of a 15 percent internal rate of return on the investment (actual return, not projected) is somewhat high (to be conservative) (see Table 3-2 in Chapter Three of this FEIA for typical rates of return).

be incurred by first-year and baseline shut-ins, and these costs are included in EPA's compliance cost estimate.

EPA multiplies this result by the BEA national-level final demand multipliers for output and employment (1.9420 and 13.0, respectively) (RIMS II National Multipliers) to calculate national-level output and employment losses associated with delayed investment.

7.1.3 National-Level Output Reductions and National-Level Employment Impacts

7.1.3.1 Output Losses

Type 2 Output Losses

Table 7-1 shows the total national-level output losses associated with the estimated production losses for Major Pass and Cook Inlet operations discussed in Chapter Five. As the table shows, the average annual production loss is 454,585 BOE.[10] At $22 per bbl (see Section 7.1.2), the associated revenue (output) loss is $10.0 million. Using the output multiplier of 1.9420, national-level output effects are estimated to total $19.4 million per year.

Type 4 Output Losses

Table 7-2 shows the national-level output losses associated with delayed production. The annualized compliance costs for Major Pass and Cook Inlet operations are estimated to be $15.6 million (see Chapter Four of this FEIA). The total present value of these compliance costs is $109.6 million.[11] EPA assumes that this money is no longer immediately available for investment and revenues will be delayed for 5 years. Using the method discussed in Section 7.1.2, where 15 percent of the present value of compliance costs (or $16.4 million) is assumed to

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[10]No first-year shut-in production losses occur.

[11]$15.8 million expended each year for 10 years discounted to the present at 7 percent.

TABLE 7-1

NATIONAL OUTPUT LOSSES ASSOCIATED WITH
POSTCOMPLIANCE PRODUCTION LOSSES
FOR THE CURRENT REGULATORY BASELINE UNDER THE SELECTED OPTIONS
(MAJOR PASS FACILITIES AND COOK INLET PLATFORMS)
(1995 $)

	Annualized production loss (BOE)	Annualized industry output (revenues) lost ($000)	Final-demand output multiplier [a]	Annualized national-level output effects ($000)
Major Pass	301,943	$6,642.7	1.9420	$12,900.2
Cook Inlet	152,642	$3,358.1	1.9420	$6,521.5
Total	454,585	$10,000.9	1.9420	$19,421.7

[a] Represents the total dollar change in output that occurs in all industries for each dollar change in output delivered to final demand by the oil and gas industry.

Sources: Major Pass Dischargers Production Loss Model Runs and Cook Inlet Dischargers Production Loss Model Runs (CBI data; in rulemaking record).
Bureau of Economic Analysis. 1996. Table A-2.4. -- Total Multipliers, by Industry Aggregation, for Output, Earnings, and Employment. Regional Input-Output Modeling System (RIMS II), Regional Economic Analysis Division.

TABLE 7-2

NATIONAL OUTPUT LOSSES ASSOCIATED WITH
DELAYED PRODUCTION FOR THE CURRENT
REGULATORY BASELINE UNDER THE SELECTED OPTIONS
(MAJOR PASS FACILITIES AND COOK INLET PLATFORMS)
(1995 $)

	Annualized industry output (revenues) lost ($000)	Final-demand output multiplier [a]	Annualized national-level output effects ($000)
Major Pass	$565.0	1.9420	$1,097.2
Cook Inlet	$106.9	1.9420	$207.6
Total	$671.9	1.9420	$1,304.8

[a] Represents the total dollar change in output that occurs in all industries for each dollar change in output delivered to final demand by the oil and gas industry.

Sources: Major Pass Dischargers Production Loss Model Runs and Cook Inlet Dischargers Model Runs (CBI data; in rulemaking record).
Bureau of Economic Analysis. 1996. Table A-2.4. -- Total Multipliers, by Industry Aggregation, for Output, Earnings, and Employment. Regional Input-Output Modeling System (RIMS II), Regional Economic Analysis Division.

be the return associated with this investment, the delayed investment will result in a present value loss of $4.7 million.[12] This investment delay will result in a reduction in annualized returns of $0.7 million. Multiplying these output numbers by the national output multiplier for the oil and gas industry gives a loss of $1.3 million per year resulting from the investment delay.

7.1.3.2 Employment Losses

Type 2 Employment Losses

Table 7-3 presents the national-level employment losses associated with the lost oil and gas industry output estimated above. EPA converts the industry revenue losses into millions of 1992 dollars[13] and multiplies these losses by the employment multipliers to determine total employment losses of 119 FTEs.

Type 4 Employment Losses

Table 7-4 presents the national-level reduction in employment associated with the output losses estimated above. EPA converts the returns forgone due to delayed investment into millions of 1992 dollars and multiplies these numbers by the employment multipliers to determine the total reduction in employment of 8 FTEs.

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[12]$16.6 million is multiplied by $1/1.07^5$ to discount this return to Year 1 from Year 5. This equals $11.9 million. The loss is calculated as: $16.6 million - $11.9 million = $4.8 million.

[13]BEA's RIMS II national multipliers are based on 1992 data.

TABLE 7-3

NATIONAL EMPLOYMENT LOSSES
ASSOCIATED WITH LOST OUTPUT (TYPE 2 LOSSES) FOR THE
CURRENT REGULATORY BASELINE UNDER THE SELECED OPTIONS
(MAJOR PASS FACILITIES AND COOK INLET PLATFORMS)

	Annualized industry-level output effects ($000 1995)	Annualized industry-level output effects ($000 1992) [a]	Final-demand employment multiplier [b]	Total annual employment losses (FTEs)
Major Pass	$6,642.7	$6,052.7	13.0	79
Cook Inlet	$3,358.1	$3,059.8	13.0	40
Total	$10,000.9	$9,112.5	13.0	119

[a] Output values deflated from 1995 dollars to 1992 dollars because the Bureau of Economic Analysis employment multipliers are based on 1992 data.
[b] Represents the total change in number of jobs that occurs in all industries for each $1 million change in output delivered to final demand by the oil and gas industry.

Sources: Table 7-1 in this FEIA.
Bureau of Economic Analysis. 1996. Table A-2.4. -- Total Multipliers, by Industry Aggregation, for Output, Earnings, and Employment. Regional Input-Output Modeling System (RIMS II), Regional Economic Analysis Division.

TABLE 7-4

NATIONAL EMPLOYMENT LOSSES
ASSOCIATED WITH DELAYED PRODUCTION (TYPE 4 LOSSES) FOR THE
CURRENT REGULATORY BASELINE UNDER THE SELECTED OPTIONS
(MAJOR PASS FACILITIES AND COOK INLET PLATFORMS)

	Annualized industry-level output effects ($000 1995)	Annualized industry-level output effects ($000 1992) [a]	Final-demand employment multiplier [b]	Total annual employment losses (FTEs)
Major Pass	$565.0	$514.8	13.0	7
Cook Inlet	$106.9	$97.4	13.0	1
Total	$671.9	$612.2	13.0	8

[a] Output values deflated from 1995 dollars to 1992 dollars because the Bureau of Economic Analysis employment multipliers are based on 1992 data.
[b] Represents the total change in number of jobs that occurs in all industries for each $1 million change in output delivered to final demand by the oil and gas industry.

Sources: Table 7-2 in this FEIA.
Bureau of Economic Analysis. 1996. Table A-2.4. -- Total Multipliers, by Industry Aggregation, for Output, Earnings, and Employment. Regional Input-Output Modeling System (RIMS II), Regional Economic Analysis Division.

7.1.3.3 Total Type 2 and Type 4 Output and Employment Losses

Total Output Losses

Given the $10.0 million of lost oil and gas industry output leading to $19.4 million in national-level support losses and the $0.7 of foregone oil and gas industry output per year leading to $1.3 million in national-level output losses, total output effects (based both on lost and delayed production) are estimated to be $20.7 million per year. This reduction in output is 0.0003 percent of gross domestic product (GDP) of $7.2 trillion[14] and 0.03 percent of oil and gas industry's contribution to GDP in 1995[15] (see Table 7-5 for a summary of output losses).

Total Employment Losses

Combining the employment losses and foregone employment, EPA estimates a total reduction of 127 FTEs as a result of the Coastal Guidelines. This lost or foregone employment is only 0.0001 percent of total 1995 U.S. employment of 124.9 million persons (see Table 7-5 for a summary of employment losses).[16]

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[14]Economic Report of the President, February 1996, U.S. Government Printing Office, Washington, D.C.

[15]Estimated at $70.0 billion in 1995, based on the estimate that the oil and gas industry contributes approximately 1 percent to total GDP. Percent contribution estimated using 1992 data, cited in Table Nos. 700 and 1173, Statistical Abstract of the U.S. Department of Commerce, U.S. Bureau of the Census, September 1995.

[16]Bureau of Labor Statistics, Personal communication with Anne Jones, ERG, dated July 24, 1996, regarding total U.S. employment.

TABLE 7-5

SUMMARY OF NATIONAL EMPLOYMENT AND OUTPUT LOSSES FOR THE CURRENT REGULATORY BASELINE UNDER THE SELECTED OPTIONS

(MAJOR PASS FACILITIES AND COOK INLET PLATFORMS)

(1995 $)

	Annualized production losses (BOE)	Annualized industry output (revenue) losses ($000)	Annualized national-level output losses ($000)	Annual Reduction in FTEs
Type 1 Losses [a]	--	--	--	--
Type 2 Losses	454,585	$10,000.9	$19,421.7	119
Type 3 Losses [a]	--	--	--	--
Type 4 Losses [b]	--	$671.9	$1,304.8	8
Total Losses	454,585	$10,672.8	$20,726.5	127

[a] Type 1 and Type 3 losses are not calculated in this FEIA because any losses and gains are assumed to offset each other on the national level.

[b] Type 4 production losses are not calculated.

Sources: Tables 7-1, 7-2, 7-3, and 7-4 in this FEIA.

7.2 REGIONAL EMPLOYMENT IMPACTS

7.2.1 Introduction

As noted above, compliance costs by themselves do not really have a national-level impact because the money is not lost; it is simply reallocated. In fact, it is even reallocated to many of the same inputs, so the capital-to-labor ratio of the reallocated investment does not change substantially between baseline and postcompliance scenarios.[17] First-year shut-ins and firm failures (Type 3 losses), production losses from earlier shut-ins (Type 2 losses), and losses from delayed investment (Type 4 losses) are used to determine the potential dislocation effects of the Coastal Guidelines at the regional level.

The methodology for calculating Type 2 and Type 4 losses at the regional level is similar to that used to compute national-level losses. Production (revenue) losses are used to estimate regional employment losses in the same way as at the national level, but using regional, rather than national, level multipliers to determine average annual primary and secondary losses in employment. These losses encompass all losses that will occur sometime over the course of the analytical time frame (but not in the first year). Losses associated with delays in investment are an issue at the national level, but less so at the regional level, since the delayed investment may not have occurred in the region of interest. To be conservative, EPA has assumed that productive capital would have stayed in the region, and so estimates Type 4 losses also.

The major difference in calculating employment losses at the regional level vs. at the national level (other than the use of regional-level rather than a national-level multiplier) is that losses due to first-year shut-ins (Type 3 losses) are counted at the regional level, whereas at the national level, these losses are balanced by gains when investments are reallocated to other regions or economic sectors. To calculate Type 3 losses, EPA uses the primary direct losses occurring only in the portion of the coastal oil and gas industry discharging produced water as of the effective date of the rule (i.e., Major Pass and Cook Inlet dischargers; Chapter Ten discusses

[17]If the capital-to-labor ratio is much smaller in one industry and larger in another, when money is reallocated from one to another industry, employment can change.

impacts under an alternative baseline scenario).[18] As discussed above, secondary (indirect and induced) impacts must also be estimated. These losses include employment losses in industries providing inputs to the coastal oil and gas industry (as well as other supporting industries, such as community-based services) that lose income when layoffs occur; such losses would result from any significant decline in demand for inputs, as well as from regional reductions in personal income. To compute total primary plus secondary losses, EPA uses another type of multiplier, a regional direct-effect multiplier. EPA multiplies the direct losses from shut-ins and firm failures by the appropriate regional direct-effect multiplier. These losses are the immediate impact (Type 3 losses) on community employment levels resulting from implementation of the Coastal Guidelines.

7.2.2 Methodology

The following sections present the methodology for computing Type 3 losses, then summarize the approach for estimating Type 2 and Type 4 losses on a regional level.

7.2.2.1 Type 3 Primary Employment Losses

Primary employment losses for the regional impact analysis include employee layoffs associated with the first-year facility/platform shut-ins estimated in the production loss analysis and the firm failures in the firm-level analyses. These job losses (measured in hours) are estimated using survey data regarding annual employment hours.

To estimate total primary employment losses, EPA first calculates losses from first-year facility/platform shut-ins. Based on the Section 308 Survey, the Agency estimates that 1.16 full-time equivalents (FTEs) are required to operate each coastal oil and gas well in the Gulf of Mexico (4,675 Gulf of Mexico wells divided by 5,403 Gulf of Mexico employees reported in the

[18]EPA recognizes that the rule only becomes "real" when it is implemented through issuance of an NPDES permit to discharge. For purposes of analysis here, EPA assumes immediate implementation.

Section 308 Survey—see Chapter Seven of the PEIA). This estimate may be high because some operators might have reported secondary employment (e.g., well service portions of their business, or drilling), not just oil and gas production employment, in their financial data. Such over-reporting is assumed to be offset, however, by the fact that some firms hire outside contractors to run their operations and thus report very few operating employees.

For Cook Inlet, EPA uses the same methodology as for the Gulf to estimate employment per well, i.e., EPA divides numbers of employees reported in the Section 308 Survey by numbers of wells (431 employees and 224 wells[19] = 1.9 employees per well). First-year facility or platform shut-ins are assumed to be associated with the direct loss of this number of employees per well in each region summed over all first-year shut-ins.

However, in general, these first-year shut-ins only have a few additional years of economic life in the baseline. EPA assumes that the true impact is the difference between a loss now and a loss in the future (i.e., the year when the facility or platform would have shut in in the baseline). Thus the number of FTEs lost (which can be thought of as "earnings" lost) a number of years later (as determined based on the relevant model runs) is discounted to create a loss in a present value sense, and then subtracted from the first-year losses. These differences are then annualized. The difference in employment can be attributed to the Coastal Guidelines.

To calculate employment losses from firm failures, EPA analyzes firms to determine whether they are likely to fail under the various regulatory options. If a firm is shown to be likely to fail, it is assumed that some firm-level employment is lost. Facilities/platforms (owned by failing firms) that do not shut in as a result of the Coastal Guidelines are assumed to be sold intact with no loss of employment when their operator fails.[20] Thus, no additional employment

[19]See Chapter Three of this FEIA.

[20]This assumption follows from assuming a fixed level of productivity (producing wells per employee). Given that the wells in question are shown to be productive and assuming that a fixed number of employees are needed to operate them, any losses in employment are expected to be temporary because firms acquiring new wells would most likely need to expand their employment. The costs associated with dislocations and relocations should be limited, given that the wells remain in the same geographic area and operating personnel would most likely be hired locally. This is true both in the Gulf of Mexico and Cook Inlet.

losses are associated with firm failure beyond administrative and other nonproduction personnel (production personnel losses are accounted for in the production loss side of the analysis). It is difficult to estimate the proportion of nonproduction employment that might be affected; other areas of business that could be sold intact rather than liquidated are not surveyed in sufficient detail. At maximum, however, all nonproduction employment can be assumed to be lost with a firm failure (for firms included in the Section 308 Survey, the 1992 nonproduction employment is known). EPA expresses total employee hours lost in FTEs, assuming that 2,080 hours (52 weeks/year x 40 hours/week) equals 1 FTE.

7.2.2.2 Type 2, Type 3, and Type 4 Secondary Employment Losses

As discussed above, secondary employment losses occur in industries providing inputs to the coastal oil and gas industry as a result of reduced expenditures for these inputs. The discussion below focuses first on the effects of the first-year shut-ins and firm failures, and then addresses the impacts derived using the effects of production losses.

To estimate Type 3 secondary employment losses using the first-year shut-ins and firm failure employment effects, EPA uses BEA's regional (state-level) direct-effect multipliers, instead of the national final-demand multipliers discussed above (which are used to compute changes in employment based on changes in output). Direct-effect multipliers represent the total change in the number of FTEs in all industries in a region for each FTE lost or gained in the oil and gas industry. In this regional analysis, since the number of employees (FTEs) lost in the region is known (i.e., employment losses do not have to be estimated based on output), the direct-effect multipliers are the appropriate multipliers to use. These multipliers will somewhat overstate the effects in the immediate regions near the affected operations in Louisiana and Alaska, however, because they reflect statewide changes in employment.

In this analysis, the industry directly affected is the Crude Petroleum and Natural Gas Industry (SIC 131).[21] The regional (state) multiplier (measuring direct, indirect, and induced employment effects) reported by BEA (RIMS II Handbook) for this industry is 2.6985 for Louisiana and 2.7792 for Alaska. The total number of job losses, both primary and secondary, is computed by multiplying the primary losses in coastal oil and gas industry jobs (measured in FTEs) by the relevant multiplier:

Total direct and indirect job losses in the Gulf coastal region = 2.6985 * primary losses in the Gulf coastal oil and gas industry.

Total direct and indirect job losses in the Cook Inlet region = 2.7792 * primary losses in the Alaska coastal oil and gas industry.

EPA also estimates impacts on employment calculated from production losses (Type 2 losses) to provide a sense of the impacts on the local economy over the full time frame of the analysis, not just in the first year. Note that these impacts, however, represent less of an immediate dislocation effect, since the more warning employees have that their jobs will be lost, the better the employees can plan to minimize any dislocation effects.[22] To calculate the regional employment losses associated with production losses, EPA uses the state final-demand employment multipliers of 8.6 FTEs per $1 million change in output for Louisiana and 4.0 jobs per $1 million change in output for Alaska (RIMS II Handbook). As in the national-level analysis, EPA multiplies the present value production losses by the market value of that production ($22/bbl) to estimate the output loss in the oil and gas industry. EPA subtracts production losses due to first-year shut-ins from total production losses since the losses in employment for first-year shut-ins are calculated already, as discussed above. EPA then multiplies the output change (adjusted to 1989 dollars) for each region by the appropriate multiplier to estimate the total number of primary and secondary job losses that will occur annually over the time frame of the analysis.

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[21]Multipliers based on direct employment changes are available at an aggregated industry level only.

[22]In many cases, the Coastal Guidelines result in a loss of a year or two of production, e.g., in baseline the operation will produce until Year 10, while postcompliance the operation will produce until Year 9.

7.2.2.3 Measuring Impacts at the Community Level

The significance of employment losses for the affected community as a whole is estimated in terms of their impact on the community's overall level of employment. Data necessary to determine the impacts on the community include the community's total labor force and employment rate. For purposes of the analysis in Louisiana, the community is defined as the parishes near the affected facilities. For the Major Pass dischargers, EPA assumes employment losses occur primarily in or around several coastal parishes in Louisiana (Plaquemines, St. Bernard, Jefferson, and Orleans, which contain or are contiguous to the Mississippi Delta and its Major Passes). Other parishes might also be affected, but are considered less likely. According to Bureau of Labor Statistics for 1991 (BLS data),[23] an estimated 465,406 employed persons live in these four parishes. The unemployment rates over all four parishes range from 5.6 to 7.0 percent, with a weighted average for the four-parish region of 5.9 percent. In Alaska, community employment information is taken from the Kenai region of Alaska (Kenai Peninsula Borough), where 16,882 employed persons live and where the unemployment rate was 12.7 percent in 1991.

7.2.3 Results—Regional Employment Impacts From BAT Options

7.2.3.1 Baseline Losses: Primary and Secondary Employment Losses

As discussed above, employment losses are counted when a facility or platform shuts in (100 percent of the per-well employment) and when a firm fails (100 percent of nonproduction employment).

Under the current regulatory baseline, no Major Pass operations are expected to shut in, nor are any firms expected to fail. Thus no baseline direct employment losses are estimated for this group. Total coastal employment in the Major Pass discharger group is estimated at a

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[23]BLS data obtained at http://www.census.gov/datamap/www/index.html. The most recent year for which parish-level BLS data are available is 1991. Weighted average calculated by EPA on the bans of population.

minimum of 406 production FTEs (most firms did not report employment or break out coastal employment).

Total current Cook Inlet direct oil and gas production employment is estimated to be 431 FTEs (Section 308 Survey Questionnaire). No employment is expected to be lost under the current regulatory baseline (i.e., no firms are expected to fail and no production is expected to be lost in baseline). Among the Major Pass and Cook Inlet operations combined, total baseline employment is at least 837 FTEs.

7.2.3.2 Postcompliance Losses: Primary and Secondary Employment Losses

EPA's selected options for the Coastal Guidelines are Option #2 for produced water/TWC (zero discharge all; discharge limitations for Cook Inlet) and Option #1 for drilling wastes (which corresponds to current practice and thus is a no-cost option). No direct losses of employment occur under Option #2 for produced water/TWC and Option #1 for drilling wastes, since no firm failures or first-year shut-ins occur (see Chapters Five and Six of this FEIA). Thus EPA expects no direct, first-year employment impacts due to the Coastal Guidelines.

However, for the selected options, employment losses associated with production losses (Type 2 losses) will occur over time. Total production losses in Louisiana (among the Major Pass dischargers) amount to 2.1 million PVBOE (see Table 5-5 in Chapter Five of this FEIA), or 301,943 BOE annually (these losses do not need to be adjusted for first-year shut-ins, since none occur). The value of this output is $5.6 million in 1989 dollars (using $22/bbl of oil and a deflator of 0.8435),[24] thus EPA calculates the annual reduction in the number of FTEs related to production losses to be 48 FTEs in Louisiana as a result of the Coastal Guidelines, based on 8.6 FTEs lost per $1 million output loss.

Production losses in Cook Inlet, Alaska, under the selected options total 1.1 million PVBOE (see Table 5-4 in Chapter Five of this FEIA), or 152,642 BOE annually (these losses

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[24]Engineering News Record Construction Cost Index is used to deflate from 1995 to 1989.

also do not need to be adjusted for first-year shut-ins). The value of this output is $2.8 million in 1989 dollars. Thus the total number of FTEs lost annually in Alaska as a result of the Coastal Guidelines is estimated to be 11, based on 4.0 FTEs lost per $1 million output loss.

Employment losses due to delayed investment among the Major Pass dischargers is estimated to be 4 FTEs, based on an annual output loss of $0.5 million in 1989 dollars (see Table 7-4) and given the 8.6 FTEs lost per $1 million change in output.

Employment losses due to delayed investment among the Cook Inlet dischargers is estimated to be 1 FTE, based on an annual output loss of $0.1 million in 1989 dollars (see Table 7-4) and given the 4.0 FTEs lost per $1 million change in output.

Based on losses due to first-year shut-ins and firm failures (no losses) and production losses and delayed investment under the selected options, jobs estimated to be lost annually in Louisiana and Alaska as a result of the Coastal Guidelines total 5 FTEs (see Table 7-6 for a summary of these impacts).

Employment losses combined for Type 2, Type 3, and Type 4 losses are 52 FTEs in Louisiana and 12 FTEs in Cook Inlet, for a total of 64 FTEs under the current regulatory baseline.

7.2.3.3 Community-Level Impacts

Selected Options

EPA anticipates no immediate direct, indirect, and induced employment losses associated with first-year shut-ins and firm failures under the selected options, so no immediate community-level impacts are anticipated. Based on employment losses calculated using production losses, EPA estimates that 48 employees in Louisiana and 11 employees in Alaska might be lost in the community per year on average over the timeframe of the analysis. Added to this are the 4 FTEs lost in Louisiana and 1 FTE lost in Alaska due to delayed investment. This estimate

TABLE 7-6

SUMMARY OF REGIONAL EMPLOYMENT AND OUTPUT LOSSES FOR THE CURRENT REGULATORY BASELINE UNDER THE SELECTED OPTIONS

(MAJOR PASS FACILITIES AND COOK INLET PLATFORMS)

	Annualized production losses (BOE)	Annualized industry output (revenue) losses ($000 1995)	Annualized industry output (revenue) losses ($000 1989) [c]	Annual Reduction in FTEs
Type 1 Losses [a]	--	--	--	--
Type 2 Losses	454,585	$10,000.9	$8,436.1	59
Type 3 Losses	--	--	--	0
Type 4 Losses [b]	--	$671.9	$566.8	5
Total Losses	454,585	$10,672.8	$9,002.9	64

[a] Type 1 losses are not calculated in this FEIA because any losses and gains are assumed to offset each other on the national level.
[b] Type 4 production losses are not calculated.
[c] Output values deflated from 1995 dollars to 1989 dollars because the Bureau of Economic Analysis regional employment multipliers use 1989 dollars.

Sources: EPA analysis described in text; Tables 7-1, 7-2, 7-3, and 7-4 in this FEIA.

TABLE 7-7

SUMMARY OF REGIONAL EMPLOYMENT AND AND OUTPUT LOSSES FOR THE COOK INLET PLATFORMS UNDER THE OPTION #3 FOR PRODUCED WATER (ZERO DISCHARGE)

	Annualized production losses (BOE)	Annualized industry output (revenue) losses ($000 1995)	Annualized industry output (revenue) losses ($000 1989) [c]	Annual Reduction in FTEs
Type 1 Losses [a]	--	--	--	--
Type 2 Losses	1,347,801	$29,651.6	$25,012.3	100
Type 3 Losses	--	--	--	3
Type 4 Losses [b]	--	$1,627.2	$1,372.6	5
Total Losses	1,347,801	$31,278.8	$26,384.9	108

[a] Type 1 losses are not calculated in this FEIA because any losses and gains are assumed to offset each other on the national level.
[b] Type 4 production losses are not calculated.
[c] Output values deflated from 1995 dollars to 1989 dollars because the Bureau of Economic Analysis regional employment multipliers use 1989 dollars.

Source: EPA analysis described in text.

overstates community losses, since the multipliers used to develop these estimates project losses in employment over the entire state, not just in the parishes and boroughs of concern.

Using the employment losses projected in Louisiana and the current employment in the four parishes in Louisiana expected to bear the greatest impact (465,406 employed persons), EPA estimates that these losses represent a 0.01 percent change in employment in the affected areas of Louisiana (unemployment rate changes from 5.9 percent to 5.91 percent).

For Kenai Peninsula Borough, Alaska (with employment of 16,882 persons), EPA estimates that the employment losses in the affected area of Alaska lead to a change of 0.05 percent in the unemployment rate in this area (the unemployment rate increases from 12.7 percent to 12.76 percent). EPA concludes that employment impacts of the Coastal Guidelines for the four parishes in Louisiana or for the Kenai Peninsula, Alaska, are not significant.

Option #3 (Zero Discharge All)

Employment Losses Under Option #3 in Cook Inlet—Under Option #3 for produced water/TWC wastes (zero discharge all), which is not EPA's selected option, employment losses totaling 25 FTEs (based on one platform with 13 wells in Cook Inlet[25] shutting in the first year—see Chapter Five of this FEIA) are expected to occur. When the discounted value of those FTEs lost 6 years from now when the platform shuts in in baseline is subtracted from the loses in the first year, 8 FTEs are estimated to be lost as a result of the Coastal Guidelines. When this loss is annualized, EPA estimates that 1 FTE will be lost annually. No firm-level employment losses are expected to occur. Total direct primary and secondary Type 3 losses (using the direct effect multiplier of 2.7792 for Alaska) are estimated to be 3 FTEs based on firm failures and first-year shut-ins.

Production losses in Cook Inlet, Alaska, under Option #3 for produced water total 9.5 million PVBOE (see Table 5-4 in Chapter Five of this FEIA), or 1.3 million BOE annually. The

[25]Major Pass results do not change under this option so are not discussed in this subsection.

value of this output is $25.1 million in 1989 dollars. Thus the total number of FTEs lost annually in Alaska as a result of the Coastal Guidelines is estimated to be 100, based on 4.0 FTEs lost per $1 million loss of output.

Employment losses due to delayed investment among the Cook Inlet dischargers is estimated to be 5 FTEs, based on an annual output loss of $1.4 million in 1989 dollars (see Table 7-7) and given the 4.0 FTEs lost per $1 million change in output.

The total annual job loss in Alaska as a result of the Coastal Guidelines due to first-year shut-ins and firm failures, production losses, and delayed investment under Option #3 for produced water is estimated to be 108 FTEs (see Table 7-7 for a summary of Option #3 impacts).[26]

Community-Level Impacts Under Option #3 in Cook Inlet—EPA estimates that the losses of employment (108 FTEs annually) in the affected area of Alaska under produced water Option #3[27] would increase the unemployment rate by 0.6 percent in this area (employment rate changes from 12.7 percent to 13.3 percent). EPA concludes that the impact to Kenai Peninsula Borough is significant under this option. The Kenai is disproportionately dependent on oil and gas production. In the borough, the oil and gas industry accounts for 6.3 percent of total payroll and makes up 12.3 percent of the total labor force (BLS data). Because of the borough's high unemployment rate and sensitivity to employment impacts on the local oil and gas industry, EPA concludes that employment impacts (along with results of analyses in Chapter Five) contribute to a finding of economic inachievability for zero discharge of produced water in Cook Inlet.

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[26]These losses would be further compounded if EPA had selected zero discharge requirements for drilling waste. Additional platforms shut in under this scenario and substantially more production is lost (see Chapter Five).

[27]Impacts in Major Pass communities do not change from Option #2 results under Option #3.

CHAPTER EIGHT

IMPACTS ON THE BALANCE OF TRADE, INFLATION, AND CONSUMERS

Although the costs and economic impacts of the BAT and NSPS regulations will fall primarily on the coastal oil and gas industry, including its employees, other secondary effects in other sectors of the economy will also occur. Chapter Seven discusses secondary employment effects, and Chapter Five discusses impacts on federal and state tax revenues. This section reviews the potential effects of regulatory costs on the balance of trade and on inflation and consumers.

8.1 IMPACTS ON THE BALANCE OF TRADE

The United States has now reached a point where oil imports exceed total oil production. *Oil and Gas Journal* reports that "for the first time in history, more than half the oil used in the United States in a given year [1994] was imported."[1] A shortage of trained personnel and workover rigs are factors cited as limiting any near-term sizable increase in domestic production.[2,3,4] Indications are that unless domestic demand for oil is curbed, the United States will continue to import a growing percentage of the supply needed to satisfy domestic consumption. In 1995, U.S. domestic production of crude oil was approximately 47 percent of

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[1]"OGJ Newsletter," Oil and Gas Journal (OGJ), Vol. 93, No. 4, January 23, 1995, p. 2.

[2]"Despite Output Push, U.S. Probably Cannot Avoid Oil Production Decline in 1991," Oil and Gas Journal (OGJ), September 17, 1990, pp. 21-24.

[3]"W. Coast Best Potential for Output Hike Soon," Oil and Gas Journal (OGJ), October 1, 1990, pp. 38-42.

[4]"U.S. Oil Flow Hike Unlikely Outside W. Coast," Oil and Gas Journal (OGJ), October 1, 1990, pp. 32-36.

total U.S. demand (production plus imports).[5] This phenomenon is occurring independent of any incremental pollution control costs.

EPA estimated the potential lifetime total production loss of 5.8 million BOE in Chapter Five. Under the selected options, annual production declines of 0.4 million BOE equal 0.02 percent of U.S. domestic crude oil production (over 2 billion barrels in 1995).[6] Furthermore, the lifetime losses are only 0.2 percent of total coastal production (not including California and the North Slope) over the lifetimes of the affected discharging wells and platforms (see Chapter Five). This is a relatively small percentage given the estimated annual decline in domestic production of about 3 percent *per year* cited in projections.[7] Thus the change in the balance of trade expected from the rulemaking will not be significant compared to changes caused by other factors.

8.2 IMPACTS ON INFLATION AND CONSUMERS

The regulations will lead to higher costs for industry operators. When evaluating the possibility of this effect on typical companies, EPA did not assume that companies could raise prices to recover these costs. This assumption would be consistent with the fact that the United States is a price-taker in the world oil market (i.e., the price the companies will receive for their product is determined by the world oil price and not domestic costs). Given the nation's continued growth in demand, supply (and therefore price) is not likely to be controlled domestically (although control by OPEC is still possible). The fact that coastal production is such a small fraction of total U.S. production further reduces any potential to affect prices. Given the inability of the companies to raise prices in response to increased costs, no substantial impacts on inflation are likely to result from increased costs associated with pollution controls on

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[5]U.S. Department of Energy (DOE). 1996. "Crude Oil Supply and Disposition, 1973—Present." Obtained at http://www.eia.doe.gov.

[6]Ibid.

[7]"OPEC, Once All-Powerful, Faces a Cloudy Tomorrow," Drewry Shipping Consultants, Oil and Gas Journal (OGJ), August 22, 1994, p. 18 (Table).

coastal oil and gas effluents. Therefore, the effects of this rulemaking will fall exclusively on coastal oil and gas producers and their employees and shareholders. Consumers of oil and gas products will not be facing higher prices as a result of higher coastal production costs.

CHAPTER NINE

IMPACTS ON NEW SOURCES

EPA has set the selected NSPS and PSNS regulations equal to the selected BAT options for all waste streams with new source requirements. Because new sources will face the same requirements as existing sources, most of whom are achieving zero discharge, new operations should face no significant barriers to entry. Furthermore, since EPA has found that BAT requirements are economically achievable, NSPS requirements should be economically achievable as well.

To further confirm that NSPS requirements both are economically achievable and create no barriers to entry, EPA looked more closely at how the NSPS requirement for produced water/TWC might affect a project in Cook Inlet.[1] The NSPS requirement for produced water will require a new platform to meet standards equivalent to those achieved by improved gas flotation (Option #2 for existing platforms). To perform its analysis, EPA used the Steelhead platform as a model for a possible future Cook Inlet project. Steelhead was selected as the model because it is the platform most recently constructed in the Inlet (in the mid-1980s). Data for Steelhead from the PEIA were supplemented with updated data and parameters from a model for a Cook Inlet NSPS platform developed in the EIA for the offshore oil and gas industry ("Offshore EIA").[2]

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[1]The Region 6 General Permits for produced water and drilling wastes already require zero discharge in the coastal Gulf of Mexico area, so only the Coastal Guidelines covering TWC wastes will have an incremental regulatory impact in that region under NSPS requirements. Incremental TWC losses, moreover, amount to less than $2,000 per well annually. Additionally, under NSPS requirements, a new platform in Cook Inlet will need to meet the same toxicity limits on drilling wastes currently being met by other operations in Cook Inlet. NSPS limits on drilling wastes, therefore, are no more stringent than baseline assumptions for an existing Cook Inlet platform and, as such, are not associated with any incremental costs.

[2]U.S. EPA. 1993. Economic Impact Analysis of Effluent Guidelines and Standards of Performance for the Offshore Oil and Gas Industry. Washington, D.C. January.

EPA has estimated capital costs for constructing and installing dedicated wells for produced water injection (zero discharge) for a new platform in Cook Inlet to be $8.1 million (see EPA's Develoment Document),[3] which is only 2.3 percent of the estimated present value costs for the construction of an entire NSPS platform (approximately $357 million in 1995 dollars for leasebid, platform construction, and drilling of exploratory, development, and production wells, based on data from Steelhead [see Chapter Five] and the Offshore EIA). The costs of purchasing and installing gas flotation equipment, moreover, are generally much less than the capital costs incurred in meeting a zero discharge requirement. The highest capital cost for retrofitting an existing Cook Inlet platform for gas flotation (excluding platform modification costs), for example, is estimated at $1.7 million.[4] This amount is equal to 0.05 percent of the construction cost of a platform like Steelhead. Thus, given the selected NSPS produced water option of gas flotation, capital costs of compliance are very small (less than 2.3 percent, in the worst case), relative to the capital expenditures required for the project as a whole.

The addition of up to 2.3 percent (under zero discharge) to the overall costs of constructing a platform in Cook Inlet should not present a barrier to entry, even if no other platforms in Cook Inlet are required to meet BAT requirements. Additionally, since BAT modeling shows that it is economically achievable (with minimal impacts) for existing platforms to meet discharge limits based on improved gas flotation, it should be economically achievable for new platforms to meet the same limits. All new and existing offshore platforms must meet similar limits, so a new Cook Inlet platform also is no more disadvantaged than any new offshore platform.

Despite the economic achievability of the selected NSPS regulations, however, it does not appear likely that an NSPS project will be undertaken in Cook Inlet in the near future. EPA's baseline model, in fact, suggests that a new platform will not be built in Cook Inlet in the next 15

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[3]McIntyre, Jamie, Avanti, Memorandum to Ron Jordan, U.S. EPA, dated May 30, 1996, entitled "NSPS Compliance Costs for Drilling Wastes and Produced Water Management in Cook Inlet."

[4]Avanti. 1996. Costs and Loadings for Effluent Limitations Guidelines for the Coastal Subcategory of the Oil and Gas Extraction Industry. Prepared for the U.S. Environmental Protection Agency. April 29.

years without substantial changes in oil price, peak production rates per well, or other related factors.[5] In creating this model, EPA assumed that the NSPS operator would be a major, integrated producer. Costs (inflated to 1995 dollars from the Offshore EIA) to develop the model platform include: $71,000 for leasebid, $12.9 million for drilling of each exploratory or delineation well (with a discovery efficiency of 0.27), $254.8 million for platform construction and drilling, and $4.7 million drilling costs per production well. The platform is initially assumed to service 34 wells, with an additional 7 wells added after 10 years of production.[6] As noted above, the present value of all capital costs associated with such an NSPS project is estimated to be $357.0 million. Other inputs in the NSPS model, including wellhead prices, production levels, operating costs, decline rate, and tax and royalty rates are based on the common parameters and Steelhead-specific inputs used in the Cook Inlet/Major Pass production loss model (see Chapter Five).

For an NSPS project to be viewed as a good investment, it must have an estimated internal rate of return greater than the 20 to 25 percent "hurdle rate" generally associated with oil and gas projects (Offshore EIA). A potential investment with an internal rate of return less than the hurdle rate does not offer revenues high enough to offset the costs and risks associated with that investment.

EPA's baseline analysis of the model NSPS project indicates that a new project would have to have much higher production earnings (i.e., much lower costs, or much higher prices combined with much higher initial production) than the typical existing Cook Inlet project before the internal rate of return would be high enough to justify such an investment. EPA confirmed these conclusions by conducting sensitivity analysis on the wellhead prices, operating costs, and peak production rates associated with the platform. Prices had to be 50 percent higher and all wells drilled had to be assumed to be productive (i.e., a 100 percent success rate) at the peak

[5]NSPS Production Loss Model Runs. (CBI data; in rulemaking record.)

[6]NSPS Model Input Parameters and Assumptions. (CBI data; in rulemaking record.)

production rates currently reported for new wells in Cook Inlet before the project's internal rate of return even approached a figure that would attract the interest of an investor.[7]

Thus, EPA believes a new platform is unlikely to be built in Cook Inlet at this time without, for example, substantial increases in the price of oil and the discovery of a major new field capable of producing initially at rates greater than the peak production rates currently experienced in the Inlet. This finding is substantiated by industry contacts who have indicated that no new platforms are likely to be constructed in Cook Inlet in the foreseeable future (see Chapter Three of this FEIA).

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[7]NSPS Production Loss Model Runs. (CBI data; in rulemaking record).

CHAPTER TEN

ALTERNATIVE BASELINE SCENARIO

10.1 INTRODUCTION AND PROFILE OF AFFECTED OPERATIONS UNDER THE ALTERNATIVE BASELINE SCENARIO

The preceding chapters of this FEIA present the impacts of the Coastal Guidelines under the current regulatory baseline. In response to concerns raised in comments on the proposal, this chapter considers two additional groups of dischargers and assesses all impacts on the basis of an alternative regulatory baseline in which these groups, in addition to Major Pass and Cook Inlet dischargers, are assumed to be affected by the Coastal Guidelines. The two groups are referred to here as the Louisiana Open Bay and Texas Individual Permit applicant dischargers. To analyze impacts on the alternative baseline, EPA assumes that the dischargers in these groups, in the absence of the Coastal Guidelines, will apply for and receive individual permits allowing them to continue to discharge produced water despite the Louisiana state law prohibiting produced water discharge to open bays beyond January 1997 and despite the Region 6 General Permits currently applicable to these facilities. Analysis based on this assumption provides an estimate of the broadest possible impact of the Coastal Guidelines, although the assumption that these entities would be allowed to discharge in the absence of the Coastal Guidelines is not necessarily realistic, and does not follow OMB guidelines, which recommend a baseline that takes into account the effect of other laws and regulations.[1]

EPA's identification and examination of the Louisiana Open Bay dischargers are based on decisions presented in EPA's Development Document, which provides a list of permits and outfalls in Louisiana that are located in open bays. Some of these facilities may have already achieved zero discharge to comply with Louisiana state law, but EPA was unable to obtain information from LADEQ to ascertain these facilities' status. As a result, this analysis presents a worst-case scenario. The Texas Individual Permit applicant dischargers are those EPA identified

[1]OMB, 1996. Economic Analysis of Federal Regulations Under Executive Order 12866. January 11, p. 9.

as described in EPA's Development Document as having applied for individual permits allowing discharge, rather than complying with the existing General Permits requiring zero discharge of produced water in Texas.

Some Louisiana Open Bay and Texas Individual Permit applicant dischargers were included in the CWA Section 308 Survey, discussed in detail in Chapter Three of the PEIA. EPA therefore primarily bases its profiles of these groups on and obtains potentially affected well data from Section 308 Survey responses. This information was used to represent other similarly situated firms and wells, as discussed below.

To determine economic impacts on Louisiana Open Bay dischargers and Texas Individual Permit applicants on a well basis, EPA determined how many wells owned by these dischargers were surveyed, used information from the 308 Survey to estimate impacts on surveyed wells, and developed a "multiplier" to take into account additional Louisiana Open Bay wells and Texas Individual Applicant wells that were not surveyed. Each of these steps is detailed below.

First, in developing the Survey to apply to the whole coastal subcategory, EPA started with a list of wells determined to be in the coastal subcategory that had been completed since 1980 (and not recompleted since 1980) and were still productive (see PEIA, Chapter Two).[2]

[2]As noted in Chapter Two of the PEIA, EPA developed this list of wells using several computerized databases purchased and/or obtained from Tobin Surveys, Inc. (Tobin), Petroleum Information (PI), the Louisiana Department of Natural Resources (DNR), and the Texas Railroad Commission (RRC) (see Chapter Three for a discussion of the Coastal Subcategory). EPA defined an area in the Gulf of Mexico region likely to contain coastal wells to narrow down the data set for the Survey. The total number of wells in this area, however, was still very large, over 56,000. Of these, 10,582 wells completed or recompleted since 1980, and 26,861 wells completed prior to 1980, were active at some prior time. Because gathering information on all 27,000 wells would be a significant burden on the operators and on EPA, EPA limited its purchase of data to that for 11,000 post-1980 wells. It is likely that data searches by operators for pre-1980 wells would have been very time consuming, costing hundreds of thousands to millions of dollars. As it was, survey respondents indicated that data for some wells, typically older post-1980 wells, were difficult to obtain (Helpline Tracking Database; CBI data included in rulemaking record, Volume H-8). EPA also conducted a possible sensitivity analysis of production and discharge at the facility level (in addition to its well-level analysis), which EPA believes more accurately reflects the combination of pre-1980 and post-1980 wells at these facilities (see Section 10.3.2.5).

EPA sent the Survey to all owners of these wells. As part of the Survey, EPA asked the owners of sampled wells (see below) to tell EPA how many wells were associated with their treatment/separation facilities (either discharging or nondischarging). When respondents answered this question, they included both pre-1980 wells and post-1980 wells; thus, where both existed, EPA obtained this information. Based on this information, EPA estimated an average of 7.35 wells per discharging treatment/separation facility across the coastal subcategory in the Gulf of Mexico (see PEIA Chapter Three).

EPA determined the number of Louisiana Open Bay dischargers and Texas Individual Permit applicants as described in the Development Document. Because this information provided only the number of treatment/disposal facilities (82 outfalls in Texas and 82 outfalls in Louisiana),[3] EPA used the estimate of 7.35 wells per facility to estimate the total number of wells represented by Louisiana Open Bay dischargers and Texas Individual Permit applicants. This calculation results in an estimate of 603 wells in Texas and 603 wells in Louisiana. Since the factor of 7.35, takes into account both pre-1980 and post-1980 wells, the total well estimate represents production from both pre-1980 and post-1980 wells.

EPA did not perform a census of all wells, since the cost to the respondents to perform a census would have been exorbitant. Instead, before conducting the Survey, EPA stratified its sample (i.e., grouped wells into various categories before selecting some to be surveyed). A stratified sampling approach helps reduce the number of samples needed to produce reliable estimates. To stratify the samples, EPA looked at all the post-1980 wells determined to be currently producing in the coastal subcategory (roughly 2,600 in the Gulf of Mexico area), and then grouped the wells according to a variety of factors (such as major or small independent,[4] freshwater or saltwater). EPA then randomly selected several wells in each group (or stratum) and issued a detailed questionnaire asking the identified owner/operator to respond to technical

[3]This match on the number of outfalls between Louisiana Open Bays and Texas Individual Permits is coincidental. EPA assumes one outfall is associated with one treatment facility because this is usually the case.

[4]Small independents were identified as all operators who only had one coastal well identified in the list of wells.

information on the selected wells.[5] Each surveyed well was given a survey weight based upon how many wells it represented in its group (stratum). For example, in general, if the small independent group included a total of 10 wells and 2 wells were selected for sampling, each small independent well would represent 10/2 (or 5 wells, statistically), and each of the two wells would have a statistical weight of 5.0.

To evaluate economic impacts to the wells in the alternative baseline, EPA identified facilities included in the group of Texas Individual Permit applicants and Louisiana Open Bay dischargers that were included in the detailed Survey as well as the surveyed wells comprising those facilities. EPA then multiplied each Texas Individual Permit applicant well and Louisiana Open Bay discharger well that was surveyed by its Survey weight to determine that the surveyed Louisiana Open Bay discharging wells represent 167 of the 603 Louisiana Open Bay discharging wells and the surveyed Texas Individual Permit applicant wells represent 119 wells of the 603 Texas Individual Permit applicant wells. The surveyed wells, however, only represent the portion of those Texas Individual Permit applicant and Louisiana Open Bay discharger wells that were completed or recompleted since 1980, and do not account for the pre-1980 wells (those never recompleted since 1980). Thus to estimate the total economic impacts on the entire group, EPA took the economic information from the surveyed wells and multiplied it by 603/167 for Louisiana and 603/119 for Texas.

EPA has received comments arguing that the Section 308 Survey is not representative of the pre-1980 wells because these wells were not surveyed. The principal concern expressed in these comments was that pre-1980 wells, particularly those in Texas, are primarily "marginal producers" (i.e., they produced 10 bbls of oil per day or less, including those with zero oil and some gas, in 1992). Thus, the surveyed wells might misrepresent the limited production capacity and end-of-life situation of the pre-1980 wells. In fact, EPA did potentially capture some wells completed prior to 1980 that were recompleted after 1980. Additionally, EPA captured data from both pre- and post-1980 wells on a facility basis. Furthermore, EPA's analyses show that the older wells that have not been recompleted since 1980 are not likely to differ from the wells

[5]All operators associated with all wells in the list of wells were sent a survey to provide financial data (a census of all known operators).

captured in the Survey. For example, EPA determined that, among the surveyed wells in Texas that are operated by the Texas Individual Permit applicants, the 25th percentile well produced 3.2 bbls of oil per day, the 50th percentile (or median) well produced 6 bbls of oil per day, and the 75th percentile well produced 13 bbls of oil per day in 1992. That is, a majority of the Texas Individual Permit wells surveyed could be considered marginal producers according to the definitions given above, and thus marginal wells are well represented in the Survey. Using this Survey data to represent pre-1980 wells therefore will not appreciably overstate production or revenues, and will not exaggerate the pre-1980 wells' financial health.

Furthermore, for pre-1980 wells still in operation, EPA's estimate of a 15 percent decline rate for oil and gas production in the Gulf may be high. The Texas Railroad Commission[6] implies that the decline rate on Texas wells may be very much lower than 15 percent, stating that "many of these [marginal] wells have been producing at marginal rates for decades."[7] The decline rate is used to project not only declines in operating revenues in the financial model (see Section 10.3) but also to calculate increases in produced water production. Water production increases as oil (BOE) decreases to meet an assumption of a constant volume of fluids produced. Since costs are calculated on a dollar per barrel basis, as produced water volumes increase, costs increase (see Section 10.3 for more details). A lower decline rate will therefore also result in slower increases in O&M costs to dispose of produced water. If the actual decline rate is lower than 15 percent, the cost and impacts of the Coastal Guidelines on pre-1980 wells, and possibly on post-1980 wells, would be substantially lower than those estimated by the Agency in this FEIA, as well as in the PEIA.[8] Wells with a lower decline rate tend to be less likely to shut in the first year and to show production losses and more likely to show a positive NPV over the life of the project, postcompliance. If decline rates lower than 15 percent are prevalent in Texas,

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[6]Letter to Mr. Marvin Rubin, U.S. EPA, from Lori Wrotenbury, Railroad Commission of Texas, August 23, 1996.

[7]At a decline rate of 15 percent per year, the average productive life of a typical Gulf Coastal well would be between 25 and 30 years.

[8]EPA estimated impacts using a 1 percent and 2 percent decline rate. At a 2 percent decline rate losses were substantially less on a percentage basis, and at 1 percent, losses were lower still (Decline Rate Sensitivity Analysis of Louisiana Open Bay Dischargers and Texas Individual Applicants, ERG, Inc., October 1996).

EPA's calculations with respect to the pre-1980 wells (and possibly the post-1980 wells) using a 15 percent decline rate are likely to be conservative.

10.1.1 Louisiana Open Bay Dischargers—Wells, Treatment Facilities, Production, and Firms

The Louisiana Open Bay dischargers operate 82 outfalls under 37 permits and represent 22 firms. Each outfall is assumed to represent one treatment/separation facility that must meet a zero discharge requirement. As discussed above, when numbers of wells estimated using the Survey are extrapolated to represent the pre-1980 wells, EPA estimates that 603 wells are operating under the Louisiana Open Bay designation. This subset of the Gulf coastal population of wells is associated with lifetime production of 72 million BOE[9] in present value terms (PVBOE), or 103 million total BOE (undiscounted).

The 82 discharging treatment facilities operating in Louisiana Open Bays are currently associated with a total of 120.4 million bbls of produced water discharges annually, and with up to 180.6 million bbls per year over the next 10 years (see EPA's Final Development Document). Daily water production at these facilities ranges from 1 to 41,700 bpd. These facilities are currently meeting BPT requirements using equipment much like that described in Chapter Three for the Major Pass operators.

Of the 22 firms identified as Louisiana Open Bay dischargers, 17 (22 percent) are estimated to be small businesses with fewer than 500 employees.

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[9]BOE (barrels of oil equivalent) represents the total oil and gas produced, with gas converted to an equivalent measurement based on the amount of energy in a cubic foot of gas and the number of cubic feet of gas needed to match the energy in a barrel of oil. The present value of BOE (PVBOE) reflects BOE discounted to the present under the assumption that a barrel of oil today is worth more than a barrel of oil in the future. It is a useful measure to compare with other present value figures.

10.1.2 Texas Individual Permit Dischargers—Wells, Treatment Facilities, Production, and Firms

The Texas Individual Permit applicant dischargers that are associated with 82 outfalls have applied for 74 permits serving 603 wells (see EPA's Development Document). The production associated with these wells is estimated at 56 million PVBOE, or 79 million total BOE (undiscounted).[10]

The 82 discharging facilities in the Texas Individual Permit applicant category are estimated to discharge 24.9 million bbls of water annually (see EPA's Development Document). EPA projects this volume to increase to approximately 37.4 million bbls over the 10-year time frame of this analysis. Daily average discharges range from 1 to 9,316 bpd (see EPA's Development Document). On average, these facilities are smaller (i.e., have lower volumes of produced fluids) than those in the Louisiana Open Bay group (Section 308 Survey data).

A total of 40 firms are identified as Texas Individual Permit applicants. Thirty-nine (98 percent) of these are estimated to be small businesses.

10.1.3 Financial Profile of Louisiana Open Bay and Texas Individual Permit Firms

EPA developed a financial profile of the affected subgroups under the alternative baseline using detailed Survey responses from 28 of the 61 firms identified as either Louisiana Open Bay or Texas Individual Permit applicant dischargers. Although the Louisiana Open Bay and Texas Individual Permit applicant dischargers are a subset of all Section 308 operators in the Gulf, financial conditions in the two groups differ somewhat from those in the Survey as a whole, which represents all Gulf operators. A detailed discussion of financial conditions in the Gulf as a whole can be found in the PEIA.

[10]Louisiana Open Bay Discharger and Texas Individual Permit Applicant Production Loss Model Runs October, 1996 (CBI data; in CBI rulemaking record).

As Table 10-1 shows, median coastal revenues among Louisiana Open Bay/Texas Individual Permit applicant dischargers (not including majors) may be somewhat higher than those among the larger group of Section 308 Survey operators ($369,000 versus $179,000).[11] The median ratios of coastal revenues to total revenues (including revenues from other noncoastal operations as well as from other industrial designations, such as refining or contracting) may also be higher for the Louisiana Open Bay/Texas Individual Permit groups than for the Section 308 Survey group, but in neither group do firms appear to rely heavily on coastal revenues to support them.

Operating costs appear higher for operators in the Louisiana Open Bay and Texas Individual Permit applicants groups (except majors) as compared to the Section 308 Survey operators as a whole. This observation might be consistent with the Louisiana Open Bay and Texas Individual Permit applicant dischargers being involved in deep water operations. The Section 308 Survey data may include a higher proportion of firms primarily operating Chapman (on-land) wells and wells in relatively shallow water, which tend to be less expensive to operate than wells located in the deeper open bay waters. Gross profit margins appear slimmer among the Louisiana Open Bay/Texas Individual Permit applicant dischargers than among the Section 308 Survey population as a whole. This factor may make coastal operations among the Louisiana Open Bay and Texas Individual Permit dischargers relatively unimportant to the typical firm in terms of the firm's overall profitability, given the already very small portion of total firm revenues represented by coastal operations at a typical firm. In other words, if the typical firm were to shut in all its coastal operations, this action is unlikely to have a major impact on either revenues or earnings.

Given the possibility that the Louisiana Open Bay dischargers and Texas Individual Permit applicants experience higher operating costs, it is not surprising that they appear to be somewhat larger (with the exception of the majors and "other small independents") in terms of assets, owner equity, and working capital than the average operator in the wider Survey population (Table 10-2). This is especially true when the larger groupings (e.g., "all small

[11]No formal statistical tests have been performed to judge the statistical significance of these differences.

TABLE 10-1

MEDIAN FINANCIAL STATISTICS ON REVENUES AND COSTS
($ million 1995)

LOUISIANA OPEN BAY DISCHARGERS AND TEXAS INDIVIDUAL PERMIT APPLICANTS [c]					
Type of Firm	Number of Firms	Median Coastal Revenues	Median Ratio of Coastal Revenue to Total Revenue	Median Coastal Operating Costs	Median Ratio of Coastal Costs to Total Costs
Majors	4	$25,788	0.71%	$3,080	0.38%
Large independents [a]	1	Not reported	Not reported	Not reported	Not reported
Small corporate independents	13	$425	5.14%	$412	8.62%
Other small independents	10	$110	8.82%	$111	8.09%
All small independents	23	$286	7.06%	$282	8.53%
All independents	24	$300	7.11%	$283	8.09%
All firms [b]	28	$369	6.10%	$283	7.65%

ALL GULF OF MEXICO FIRMS IN THE SECTION 308 SURVEY [d]					
Type of Firm	Number of Firms	Median Coastal Revenues	Median Ratio of Coastal Revenue to Total Revenue	Median Coastal Operating Costs	Median Ratio of Coastal Costs to Total Costs
Majors	22	$29,959	0.60%	$6,658	0.36%
Large independents	10	$542	0.13%	$645	0.94%
Small corporate independents	59	$286	2.52%	$85	2.64%
Other small independents	122	$66	7.06%	$41	8.09%
All small independents	181	$110	4.68%	$63	6.49%
All independents	191	$110	4.35%	$63	4.43%
All firms [b]	213	$179	3.42%	$87	3.14%

[a] Numbers not presented in order to maintain confidentiality.
[b] Includes only firms for which financial information was available.
[c] Source: Section 308 Survey (CBI data; in CBI rulemaking record).
[d] Source: PEIA, Table 3-7. Dollars inflated from 1992 to 1995 using the Engineering News Record (ENR) Construction Cost Index.

TABLE 10-2

MEDIAN FINANCIAL STATISTICS ON ASSETS, EQUITY, AND WORKING CAPITAL
($ million 1995)

LOUISIANA OPEN BAY DISCHARGERS AND TEXAS INDIVIDUAL PERMIT APPLICANTS [c]					
Type of Firm	Number of Firms	Median Total Assets	Median Owner Equity	Median Working Capital	Median Current Ratio
Majors	4	$4,452,156	$1,509,165	($3,924)	0.9304
Large independents [a]	1	Not reported	Not reported	Not reported	Not reported
Small corporate independents	13	$112,301	$14,886	$1,590	1.0711
Other small independents	10	$1,275	$253	($43)	0.9310
All small independents	23	$15,602	$6,196	$230	1.0650
All independents	24	$17,841	$6,479	$150	1.0587
All firms [b]	28	$26,734	$11,314	$66	1.0524

ALL GULF OF MEXICO FIRMS IN THE SECTION 308 SURVEY [d]					
Type of Firm	Number of Firms	Median Total Assets	Median Owner Equity	Median Working Capital	Median Current Ratio
Majors	33	$4,891,718	$1,574,336	($7,851)	0.9304
Large independents	10	$1,327,825	$457,147	$20,731	1.1206
Small corporate independents	65	$59,825	$14,401	$1,299	1.2431
Other small independents	125	$2,034	$328	$7	1.0472
All small independents	190	$5,864	$728	$40	1.0711
All independents	200	$6,939	$1,021	$42	1.0711
All firms [b]	233	$14,856	$3,358	$36	1.0609

[a] Numbers not presented in order to maintain confidentiality.
[b] Includes only firms for which financial information was available.
[c] Source: Section 308 Survey (CBI data; in CBI rulemaking record).
[d] Source: PEIA, Table 3-5. Dollars inflated from 1992 to 1995 using the Engineering News Record (ENR) Construction Cost Index.

independents") are assessed. However, the current ratio, i.e., the ratio of short-term debt to working capital, calculated for these operators is slightly less than that calculated for the Section 308 Survey group, indicating that while the Louisiana Open Bay dischargers and Texas Individual Permit applicants have more working capital over all firms, their short-term debt is perhaps disproportionately greater than that of Section 308 operators as a whole.

Interestingly, Louisiana Open Bay dischargers and Texas Individual Permit applicants may be healthier financially than the Section 308 population as a whole. As Table 10-3 shows, nearly all categories of Louisiana Open Bay dischargers and Texas Individual Permit applicants for which information is reported appear to have better or substantially better return on assets, return on equity, and interest coverage ratios than operators in the Section 308 Survey group as a whole, although the interest coverage ratio over all firms is still below 3 (which indicates that they may have some difficulties sustaining more debt). Lenders and investors generally look for strong returns on assets and equity, and/or high interest coverage ratio (typically a ratio of 3 or greater indicates that the firm can easily handle more debt; as the interest coverage ratio declines, debt financing may become more difficult). Therefore, the firms in the alternative baseline appear possibly better positioned to raise capital than those in the larger Section 308 Survey group, although some firms may need to turn to equity or working capital (rather than debt) to finance pollution control capital equipment.

The numbers for majors, large independents, and small corporate independents can also be compared to 1992 Dun & Bradstreet benchmarks for the industry as a whole. According to Dun & Bradstreet, in 1992, average ROA[12] in the industry was 3.5 percent; the lowest quartile was -1.3 percent. For ROE, the average was 6.2 percent; the lowest quartile was -2.0 percent. (Nearly all data used to judge firm-level impacts are 1992 firm data from the Section 308 Survey, so 1992 Dun and Bradstreet data are used for comparability.) These average ROA and ROE figures are comparable to those calculated for majors, large independents, and small corporate independents (given in Table 10-3). Firms in the "other small independents" category cannot be compared because many of them are privately owned or S corporations, which are not included

[12]See Chapter Three for a detailed discussion of financial benchmarks used in analyzing firms.

TABLE 10-3

MEDIAN FINANCIAL STATISTICS ON PROFITABILITY AND ABILITY TO BORROW
($ million 1995)

LOUISIANA OPEN BAY DISCHARGERS AND TEXAS INDIVIDUAL PERMIT APPLICANTS [d]				
Type of Firm	Number of Firms	Median Return on Assets	Median Return on Equity	Median Interest Coverage Ratio
Majors	4	2.78%	7.19%	1.9039
Large independents [a]	1	Not reported	Not reported	Not reported
Small corporate independents	13	2.37%	6.22%	2.5038
Other small independents [b]	10	2.70%	7.34%	3.4240
All small independents	23	2.37%	2.32%	2.5038
All independents	24	1.76%	1.70%	2.4531
All firms [c]	28	2.34%	4.27%	2.4531

ALL GULF OF MEXICO FIRMS IN THE SECTION 308 SURVEY [e]				
Type of Firm	Number of Firms	Median Return on Assets	Median Return on Equity	Median Interest Coverage Ratio
Majors	22	2.24%	7.64%	2.9557
Large independents	10	0.90%	2.94%	1.0714
Small corporate independents	59	1.28%	3.03%	1.3265
Other small independents	122	0.02%	2.09%	1.1273
All small independents	181	0.82%	2.60%	1.2576
All independents	191	0.82%	2.60%	1.1735
All firms [c]	213	1.08%	3.47%	1.4394

[a] Numbers not presented in order to maintain confidentiality.
[b] Median return on equity calculated only on firms with postive equity.
[c] Includes only firms for which financial information was available.
[d] Source: Section 308 Survey (CBI data; in CBI rulemaking record).
[e] Source: PEIA, Table 3-9.

in Dun & Bradstreet's statistics. Thus, the Louisiana Open Bay and Texas Individual Permit dischargers' ROA and ROE medians are in the acceptable range for financial health and are near the median for comparable measures for the industry as a whole.

10.2 COSTS OF COMPLIANCE UNDER THE ALTERNATIVE REGULATORY BASELINE

Assuming that the Louisiana Open Bay dischargers see a change in state law authorizing discharge beyond January 1997, and this group and the Texas Individual Permit applicant dischargers receive individual permits authorizing discharge despite the no-discharge requirement of the 1995 Region 6 General Permits, the costs of compliance under the alternative regulatory baseline incorporate the costs required for these operations to achieve zero discharge of produced water/TWC. Zero discharge is achieved primarily by injection, but also, for smaller dischargers, by transporting produced water/TWC to commercial disposal facilities.[13] Total alternative baseline costs also include the costs, detailed in Chapter Four, for the Major Pass and Cook Inlet operations to meet the requirements of the regulatory options. Note that one Major Pass discharger, under the assumptions outline above for the alternative baseline, although required to go to zero discharge for the coastal portion of its produced water discharges under the current Region 6 General Permits might be considered a part of the group that could hypothetically receive an individual permit. Additional costs have been assigned to this Major Pass operator under the assumptions of the alternative baseline (see EPA's Development Document).

This section presents the costs to achieve zero discharge for Louisiana Open Bay dischargers, Texas Individual Permit applicants, and both of these groups combined. The section then summarizes EPA's estimates of costs to meet the selected regulatory options for all affected entities under the alternative baseline scenario.

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[13]EPA assumes small dischargers (less than approximately 100 BPD) will transport produced water/TWC to commercial facilities and estimates compliance costs accordingly (see EPA's Development Document).

The costs presented here are annualized costs. EPA has estimated these costs using the capital and O&M costs presented in the Development Document and the methodology described in Chapter Four.

Under the assumptions stated above, EPA estimates that the annual costs of meeting zero discharge requirements for the Louisiana Open Bay dischargers will total $28.1 million. The annual costs of meeting zero discharge for the Texas Individual Permit applicants will total $6.1 million.[14] Total costs under the alternative baseline are calculated by combining: 1) Louisiana Open Bay discharger and Texas Individual Permit applicant costs to meet produced water requirements with 2) zero discharge costs for certain Gulf coastal wells that might discharge TWC wastes in the absence of the Coastal Guidelines (see EPA's Development Document) to meet Option #2 TWC requirements (zero discharge) and 3) the costs for the Major Pass and Cook Inlet operations to meet Option #2 produced water/TWC requirements (zero discharge all except for discharge limitations, Cook Inlet) and (for Cook Inlet only) Option #1 drilling waste requirements (which is a no cost option). This last cost includes an additional $2.5 million per year to reflect the increased cost to one Major Pass discharger under the assumption of the alternative baseline. EPA estimates total alternative baseline costs of BAT and NSPS (for TWC waste only) to be $52.9 million.[15] Table 10-4 summarizes these costs. Note that these compliance costs are pretax costs and include costs to baseline and first-year shut-ins to install and operate pollution control equipment, costs that will not be incurred in reality.[16] These costs therefore represent a worst-case estimate of impacts on the Louisiana Open Bay dischargers and the Texas Individual Permit applicants.

The losses in NPV, discussed in Chapter Five and Section 10.3 of this FEIA, are a better estimate of the actual costs faced by producers. Loss in NPV is the difference between baseline

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[14]Based on costs presented in EPA's Development Document. Costs are calculated on the basis of a facility's produced water flow.

[15]Includes $0.6 million for costs associated with zero discharge under NSPS requirements for TWC wastes.

[16]In place of compliance costs, first-year shut-in facilities or platforms will experience production losses, which are accounted for in Chapter Five and Section 10.3 of this FEIA.

TABLE 10-4

TOTAL ANNUAL POLLUTION CONTROL COSTS UNDER THE ALTERNATIVE BASELINE SCENARIO (BAT AND NSPS COSTS[a]) ($ Millions 1995)

Option	Texas Individual Permit Dischargers	Louisiana Open Bay Dischargers	Total Texas/Louisiana Dischargers	Total Current Regulatory Baseline	Total Alternative Baseline Scenario
Produced Water/TWC					
Option #1	$6.1	$28.1	$34.2	$3.7	$37.9
Option #2	$6.1	$28.1	$34.2	$18.1	$52.3
Option #3	$6.1	$28.1	$34.2	$50.3	$84.6
Drilling Waste					
Option #1	$0	$0	$0	$0	$0
Option #2	$0	$0	$0	$9.2	$9.2
Total Selected Options					
Option #2/ Option #1	$6.1	$28.1	$34.2	$18.1	$52.3
NSPS	—	—	—	$0.6	$0.6
Total Selected NSPS and BAT	$6.1	$28.1	$34.2	$18.6	$52.9

[a]Includes an additional $2.5 million for a Major Pass discharger under the assumptions of the alternative baseline.

Source: ERG annualizations based on costs presented in EPA's Development Document.

and postcompliance NPV, where NPV is the sum of all cash inflows (revenues) minus the sum of all cash outflows (including any O&M compliance costs, capital expenditures, taxes, etc.) for a facility or a platform in present value terms. In postcompliance, revenues are reduced by production losses and cash outflows are increased by the post-tax expenditures on compliance costs (both O&M and capital costs). If a facility or platform shuts in in the first year, NPV losses will account for the loss of production but will not account for any compliance costs. Because the operator is assumed to make an economically rational decision, the NPV losses in this case will be less than the compliance costs estimated for the facility or platform.

10.3 PRODUCTION LOSS ANALYSIS IN THE ALTERNATIVE BASELINE SCENARIO

10.3.1 Description of the Economic Model for the Louisiana Open Bay and Texas Individual Permit Operators

EPA bases its estimates of impacts on the Louisiana Open Bay and Texas Individual Permit operators on analyses conducted at the well level, rather than at the platform/facility level, which is the case for the Cook Inlet and Major Pass operators.[17,18] The Agency estimates that approximately 1,206 productive wells in the Louisiana Open Bay and Texas Individual Permit categories (603 in each group) would be discharging produced water into coastal subcategory waters through one of the permitted treatment/separation facilities (under the assumptions discussed in Section 10.2 above).[19]

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[17]Appendix C provides a line-by-line description of the Open Bay/Individual Permit production loss model.

[18]EPA obtained data on wells identified as part of the Louisiana Open Bay and Texas Individual Permit Applicant dischargers group from the Section 308 Survey. The survey gathered data and survey weights were developed on a well basis. EPA found that determining facility-based statistical weights using the well-based weights might not lead to satisfactory estimates. A well-based approach tends to be more conservative than a facility-based approach since all wells are assumed to support their share (based on produced water volumes) of the pollution control costs (see discussion later in this section).

[19]For purposes of this analysis, facilities are defined in terms of outfalls. This definition may not match the definition used in the Development Document. This difference, however, has no (continued...)

To assess Open Bay discharger/Individual Permit Applicant economic impacts, EPA uses Section 308 Survey data, which contains a stratified sample of all wells operating in the region. Results from the analysis of each individual well have been weighted using Survey weights and then used to represent all 1,206 wells, as discussed in Section 10.1. Production and operations cost data, typical production and decline rates, oil and gas selling prices, and other model inputs in the analysis were taken from responses to the Section 308 Survey. For missing data or outliers, EPA substituted the average values calculated over the affected group. Where necessary, costs and prices have been inflated to 1995 dollars for comparison and inclusion with Cook Inlet/Major Pass impacts.

The Open Bay/Individual Permit model is similar to that used in examining the Cook Inlet and Major Pass operations, described in Chapter Five. Nevertheless, some basic differences exist between the two models.

As in the Cook Inlet/Major Pass analysis, incremental costs for produced water disposal are based on engineering and operating expenses that would be incurred by a production facility complying with the regulation. To distribute pollution control costs at the well level in the Open Bay/Individual Permit model, capital costs for compliance equipment are annualized over a 10-year period at 7 percent and added to annual operating and maintenance costs for compliance to compute an annual cost. This cost is divided by the total permitted discharge volume of the treatment facility to establish a cost per barrel of produced water that can be applied to the produced water volume that each well generates. Pollution control costs in the Open Bay/Individual Permit model thus become variable costs, as if all produced water were disposed of on a commercial basis.

Each well is assumed to produce a constant total combined volume of oil (in BOE, with gas converted to BOE), and water over its lifetime (see Appendix C). As the volume of oil (in BOE) declines, water production increases commensurately. Thus, the increase in the total volume of produced water is assumed to equal the decrease in total volume of oil (in BOE)

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[19](...continued)
effect on any analysis in which permit and facility are assumed equivalent for the purpose of estimating zero discharge costs.

produced (which declines an average of 15 percent per year). Since annual compliance costs are calculated by multiplying the annual produced water volume by the estimated compliance costs per barrel of produced water, annual compliance costs increase at a rate related to the decrease in oil and gas production.[20]

Furthermore, since the Open Bay/Individual Permit model is designed to investigate the effects of the regulation on the productive lifetime of a single well rather than on a facility, EPA does not use increases in production and costs due to drilling of new and recompleted wells in analyzing the facilities among the Louisiana Open Bay and Texas Individual Permit applicant dischargers as was done for Major Pass and Cook Inlet discharging operations.

Developmental wells, if drilled, are likely to be connected to an existing treatment/ separation facility. Operators of these new wells will face a very small cost to treat and inject the increases in produced water, so incremental costs for developmental wells will be relatively small. If a developmental well is reasonably successful, the oil and gas from that well will support the increased compliance costs for many years and thus impacts are likely to be small. EPA's analysis of Major Pass dischargers, for example, showed that when development was included in the model, impacts from pollution control costs that would occur without development were minimized.[21] If a well is not successful, it will not be produced, and therefore little expense for produced water disposal will be incurred. Some effects could be felt if development wells were found to be marginal producers, in which case they could shut in a little sooner under the Coastal Guidelines than they would without the rule, or some wells that would produce in the baseline might not produce. However, because this would occur only with marginal producers, only small increased costs would be sustained and little production would be lost.

[20]As in Chapter Five, baseline O&M costs (i.e., O&M costs exclusive of compliance costs) are held constant because, if a well produces a constant volume of oil (in BOE) and water (combined) every year, EPA assumes that the baseline costs of production will remain constant also.

[21]Major Pass Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

10.3.2 Produced Water/TWC

10.3.2.1 Louisiana Open Bay Operators

Baseline (Current Practice)

EPA's baseline analysis suggests that 37 of the 603 Louisiana Open Bay wells are not economical independent of this rule and are likely to have been shut in since the Survey was conducted.[22] EPA estimates total lifetime production from the remaining 566 wells to be 72.2 million discounted BOE (102.6 million total BOE) at baseline. The productive lifetimes of these wells total 8,801 years, or an average of 15.6 years per well for wells remaining open for one year or more (see Chapter Five and Appendix C for a more complete description of how a shut-in is determined).

EPA estimates that the present value of the Open Bay projects' net worth (NPV), assuming constant real wellhead prices, is $525.7 million (see Table 10-5 for a summary of baseline data; see Chapter Five for a discussion of NPV). The present value of federal income taxes collected over the economic lifetime of the Open Bay wells is $190.5 million. The present value of severance tax collected is $167.4 million. Royalties (present value) paid to the states and other leaseholders are $173.6 million.

Options #1, #2, and #3 (Zero Discharge)

Regulatory options #1, #2, and #3 all require zero discharge in the Louisiana Open Bays. When the compliance costs associated with meeting zero discharge requirements for produced water in the Louisiana Open Bays are added to the baseline operating costs for the model wells, 47 wells are estimated to shut in immediately[23] (in addition to those that close in

[22]See Sections 10.3.2.4 and 10.3.2.5 for a sensitivity analysis of baseline shut ins and other results presented below.

[23]Using alternative cost sharing assumption, EPA determined that no wells shift in post compliance (Sensitivity Analysis of Alternative Cost Sharing Assumptions; CBI data in (continued...)

TABLE 10-5

IMPACTS OF PRODUCED WATER OPTIONS
ON LOUISIANA OPEN BAY DISCHARGERS AND TEXAS INDIVIDUAL PERMIT APPLICANTS (1995 $)

Type of Impact	Louisiana Open Bays		Texas Individual Permits	
	Baseline Current Practice	Options #1, #2, & #3 Zero Discharge	Baseline Current Practice	Options #1, #2, & #3 Zero Discharge
Projected lifetime discounted production (PVBOE)	72,244,438	67,141,433	55,613,281	53,175,133
Change in discounted production (PVBOE)		5,103,005		2,438,149
Percentage change in discounted baseline production		7.1%		4.4%
Total projected lifetime production (BOE)	102,622,481	93,698,270	78,991,876	75,147,547
Change in total projected lifetime production (BOE)		8,924,211		3,844,330
Percentage change in total baseline production		8.7%		4.9%
Present value of project net worth (NPV) ($000)	$525,656	$433,863	$335,943	$301,058
Change in NPV ($000)		$91,794		$34,885
Percentage change in NPV		17.5%		10.4%
Productive wells in analysis	603	603	603	603
Baseline closures	37	—	367	—
Postcompliance closures	—	47	—	47
Total production lifetime (years)	8,801	4,978	2,856	2,067
Change in total production lifetime		3,824		789
Percentage change		43.4%		27.6%
Average lifetime (years, among wells not shutting-in in 1st year)	15.6	9.6	12.1	10.9
Change in average lifetime (among wells not shutting-in in 1st year)		6.0		1.1
Percentage change		38.3%		9.4%
Present value of severance and state income taxes collected ($000)	$167,355	$149,530	$44,599	$42,649
Change in present value of severance and state income taxes ($000)		$17,826		$1,950
Percentage change in severance and state income taxes		10.7%		4.4%
Present value of federal income taxes collected ($000)	$190,541	$162,904	$128,346	$119,235
Change in present value of federal income taxes ($000)		$27,637		$9,110
Percentage change in federal income taxes		14.5%		7.1%
Present value of royalties collected ($000)	$173,610	$155,944	$120,134	$112,655
Change in present value of royalties ($000)		$17,666		$7,479
Percentage change in royalties		10.2%		6.2%

Note: Results are weighted using well survey weights and adjustment factors noted in the text.

Source: Louisiana Open Bay Dischargers and Texas Individual Permit Applicants Production Loss Model Runs (CBI data; in rulemaking record).

the baseline). These first-year shut-ins, combined with a reduction in the total economic lifetime of the remaining wells from 8,801 years to 4,978 years (a 6.0 year change in average lifetime per well), leads to declines in production totaling 5.1 million discounted BOE (8.9 million total BOE), or a decline of 7.1 percent in present value baseline production. This production loss is associated with a $91.8 million loss in the present value of project net worth (17.5 percent).

The present value loss in federal income taxes collected is $27.6 million, or 14.5 percent of baseline present value federal income tax. Present value losses in severance and state income taxes are estimated at $17.8 million (10.7 percent of baseline), and present value losses in royalties collected are estimated at $17.7 million (10.2 percent of baseline). Table 10-5 summarizes these impacts.

In response to comments suggesting that a zero discharge requirement might have substantially lower impacts if its application to the Louisiana Open Bay dischargers were delayed, EPA calculated total production losses from operations shutting in under a zero discharge requirement in Years 1 through 5.[24] EPA estimates that total production losses would be reduced by 3.5 million PVBOE (4.9 million nondiscounted BOE), or 4.8 percent of total baseline production (PVBOE) from the Louisiana Open Bay dischargers, if these operators were allowed to discharge for five more years. That is, among Louisiana Open Bay dischargers, approximately 69 percent of production losses would be avoided with a five-year delay.

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[23](...continued)
rulemaking record). Postcompliance results change slightly: losses increase, but the percentage of losses decrease due to increased baseline production.

[24]Sensitivity Analysis of Delays in Implementation of Coastal Guidelines for Texas Individual Permit applicants and Louisiana Open Bay Dischargers (CBI data; in rulemaking record).

10.3.2.2 Texas Individual Permit Operators

Baseline (Current Practice)

EPA estimates that 367 of the 603 Texas Individual Permit wells are baseline closures (i.e., they are expected to close before compliance costs are incurred).[25] The remaining 236 wells are estimated to yield lifetime production of 55.6 million discounted BOE (79.0 million total). The productive lifetimes of these wells total approximately 2,856 years, or 12.1 years per well remaining open for one year or more (see Chapter Five and Appendix C for how a shut-in is determined).

EPA's baseline analysis indicates that the present value of the projects in the Texas Individual Permit category is $335.9 million. The present value of federal income taxes collected is $128.3 million, the present value of severance taxes collected is $44.6 million, and the present value of royalties collected is $120.1 million.[26]

Options #1, #2, and #3 (Zero Discharge)

EPA estimates that 47 Texas Individual Permit applicant wells will shut-in as a result of going to zero discharge, as required under all three options. The resulting decline in production among the Texas Individual Permit wells is estimated to be 2.4 million discounted BOE (3.8 million total, nondiscounted BOE), a 4.4 percent decrease from baseline discounted BOE production. The change in project present value (NPV) is estimated at $34.9 million, or 10.4 percent. Total productive lifetime of the wells in this category drops from 2,856 years to 2,067 years (from 12.1 years average to 10.9 years average per well).

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[25]See Sections 10.3.2.4 and 10.3.2.5 for a sensitivity analysis of baseline shut ins and other results presented below.

[26]No state income tax is applied to oil and gas revenues in Texas.

EPA estimates other losses associated with a zero discharge requirement as follows: $9.1 million in present value federal income taxes (7.1 percent); $2.0 million in present value severance taxes (4.4 percent); and $7.5 million in present value royalties (6.2 percent). Table 10-5 details these losses.

As with the Louisiana Open Bay dischargers, EPA calculated total production losses from Texas Individual Permit applicants shutting in under a zero discharge requirement in Years 1 through 5. EPA estimates that total production losses would be reduced by 2.2 million PVBOE (3.1 million nondiscounted BOE), or 4.0 percent of total baseline production (PVBOE) and 92 percent of the compliance cost of related decreases in production (PVBOE), if the Texas Individual Permit operators were allowed to discharge for five more years.

10.3.2.3 Combined Impacts

Table 10-6 shows the total produced water guidelines impacts for the Louisiana Open Bay and Texas Individual Permit dischargers combined. Since all three regulatory options require zero discharge of produced water from these operations, postcompliance results can be summarized in a single column.

Table 10-7 presents the impacts on Major Pass dischargers under the assumptions of the alternative baseline. As the table shows no additional production losses occur, but NPV declines from losses shown in Chapter Five (see Table 5-5).

Table 10-8 presents the impacts of the three produced water options on the alternative baseline as a whole (Louisiana Open Bay and Texas Individual Permit dischargers, Cook Inlet platforms, and Major Pass facilities). Although the Louisiana Open Bay and Texas Individual Permit operators incur the same costs (in terms of lost revenue and production) for all three regulatory options, the aggregate costs for the alternative baseline increase with option number

TABLE 10-6

IMPACTS OF PRODUCED WATER OPTIONS (1995 $)
(LOUISIANA OPEN BAY DISCHARGERS AND TEXAS INDIVIDUAL PERMIT APPLICANTS COMBINED)

Type of Impact	Total Louisiana and Texas	
	Baseline Current Practice	Options #1, #2, & #3 Zero Discharge
Projected lifetime discounted production (PVBOE)	127,857,719	120,316,566
Change in discounted production (PVBOE)		7,541,153
Percentage change in discounted baseline production		5.9%
Total projected lifetime production (BOE)	181,614,357	168,845,817
Change in total projected lifetime production (BOE)		12,768,541
Percentage change in total baseline production		7.0%
Present value of project net worth (NPV) ($000)	$861,599	$734,921
Change in NPV ($000)		$126,678
Percentage change in NPV		14.7%
Productive wells in analysis	1,206	1,206
Baseline closures	404	—
Postcompliance closures	—	94
Total production lifetime (years)	11,657	7,045
Change in total production lifetime		4,612
Percentage change		39.6%
Average lifetime (years, among wells not shutting-in in 1st year)	15	10
Change in average lifetime (among wells not shutting-in in 1st year)		5
Percentage change		31.5%
Present value of severance and state income taxes collected ($000)	$211,954	$192,178
Change in present value of severance and state income taxes ($000)		$19,776
Percentage change in severance and state income taxes		9.3%
Present value of federal income taxes collected ($000)	$318,887	$282,139
Change in present value of federal income taxes ($000)		$36,747
Percentage change in federal income taxes		11.5%
Present value of royalties collected ($000)	$293,744	$268,599
Change in present value of royalties ($000)		$25,145
Percentage change in royalties		8.6%

Note: Results are weighted using well survey weights and adjustment factors noted in the text.

Source: Louisiana Open Bay Dischargers and Texas Individual Permit Applicants Production Loss Model Runs (CBI data; in rulemaking record).

TABLE 10-7

IMPACTS OF PRODUCED WATER OPTIONS
ON MAJOR PASS FACILITIES
UNDER THE ALTERNATIVE BASELINE ASSUMPTIONS (1995 $)

Type of Impact	Baseline Current Practice	Gas Flotation Option #1	Zero Discharge Options #2 and #3
Projected lifetime discounted production (PVBOE)	434,713,377	434,713,377	432,592,658
Change in discounted production (PVBOE)	—	0	2,120,719
Percentage change in discounted baseline production	—	0.0%	0.5%
Total projected lifetime production (BOE)	599,860,713	599,860,713	596,461,487
Change in total projected lifetime production (BOE)	—	0	3,399,226
Percentage change in discounted baseline production	—	0.0%	0.6%
Present value of project net worth (NPV) ($000)	$1,459,603	$1,457,042	$1,398,504
Change in NPV ($000)	—	$2,560	$61,099
Percentage change in NPV	—	0.2%	4.2%
Number of facilities ceasing production in first year (postcompliance)	0	0	0
Total number of production years (1997 on)	82	82	79
Average production years per facility (all facilities)	10.3	10.3	9.9
Average production years per facility (nonclosing facilities)	10.3	10.3	9.9
Total production years lost among closing facilities	—	0	0
Total production years lost among nonclosing facilities	—	0	3
Present value of severance and state income taxes collected ($000)	$399,427	$399,259	$392,701
Change in present value of severance and state income taxes ($000)	—	$168	$6,726
Percentage change in severance and state income taxes	—	0.0%	1.7%
Present value of federal income taxes collected ($000)	$752,818	$751,987	$734,863
Change in present value of federal income taxes ($000)	—	$832	$17,956
Percentage change in federal income taxes	—	0.1%	2.4%
Present value of royalties collected ($000)	$815,892	$815,892	$809,434
Change in present value of royalties ($000)	—	$0	$6,458
Percentage change in royalties	—	0.0%	0.8%

Source: Major Pass Dischargers Production Loss Model Runs (CBI data; in rulemaking record).

TABLE 10-8

IMPACTS OF PRODUCED WATER OPTIONS ON ALTERNATIVE BASELINE (1995 $)

(COOK INLET PLATFORMS, MAJOR PASS FACILITIES, LOUISIANA OPEN BAY DISCHARGERS, AND TEXAS INDIVIDUAL PERMIT APPLICANTS)

Type of Impact	Option #1		Option #2		Option #3	
	Loss	Percent of Baseline Lost	Loss	Percent of Baseline Lost	Loss	Percent of Baseline Lost
Number of platforms/facilities shut in	94 wells	NA	94 wells	NA	94 wells 1 platform	NA
Discounted lifetime production lost (PVBOE)	8,613,248	1.0%	10,733,967	1.2%	19,128,262	2.2%
Total lifetime production lost (BOE)	15,172,123	1.2%	18,571,349	1.4%	35,570,719	2.8%
Present value of project net worth lost (NPV) ($000)	$141,122	4.5%	$199,660	6.3%	$342,532	10.8%
Present value of severance and state income taxes lost ($000)	$19,997	2.6%	$26,555	3.5%	$26,975	3.6%
Present value of federal income taxes lost ($000)	$42,551	2.8%	$59,674	3.9%	$122,523	8.1%
Present value of royalties collected ($000)	$27,136	1.8%	$33,594	2.2%	$49,166	3.2%
Total present value losses (including compliance costs) ($000)	$230,806	3.3%	$319,484	4.6%	$541,195	7.8%

Source: Cook Inlet Dischargers, Major Pass Dischargers, Louisiana Open Bay Dischargers, and Texas Individual Permit Applicants Production Loss Model Run (CBI data; in rulemaking record).

because costs for the Cook Inlet and Major Pass producers increase (discussed in Chapter Five).[27] As in Chapter Four, NPV analyses combine compliance costs and production losses. However, compliance costs for baseline and first year shut-ins are not included in NPV figures; these costs are included in the compliance cost analysis in Section 10.2.

As in Chapter Five, because Option #1 for drilling wastes is a no-cost option, the impacts of the selected options (Option #2 for produced water and Option #1 for drilling wastes) are the same as those for Produced Water Option #2 alone (see Table 10-9). Option #2 requires that Louisiana Open Bay and Texas Individual Permit dischargers and the Major Pass facilities achieve zero discharge of produced water; Cook Inlet platforms may continue to discharge, provided that they meet discharge limits equivalent to those for offshore operations.

The selected options are associated with 94 wells, but no platforms, shutting in relative to the alternative baseline. These 94 wells include 47 wells each in the Louisiana Open Bay and Texas Individual Permit categories. Losses in production under the selected options total 10.7 million discounted BOE (1.2 percent of total discounted BOE production at baseline) or 18.6 million total, non-discounted BOE. Present value losses in project net worth total $190.6 million, or 6.0 percent of baseline project NPV among the four alternative baseline groups. Note that these losses include the producers' share of compliance costs (post-tax costs).

The present value of federal income taxes lost is estimated at $57.2 million, or 3.8 percent of total federal taxes collected under the baseline scenario. The present value of state and severance taxes lost is estimated at $25.9 million (3.4 percent of baseline state and severance taxes collected). Finally, the present value of royalties lost to the states and other leaseholders amounts to $33.6 million, or 2.2 percent of projected baseline royalties. The total present value impacts of the selected options on the alternative baseline are estimated to be $307.3 million. Note that EPA considers additional impacts due to regulation of TWC wastes to be negligible (see Chapter Five in this FEIA).

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[27]Also note the small change in the Major Pass analysis due to higher costs of compliance assumed under the alternative baseline.

A more appropriate comparison is provided in Table 10-8 under the combined effects of compliance. In this table, the impacts on the affected operations are compared to a baseline that includes the entire coastal subcategory (without California and North Slope, Alaska), which includes the many operators who have already achieved zero discharge.[28]

Table 10-9 indicates that losses under the alternative baseline represent a very small portion of production, revenues, taxes, and royalties for all coastal oil and gas operations (excluding California and North Slope, Alaska). Under the selected options, lifetime production losses (both discounted and nondiscounted BOE) for the alternative baseline groups amount to 0.6 percent of total coastal production. NPV losses represent 4.2 percent of total coastal NPV. Other losses, as percentages of amounts estimated for all coastal oil and gas operations, are as follows: 1.1 percent of severance and state income taxes, 2.4 percent of federal income taxes, and 0.6 percent of royalties.

10.3.2.4 Sensitivity Analysis #1: Deletion of Suspect Data

EPA conducted a sensitivity analysis based on the deletion of suspect data. Two wells in the above analysis were believed to have faulty data. Unfortunately, these wells had very large survey weights and were estimated to represent about 200 wells overall (which is why the total number of baseline shut-in wells in Texas was so large in the preceding analysis). EPA removed these two wells from the analysis because their reported oil and gas production at the facility level would not support the operating costs reported, so the reported figures are not credible. Results from analysis of the remaining wells were extrapolated to represent the 200 wells instead. Thus the total number of wells (603) remained the same, but the number of wells used to model the total number of wells in Texas was reduced by two. The results of this analysis show a visible increase in the baseline production (3.6 million PVBOE versus 55.6 PVBOE).[29] All

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[28]Several court cases have established that the whole industry is the proper universe for comparing impacts.

[29]Sensitivity Analysis of Alternative Cost Allocation Assumptions for Louisiana Open Bay Dischargers and Texas Individual Permit Applicants.

TABLE 10-9

IMPACTS OF SELECTED OPTIONS (1995 $)

(COOK INLET PLATFORMS, MAJOR PASS FACILITIES, LOUISIANA OPEN BAY DISCHARGERS, AND TEXAS INDIVIDUAL PERMIT APPLICANTS)

Type of Impact	Produced Water Option #2	Drilling Waste Option #1	Total Impacts	Percent of Baseline Lost	Percent of Total Coastal Lost [a]
Number of platforms/facilities shut in	94 wells	0	94 wells	NA	NA
Discounted lifetime production lost (PVBOE)	10,733,967	0	10,733,967	1.2%	0.6%
Total lifetime production lost (BOE)	18,571,349	0	18,571,349	1.4%	0.6%
Present value of project net worth lost (NPV) ($000)	$199,660	$0	$199,660	6.3%	4.4%
Present value of severance and state income taxes lost ($000)	$26,555	$0	$26,555	3.5%	1.1%
Present value of federal income taxes lost ($000)	$59,674	$0	$59,674	3.9%	2.5%
Present value of royalties collected ($000)	$33,594	$0	$33,594	2.2%	0.6%
Total present value losses (including compliance costs) ($000)	$319,484	$0	$319,484	4.6%	2.1%

[a] The calculation of estimates for total Gulf coastal baseline production, NPV, state and severance tax paid, federal tax paid, and royalties is discussed in:
Jones, Anne, ERG, Memorandum to Matt Clark, U.S. EPA, dated August 2, 1996, entitled "Approximation of Total NPV, Taxes, Royalties, and Severance in the Gulf Coastal Region (All Operations)."
For this table, Cook Inlet baseline estimates were added to the Gulf estimates. Total coastal figures do not include coastal operations in California or North Slope, Alaska.

Source: Cook Inlet Dischargers, Major Pass Dischargers, Louisiana Open Bay Dischargers, and Texas Individual Permit Applicants Production Loss Model Runs (CBI data; in rulemaking record).

percentages remain the same as those seen in Table 10-5, but the absolute value of losses goes up (e.g., $5.8 million lost NPV vs. $3.8 million lost NPV). Additionally, the number of baseline shut ins changes from 367 to 247 for Texas and post-compliance shut ins change from 47 to 72 (these numbers change because baseline and post-compliance shut ins are distributed over the 200 wells represented by the suspect data).

EPA believes, however, that this analysis (as well as the original analysis) is too conservative because all wells are assumed to be required to support themselves independent of any other wells that might be served by the same facility. EPA has addressed the unnecessary conservatism of the original analysis and this sensitivity analysis by running another sensitivity analysis, which is described below.

10.3.2.5 Sensitivity Analysis #2: Alternative Cost Allocation at Facility Level

In the original production loss analysis, EPA has assumed that all wells must support themselves and has conservatively calculated that each well well's baseline O&M costs on the basis of the operator's average per-well O&M costs. Furthermore, EPA has assumed that the per-well cost of compliance is allocated on the basis of the volume of produced water generated by each well. At the treatment/separation facility level, however, marginal wells may be kept operating long past the point at which they can support themselves because their production continues to add to the NPV of the project as a whole (that is, in cases in which a facility handles a relatively large volume of oil and gas production, the larger producing wells can more than carry the costs of a few marginal wells).

This approach is substantiated by a very recent data submittal from the Texas Railroad Commission.[30] Although EPA could not perform a detailed analysis of these data before final action on the rule, a preliminary analysis showed that they support an assumption that facilities with substantial production serve a number of marginal wells that might have shut in earlier had

[30]EPA received data from the Texas Railroad Commission less than 1 week before signature of the Coastal Guidelines (facsimile transmittal from Leslie Savage, 10/24/96).

they been associated with single-well facilities or facilities with less production. The majority (76 percent) of the facilities listed in the data submittal were multiple-well facilities and/or served several leases. EPA noted a typical configuration in which one or two wells contributed the majority of production to the facility, with three or four additional wells providing marginal amounts of oil (10 bbls/day or less). A few wells were very marginal, with daily oil production under 2 bbls/day. Under EPA's previous assumptions, wells with this little production often were modeled as baseline shut-ins. EPA believes the configurations shown in the data support a facility-based approach, thus EPA's well-based approach is unnecessarily conservative.

In light of the high number of baseline shut-ins predicted in the previous analysis and the new data submittals from the Texas Railroad Commission, EPA looked more closely at each and every baseline shut-in well. EPA determined that many of the baseline shut-in wells are marginal, served by facilities with substantial levels of production (several hundreds of thousands of BOE, or more, per year). Then, instead of assuming that these marginal wells have average operating costs for the operator, EPA used the average operating cost per well and the number of wells at the facility reported in the Section 308 Survey to calculate a facility-level operating cost. EPA apportioned this operating cost to the well on the basis of each well's share of total facility production (i.e., if the facility produced 100,000 BOE annually and the well produced 1,000 BOE annually, the well would be assigned 1 percent of the operating costs).[31] Under such assumptions, many of the marginal, baseline shut-in wells were apportioned just a small fraction of these facilities' operating costs. In nearly all these cases, EPA found that the wells identified as baseline shut-ins in the well-based analysis no longer shut in, either in the baseline or postcompliance, even when supporting a share of compliance costs allocated on the basis of produced water flow. The few that could not support a share of compliance costs allocated on the basis of produced water flow could support compliance costs allocated on the basis of production (with the exception of a few wells in Louisiana representing the 16 post-compliance

[31]Sensitivity Analysis of Alternative Cost Allocation Assumptions for Louisiana Open Bay Dischargers and Texas Individual Permit Applicants (CBI data in rulemaking record).

shut in wells). Table 10-10 shows the results when operating costs (and, in rare instances, compliance costs) for some wells are reallocated on the basis of production levels.[32]

Table 10-10 can be compared to Table 10-5. As these tables show, lifetime production is slightly higher in Louisiana and substantially higher in Texas under the alternative facility-level cost allocation assumptions (103.1 BOE vs. 102.6 BOE in the original analysis for Louisiana and 121.0 BOE vs. 79.0 BOE in Texas). This occurs because the number of baseline shut-ins drops dramatically, from 367 in Texas to 8, and from 37 in Louisiana to zero; therefore, all of these wells that do not shut in continue producing. Furthermore, the number of postcompliance shut-ins also drops substantially, from 47 in each state to zero in Texas and 16 in Louisiana.[33] Overall, production and total dollar losses by category (i.e., NPV, taxes, royalties) drop in Louisiana, although they rise slightly in Texas (due to the greater baseline production), but both states show a reduction in the percentage losses for BOE, PVBOE, NPV, severance and state taxes, federal taxes, and royalties. Significantly, there are no shut ins and therefore no Type 3 loss of local employment; see Section 10.5.

Table 10-11 shows the results for both Texas and Louisiana combined, which can be compared to the results in Table 10-6. Overall, total baseline production for the two states combined is increased and, while the total losses resulting from the rule are slightly higher, the percentages lost are lower.

Because EPA made some simplifying assumptions by only adjusting operating costs for wells that were baseline shuts in in the previous analysis as well as adjusting operating and compliance costs for a few post-compliance wells that shut-in, these results may slightly understate baseline shut ins and overstate baseline production. EPA believes that, given the data

[32]This analysis also uses the adjustments to data made in sensitivity analysis #1, in which two wells in the survey that shut in in the baseline believed to be associated with suspect data were removed from the analysis.

[33]The numbers of baseline and postcompliance failures are more compatible with the results that EPA generated using the facility-based analysis than were the results of the previous analysis (Facility-Based Analysis of the Texas Individual Permit Applicants and Louisiana Open Bay Dischargers; CBI data in rulemaking record).

TABLE 10-10

IMPACTS OF PRODUCED WATER OPTIONS
ON LOUISIANA OPEN BAY DISCHARGERS AND TEXAS INDIVIDUAL PERMIT APPLICANTS,
RESULTS OF SENSITIVITY ANALYSIS USING ALTERNATIVE COST ALLOCATION ASSUMPTION (1995 $)

Type of Impact	Louisiana Open Bays		Texas Individual Permits	
	Baseline Current Practice	Options #1, #2, & #3 Zero Discharge	Baseline Current Practice	Options #1, #2, & #3 Zero Discharge
Projected lifetime discounted production (PVBOE)	72,561,217	67,616,454	85,325,401	82,372,135
Change in discounted production (PVBOE)		4,944,764		2,953,266
Percentage change in discounted baseline production		6.8%		3.5%
Total projected lifetime production (BOE)	103,117,736	94,260,289	120,996,365	116,055,260
Change in total projected lifetime production (BOE)		8,857,446		4,941,105
Percentage change in total baseline production		8.6%		4.1%
Present value of project net worth (NPV) ($000)	$529,094	$435,518	$513,415	$462,446
Change in NPV ($000)		$93,576		$50,969
Percentage change in NPV		17.7%		9.9%
Productive wells in analysis	603	603	603	603
Baseline closures	0	—	8	—
Postcompliance closures	—	16	—	0
Total production lifetime (years)	9,641	5,276	6,375	5,198
Change in total production lifetime		4,365		1,177
Percentage change		45.3%		18.5%
Average lifetime (years, among wells not shutting-in in 1st year)	16.0	9.0	10.7	8.7
Change in average lifetime (among wells not shutting-in in 1st year)		7.0		2.0
Percentage change		43.8%		18.5%
Present value of severance and state income taxes collected ($000)	$168,551	$150,840	$68,361	$66,082
Change in present value of severance and state income taxes ($000)		$17,711		$2,278
Percentage change in severance and state income taxes		10.5%		3.3%
Present value of federal income taxes collected ($000)	$192,280	$163,598	$195,269	$182,419
Change in present value of federal income taxes ($000)		$28,681		$12,850
Percentage change in federal income taxes		14.9%		6.6%
Present value of royalties collected ($000)	$173,732	$156,737	$184,498	$175,734
Change in present value of royalties ($000)		$16,994		$8,764
Percentage change in royalties		9.8%		4.8%

Note: Results are weighted using well survey weights and adjustment factors noted in the text.

Source: Sensitivity Analysis of Alternative Cost Allocation Assumption for Louisiana Open Bay Dischargers and Texas Individual Permit Applicants.

TABLE 10-11

IMPACTS OF PRODUCED WATER OPTIONS, RESULTS OF SENSITIVITY ANALYSIS USING ALTERNATIVE COST ALLOCATION ASSUMPTION (1995 $)
(LOUISIANA OPEN BAY DISCHARGERS AND TEXAS INDIVIDUAL PERMIT APPLICANTS COMBINED)

Type of Impact	Total Louisiana and Texas: Baseline Current Practice	Total Louisiana and Texas: Options #1, #2, & #3 Zero Discharge
Projected lifetime discounted production (PVBOE)	157,886,618	149,988,589
Change in discounted production (PVBOE)		7,898,030
Percentage change in discounted baseline production		5.0%
Total projected lifetime production (BOE)	224,114,100	210,315,549
Change in total projected lifetime production (BOE)		13,798,551
Percentage change in total baseline production		6.2%
Present value of project net worth (NPV) ($000)	$1,042,509	$897,965
Change in NPV ($000)		$144,544
Percentage change in NPV		13.9%
Productive wells in analysis	1,206	1,206
Baseline closures	8	—
Postcompliance closures	—	16
Total production lifetime (years)	16,017	10,474
Change in total production lifetime		5,542
Percentage change		34.6%
Average lifetime (years, among wells not shutting-in in 1st year)	13	9
Change in average lifetime (among wells not shutting-in in 1st year)		5
Percentage change		33.8%
Present value of severance and state income taxes collected ($000)	$236,911	$216,922
Change in present value of severance and state income taxes ($000)		$19,989
Percentage change in severance and state income taxes		8.4%
Present value of federal income taxes collected ($000)	$387,548	$346,017
Change in present value of federal income taxes ($000)		$41,531
Percentage change in federal income taxes		10.7%
Present value of royalties collected ($000)	$358,230	$332,472
Change in present value of royalties ($000)		$25,758
Percentage change in royalties		7.2%

Note: Results are weighted using well survey weights and adjustment factors noted in the text.

Source: Sensitivity Analysis of Alternative Cost Allocation Assumption for Louisiana Open Bay Dischargers and Texas In and Texas Individual Permit Applicants.

available, the results of this analysis should be a lower bound estimate of the impacts of the Coastal Guidelines. The results of the well-level analysis are an upper bound. The Agency believes that the actual results would be closer to those of the facility-level analysis than those of the well-level analysis, because, first, that is how operators actually manage their operations; second, wells shown as baseline facilities are still operating; and, third, data descriptions from the Texas Railroad Commission support this approach.

EPA performed one additional analysis using the facility-level cost allocation assumption. The Agency looked at the impact of creating a "stripper"-type (10 bbls/day oil production or less) category for coastal wells, which would not have to comply with the coastal rule, and assigned zero costs to wells producing 10 bbls/day of oil or less. This analysis was not very informative using the baseline created under the previous assumptions of self-supporting wells, because many of the marginal wells were determined to be baseline shut-ins. Using the alternative cost-allocation assumptions based on facility production levels, however, EPA was able to run this analysis, which showed slightly lower percentages of losses than those shown in Tables 10-10 and 10-11. The only major change was that the 16 Louisiana wells that shut in postcompliance (above) would not shut in under the assumption of no costs for marginal wells. The results of this analysis are available in the rulemaking record.[34] Because the wells are marginal, their additional longevity and production do not contribute significantly to the overall production for the Louisiana Open Bay discharger and Texas Individual Permit applicant groups.

10.4 FIRM-LEVEL IMPACTS UNDER THE ALTERNATIVE BASELINE SCENARIO

EPA uses a similar methodology to estimate firm level impacts under the alternative baseline as under the current regulatory baseline discussed in Chapter Six of this FEIA. Section 10.4.1 presents a review of EPA's general firm failure methodology and highlights some aspects of the analysis tailored specifically to determining firm level impacts among Louisiana Open Bay

[34]Sensitivity Analysis of Assigning Zero Costs to Wells Producing 10 bbls of Oil/Day or Less (CBI data in rulemaking record).

and Texas Individual Permit operators. Section 10.4.2 then summarizes the results of the alternative baseline analysis.

10.4.1 Analytical Methodology

As discussed in Chapter Six, EPA's firm failure methodology consists of three stages: a baseline analysis, a screening analysis, and a detailed analysis. EPA undertakes a detailed analysis only when the screening analysis indicates that an operator might incur substantial impacts. The detailed analysis enables EPA to better determine whether the potential impacts identified by the screening analysis are really expected to materialize.[35]

10.4.1.1 Baseline Methodology

The first stage of EPA's firm failure analysis, baseline analysis, is designed to eliminate baseline failure firms from the group of firms to be examined in a postcompliance scenario. Baseline failure firms are firms whose financial health is so precarious that they are likely to fail even without the added costs of regulation.

EPA assessed the alternative baseline using an approach that is slightly different from that applied to the current regulatory baseline since many more firms required analysis in the alternative regulatory baseline. For Louisiana Open Bay and Texas Individual Permit dischargers, EPA cross-referenced firms in the Section 308 Survey with known permit holders identified by EPA as discussed in EPA's Development Document. Firms in both databases were then investigated to determine the status of their equity and working capital. Working capital and equity are expected to be especially important means of financing pollution control costs in the Gulf region. Firms with negative equity and working capital are considered extremely weak

[35]As stated elsewhere, this rule will only be applicable to those operators when it would be applied to them in the NPDES permitting process. This analysis is especially conservative because the Texas Individual Permit Applicants and Louisiana Open Bay dischargers are already subject to zero discharge.

financially and likely to fail in the baseline. Additional baseline failures were subsequently identified during the detailed analysis that followed the screening analysis using cash flow and returns, among other factors, to identify financially weak firms.

10.4.1.2 Screening Methodology

EPA performed the screening analysis to identify firms for which impacts from compliance with the regulation are likely to be significant. As noted above, for the Louisiana Open Bay and Texas Individual Permit operators, EPA matched discharge permit holders by name to the Section 308 Survey respondents who provided financial data. In the screening analysis, the agency compared the annualized capital and operating and maintenance (O&M) costs for meeting the Coastal Guidelines requirements at all facilities owned by a firm identified as a Texas Individual Permit applicant or Louisiana Open Bay discharger facility to the equity and working capital of the affected firm (assuming financial data are available), and calculated the firm's percentage changes in equity and working capital.

Equity and working capital are common measures of a firm's ability to afford new projects or acquisitions. Equity is calculated as a firm's total assets minus its total liabilities (i.e., its net worth). Working capital is a measure of a firm's liquidity and is equal to current assets (typically cash or near-cash assets that can easily be liquidated) minus current liabilities (debts or other obligations due within one year). In other words, working capital describes available cash. If the annual cost of complying with a zero-discharge requirement contributes to a very small percentage change in equity or working capital at a firm, it is not likely that impacts at that firm will be substantial; i.e., the firm is not likely to fail as a result of compliance. Firms at which both equity or working capital would change by more than 5 percent are identified by EPA as needing further analysis. Since a firm can choose to finance some portion of compliance costs through either equity or working capital, as long as one measure does not change more than 5 percent, impacts should be minimal.

EPA uses this screening approach to limit the number of firms in the detailed analysis by eliminating firms from the analysis if they are expected to experience negligible impacts. By performing a detailed analysis on a small number of firms, EPA is able to engage in case-by-case assessments that allow for greater analytical flexibility than a computer model and that can circumvent some data limitations.

10.4.1.3 Detailed Analysis

EPA conducts a detailed analysis of the firms that seem to experience changes in both equity and working capital of more than 5 percent in the screener analysis. Detailed analysis allows EPA to better gauge whether these firms may be substantially affected by the Coastal Guidelines, since EPA cannot conclude that the firms will experience substantial impacts based solely on the screening analysis.

Firms showing a large drop in equity and/or working capital might not be as highly affected by the regulation as the screener analysis initially suggests for a number of reasons:

- The firms might be considered baseline failures; i.e., they might be firms that are likely to close even without the regulation in place because of their existing poor financial condition. These firms are eliminated from any additional analysis and are not considered to be affected by the rule.

- Wells tied into the permitted facility might currently be generating insufficient revenue to cover operating expenses. These wells would, in this case, be considered baseline shut-ins with associated production losses; i.e., they would be shut in regardless of the regulation. These types of losses also are not considered impacts from the zero-discharge requirements of the Coastal Guidelines.

- The regulatory requirements might be achieved more economically by shutting in production. This scenario is likely to result in minimal impacts when the revenue associated with the facility is a small portion of the firm's overall revenues. It is likely to occur, for example, when wells associated with the facility are marginal producers, providing minimal oil or gas but large quantities of produced water. In this case, the firm incurs the cost of plugging and abandoning the wells and loses a small portion of revenue—an impact attributable to the Coastal Guidelines, but potentially a much smaller impact than would be incurred if the wells were to continue production.

- The firm might be in a partnership with other firms or individuals and, thus, might incur only a fraction of the cost to meet zero discharge.

- The (surveyed) firm might be an operator only. Costs would be passed through to the owner companies or individuals.

- If only working capital is substantially affected, and the company is an S corporation, impacts might be overstated. It is to an S corporation's advantage to minimize working capital amounts on balance sheets when filing taxes; thus, balance sheet statements submitted in support of tax filings for S corporations are assumed to be at or near yearly minimums.

- The firm might have an unusually low equity or working capital situation relative to returns. When returns are analyzed in more detail,.they may show the ability of the company to absorb compliance costs without appreciably affecting its financial health.

EPA uses a variety of measures in its detailed analysis to assess impacts but focuses primarily on return on assets (ROA) and return on equity (ROE). These two ratios use net income divided by total firm assets and equity, respectively, as measures of return on investment in the firm. When post-compliance ROA or ROE range from adequate to good compared to industry averages, EPA estimates that no substantial impact will occur.

EPA bases its conclusions regarding impacts on the assumption that a promise of good returns can generally attract investment capital. ROE and/or ROA are common measures of the profitability of the firm and the ability of the firm to attract capital. A firm with an ROA or ROE above the lowest quartile for these ratios among the industry as a whole typically would not be in financial jeopardy (see Section 10.1.3).

Note that because most financial data from the Section 308 Survey are confidential, the impacts for individual companies cannot be listed by name. Summary statistics are presented instead because the aggregated nature of the statistics maintains confidentiality.

10.4.2 Results of Firm-Level Analysis

10.4.2.1 Louisiana Open Bay and Texas Individual Permit Dischargers

The results of three levels of analysis are presented here. Section 10.4.2.1 discusses the results of baseline analysis, Section 10.4.2.2 discusses the results of the screening analysis, and Section 10.4.2.3 discusses the results of the detailed analysis.

Baseline Analysis

Two of the 29 firms that provided detailed financial data in the Section 308 Survey and that were identified as Texas Individual Permit applicants or Louisiana Open Bay dischargers (6.9 percent) currently have both negative equity and negative working capital. These firms are considered very likely to fail regardless of whether any regulatory actions are taken. Both of the baseline failure firms are considered to be small businesses based on Small Business Administration (SBA) Guidelines ($\leq$500 employees). Thus, the 27 remaining firms are examined in the screening analysis.

Postcompliance Screening Analysis

In the screening analysis, all Louisiana Open Bay and Texas Individual Permit applicant firms matched in the analytical Survey database are investigated to determine changes in equity and working capital resulting from outlays for incremental disposal costs (produced water disposal costs). Results are broken down by size of firm.[36] Table 10-12 summarizes the results of this analysis for the 5 large and 22 small operators.

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[36]Size of operator was determined based on SBA's guidelines as to what constitutes a small firm in the oil and gas production industry ($\leq$500 employees is defined as small) and responses to employment questions in Chapter Three of the Survey. The one firm for which employee size is not known is assumed to fall into the small category.

TABLE 10-12

CHANGES IN EQUITY AND WORKING CAPITAL ASSOCIATED WITH ZERO DISCHARGE

(LOUISIANA OPEN BAY AND TEXAS INDIVIDUAL PERMIT DISCHARGERS ONLY)

Level of Change	Small Operators	Large Operators	Total
Change in Equity			
NA	0.00	0	0.00
<1%	6	5	11
1% to 5%	9	0	9
>10%	7	0	7
>5% to 10%			
Total	22	5	27
Change in Working Capital			
NA	8	0.00	8
<1%	4	4	8
1% to 5%	5	1	6
>5% to 10%			
>10%	5	0	5
Total	22	5	27

Source: Change in Equity and Working Capital Worksheet (CBI data; in rulemaking record).

NA = Negative equity or working capital.

None of the 27 firms that passed in the baseline analysis reported negative equity in the Survey. Broken down by size, all 5 of the large firms and 13 of the 22 small firms (59 percent) are expected to experience a change in equity of less than 5 percent. The change in equity among small firms ranges from 0.05 to 618 percent, with a median of 1.67 percent. The change in equity among large firms ranges from 0.03 to 0.11 percent, with a median of 0.09 percent (see Table 10-13).

Eight small firms, but no large firms, report negative working capital in the Survey. Among those with positive working capital, seven small firms (32 percent of the small firms analyzed) and all large firms are expected to experience changes in working capital of less than 5 percent. The change in working capital among small firms ranges from 0.07 to 220 percent, with a median of 5.87 percent. The change in working capital among large firms ranges from 0.36 to 3.09 percent, with a median of 0.63 percent (see Table 10-13).

Table 10-14 presents the number of small firms by their changes in equity and working capital.[37] As the table shows, 9 firms have changes in both working capital and equity of more than 5 percent. EPA selected all of these firms for further analysis. Additionally, EPA selected three firms where, although equity changed by less than 5 percent, working capital changed dramatically (annual pollution control costs were greater than baseline working capital) or working capital was negative in the baseline.

Detailed Analysis

Based on the above screening analysis, EPA analyzed the 12 small firms identified above in detail using their Survey responses in greater depth. Detailed analysis attempts to identify conditions such as those listed above that might indicate that the Coastal Guidelines would have different impacts than the basic analysis of equity and working capital suggests (none of the large firms in the Louisiana Open Bay and Texas Individual Permit groups are considered for further

[37]Large firms are not expected to have changes in either equity or working capital of more than 5 percent.

TABLE 10-13

RANGE AND MEDIAN CHANGE IN EQUITY AND WORKING CAPITAL ASSOCIATED WITH ZERO DISCHARGE

(LOUISIANA OPEN BAY AND TEXAS INDIVIDUAL PERMIT DISCHARGERS ONLY)

Operator Size	Minimum Change	Maximum Change	Median Change
Change in Equity			
Large operators	0.03%	0.11%	0.09%
Small operators	0.05%	618%	1.67%
All	0.03%	618%	0.96%
Change in Working Capital			
Large operators	0.36%	3.09%	0.63%
Small operators	0.07%	220%	5.87%
All	0.07%	220%	2.90%

Source: Change in Equity and Working Capital Worksheet (CBI data; in rulemaking record).

TABLE 10-14

COMBINED CHANGE IN EQUITY AND WORKING CAPITAL AMONG SMALL FIRMS

	Number
Equity <5%; Working Capital <5%	8
Equity <5%; Working Capital >5%[a]	5
Equity >5%; Working Capital <5%	0
Equity >5%; Working Capital >5%[b]	9

[a]Or working capital is negative.

[b]Includes one observation where working capital is not available. Equity change is very small, however, 0.11%, so EPA did not include this firm in the detailed analysis.

Source: Changes in Equity and Working Capital Worksheet (CBI data; in rulemaking record).

analysis since they are not estimated to have changes in their equity or working capital of more than 5 percent).

Table 10-15 presents the results of the in-depth analysis performed on these 12 firms. For reasons explained in the comment column in the table, 3 of these 12 firms are considered additional baseline failures and 1 additional firm is expected to have already plugged and abandoned the wells that are served by its discharging facility by the time the Coastal Guidelines take effect. Of the remaining 7 firms, 1 firm is expected to plug and abandon or sell its wells (if still economically viable) in response to the regulation. Note that the cost and tax savings to the firm of plugging and abandoning wells is not included in this analysis, but this cost is small (on a per well basis), the firm has few coastal wells, and the cost is a one-time cost that will not have a significant impact on cash flow over the time frame of analysis. EPA does not consider this firm to be significantly affected (i.e., experience firm failure), however, because coastal operations are a very small percentage of the firm's total revenues. Furthermore, this firm's returns, measured as ROA or ROE, are expected to be good, even after the revenue loss associated with compliance is taken into account (i.e., net income as a percentage of total assets or equity is much better than average for the industry).

Seven firms, shown in the last two columns in Table 10-15, might experience impacts from the regulation. Five of these firms are expected to be somewhat affected, but not to the extent that firm failure is likely. The two other firms might be substantially affected, but not enough information is available in the Survey data to judge whether this is definite. These two firms either have a very small stake in the wells they operate or have no stake and are operators only. It is possible therefore that little, if any, of the increased costs for operating pollution control equipment would be borne by these firms. If wells associated with these firms cease to operate, however, the firms might cease to receive revenues entirely (i.e., a firm that is only an operator might have no more wells to operate). EPA cannot determine whether the affected wells would be profitable to operate once the regulation is promulgated because none of these particular wells were surveyed. Therefore, the potential impact to these two firms ranges from minor (e.g., some lost revenues) to major (i.e., firm failure).

TABLE 10-15

RESULTS OF FURTHER FINANCIAL ANALYSIS OF
SELECTED COASTAL REGION OIL AND GAS PRODUCTION OPERATORS
(LOUISIANA OPEN BAY AND TEXAS INDIVIDUAL PERMIT DISCHARGERS)

Firm No.	Likely Baseline Firm Failure	Likely Baseline P&A*	Likely to P&A or Sell Properties in Response to Permit but Not Firm Failure	Some Impact but Not Firm Failure	Possible Firm Failure but Need More Information	Firm Failure	Comments
1		X					Current loss in coastal portion of business; firm likely to plug and abandon wells; other business appears healthy.
2					X		Did not provide enough info. in survey to make judgment.
3				X			Analysis shows large change in working capital, but working capital unusually low, probably because used to pay for workover. If cost of workover ignored, impact on working capital still high (over 30%) but change in equity very low and return on assets and return on equity still likely to be good compared to industry average. Is an S corporation, so change in working capital less of an issue.
4					X		Very complex financial picture; only takes about a 10% share of net revenues from wells operated.
5	X						Negative earnings, negative net income, negative working capital.
6	X						Negative earnings, negative net income, negative working capital.
7			X				Impacts from plug and abandoning wells and lost revenues, but return on assets and return on equity still likely to be very good relative to industry averages post-compliance.

TABLE 10-15 (continued)

Firm No.	Likely Baseline Firm Failure	Likely Baseline P&A*	Likely to P&A or Sell Properties in Response to Permit but Not Firm Failure	Some Impact but Not Firm Failure	Possible Firm Failure but Need More Information	Firm Failure	Comments
8				X			Return on assets still very strong after compliance costs are incurred.
9	X						Very low ROA (0.04%), ROE (0.05%), ICR=1.04; interest payments nearly equal to earnings.
11				X			Returns still good after pollution control costs are taken into account. Although working capital is negative, equity changes only minimally (1.36%).
12				X			Returns still good after pollution control costs are taken into account. Although working capital is negative, equity changes only minimally (1.36%).
14				X			Large dryhole abandonment costs expended in 1992. If adjusted for expended item, ROA would be adequate both before and after pollution control costs.

Note: Shaded columns indicate possible firm failure (used in the estimate of firms that might experience substantial impact).

Source: Section 308 Survey Questionnaires; (financial section). Annualized costs based on EPA's Development Document for each affected facility.

EPA concludes that, under zero discharge, a range of 0 to 2 firms might experience firm failure, out of a total of 27 discharging firms examined in this analysis. To account for the number of firms not captured in this analysis, EPA extrapolates this estimate of the number of firm failures to the full universe of Louisiana Open Bay and Texas Individual Permit operators.[38] The single potentially failing Louisiana Open Bay operator captured in the analysis represents one operator in the full universe, while the one Texas Individual Permit failing operator captured in the analysis represents three operators in the full universe, yielding a total of 0 to 4 failing firms. These potentially substantially affected firms represent 0 to 6.6 percent of all Louisiana Open Bay and Texas Individual Permit operators (61 firms, both large and small), although at most, this is less than 1 percent of the 417 firms estimated to be operative in the Gulf coastal area after eliminated baseline firm failures (see the PEIA) and Chapter Eleven of the FEIA. The upper estimate of 4 firm failures assumes that firms for which information is lacking will be substantially affected. Considering the level of uncertainty associated with the data, a range of 0 to 4 failures might therefore overstate impacts (e.g., some of these 0 to 4 firms might not be appreciably affected if their wells remain operative and costs are passed through to several owners). It will not understate impacts.

10.4.2.2 Alternative Baseline

To estimate the impacts on firms under the entire alternative baseline scenario, EPA adds the results of its Louisiana Open Bay/Texas Individual Permit analysis to results estimated for the current regulatory baseline. As discussed in Chapter Six, under the current regulatory baseline, EPA found no firm failures given the selected regulatory options. Even with the greater costs to one firm under the assumption of the alternative baseline, EPA finds no firm failures among Major Pass dischargers.[39] Thus for the selected regulatory options under the

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[38]There were a total of 12 surveyed Texas Individual Permit Applicant firms out of 40 total such firms in Texas and 17 surveyed Louisiana Open Bay discharging firms out of 22 total such firms in Louisiana. EPA assumed that the firms were representative of those not surveyed and thus each Texas firm was estimated to represent approximately three (40/12) firms and each Louisiana firm was estimated to represent one (22/17).

[39]Cash Flow Analysis of Major Pass Dischargers (CBI data; in rulemaking record.

alternative baseline scenario, EPA estimates that 0 to 4 firms might be substantially affected by the Coastal Guidelines under the alternative baseline analysis.

10.5 NATIONAL AND REGIONAL EMPLOYMENT IMPACTS AND TOTAL OUTPUT LOSSES

10.5.1 National-Level Output and Employment Impacts

The Coastal Guidelines may cause four types of changes (losses) in employment and output, some of which are offset by gains, and some of which are not (dead weight losses). These four types of changes, discussed in detail for Texas and Louisiana in the sections to follow, include:

- *Type 1—Compliance Costs:* Direct oil and gas employment losses due to expenditures diverted to compliance.
- *Type 2—Production Losses:* Employment and output losses due to production losses at operations that install and operate pollution control equipment. Losses in production are a result of shortened postcompliance lifetimes.
- *Type 3—First Year Shut-ins:* Employment and output losses due to production losses from operations that shut-in in the first year and do not install pollution control equipment.
- *Type 4—Delayed Investment:* Employment and output losses associated with delayed investment, i.e., where the need for pollution control expenditures delays investment in oil and gas exploration and development.

Changes in output in the oil and gas industry affect national-level output and employment. To calculate the effects of a change in oil and gas industry output on national-level output across all industries under the assumptions of the alternative baseline, EPA uses the same multiplier used in Chapter Seven, 1.9420 (RIMS II National Multipliers). This figure represents the loss of an additional $0.94 across all industries for each $1 decrease in output in the oil and gas industry. Similarly, to calculate national-level employment changes based on changes in oil and gas industry output, EPA uses the BEA multiplier of 13.0 jobs per million dollars (RIMS II National Multipliers), which reflects the change in national-level employment given a $1 million change in industry output. The methodology used in this chapter is identical to that discussed in Chapter Seven.

At the national level, employment losses associated with the direct transfer of labor resources away from production wells are matched by equivalent gains in employment to operate injection wells. Additionally, on a national basis, losses from first-year shut-ins are offset by gains elsewhere in the economy as the investment in production at these wells is reallocated to other productive investments. Because the only measurable net employment changes are those associated with output losses, EPA estimates only Type 2 (based on production losses from premature well closures, as compared to baseline) and Type 4 losses (delayed investment losses). Regional employment effects are characterized somewhat differently and are estimated in Section 10.5.2.

10.5.1.1 National Level Output Losses

National-level output losses due to production losses (Type 2) and investment delays (Type 4) are presented in Tables 10-16 and 10-17 and summarized below:

- Type 2 output losses—output losses for the U.S. economy are estimated at $26.6 million per year for Louisiana Open Bay dischargers. For Texas Individual Permit applicants, EPA estimates output losses for the U.S. economy of $11.1 million per year. Losses are estimated at $37.8 million per year for both groups combined. Adding Major Pass and Cook Inlet impacts, EPA estimates $57.2 million per year will be lost under the assumptions of the alternative baseline (see Table 10-16).

- Type 4 output losses—Using the method discussed in Section 7.1.2 of this FEIA, EPA estimates that delayed investment will result in reduced annualized returns to the industry of $1.2 million in Louisiana and $0.3 million in Texas. These losses are associated with a total reduction in U.S. output of $2.9 million per year ($2.4 million for Louisiana Open Bay dischargers and $0.5 million for Texas Individual Permit applicants). For all groups (including Cook Inlet and Major Pass dischargers), the loss is $4.4 million annually (see Table 10-17).

TABLE 10-16

NATIONAL OUTPUT LOSSES ASSOCIATED WITH
POSTCOMPLIANCE PRODUCTION LOSSES
FOR THE ALTERNATIVE REGULATORY BASELINE UNDER THE SELECTED OPTIONS
(MAJOR PASS FACILITIES, COOK INLET PLATFORMS, LOUISIANA OPEN BAY DISCHARGERS, AND TEXAS INDIVIDUAL PERMIT APPLICANTS)
(1995 $)

	Annualized production loss (BOE) [b]	Annualized industry output (revenues) lost ($000)	Final-demand output multiplier [c]	Annualized national-level output effects ($000)
Louisiana [a]	623,661	$13,720.5	1.9420	$26,645.3
Texas	260,754	$5,736.6	1.9420	$11,140.5
Total Louisiana and Texas	884,415	$19,457.1	1.9420	$37,785.8
Total Alternative Baseline	1,339,000	$29,458.0	1.9420	$57,207.4

[a] Excluding Major Pass operators.

[b] Minus first-year shut-in losses of 722,673 PVBOE (102,892 BOE annually) for the Louisiana Open Bay Dischargers and 606,719 PVBOE (86,383 BOE annually) for the Texas Individual Permit Applicants.

[c] Represents the total dollar change in output that occurs in all industries for each dollar change in output delivered to final demand by the oil and gas industry.

Sources: Major Pass Dischargers Production Loss Model Runs, Cook Inlet Dischargers Production Loss Model Runs, Louisiana Open Bay Dischargers Production Loss Model Runs, and Texas Individual Permit Applicants Production Loss Model Runs (CBI data; in rulemaking record).

Bureau of Economic Analysis. 1996. Table A-2.4. -- Total Multipliers, by Industry Aggregation, for Output, Earnings, and Employment. Regional Input-Output Modeling System (RIMS II), Regional Economic Analysis Division.

TABLE 10-17

NATIONAL OUTPUT LOSSES ASSOCIATED WITH
DELAYED PRODUCTION FOR THE ALTERNATIVE REGULATORY BASELINE
UNDER THE SELECTED OPTIONS
(MAJOR PASS FACILITIES, COOK INLET PLATFORMS, LOUISIANA OPEN BAY DISCHARGERS, AND TEXAS INDIVIDUAL PERMIT APPLICANTS)
(1995 $)

	Annualized industry output (revenues) lost ($000)	Final-demand output multiplier [b]	Annualized national-level output effects ($000)
Louisiana [a]	$1,210.7	1.9420	$2,351.2
Texas	$263.3	1.9420	$511.3
Total Louisiana and Texas	$1,474.0	1.9420	$2,862.5
Total Alternative Baseline	$2,251.4	1.9420	$4,372.2

[a] Represents the total dollar change in output that occurs in all industries for each dollar change in output delivered to final demand by the oil and gas industry.

[b] Represents the total dollar change in output that occurs in all industries for each dollar change in output delivered to final demand by the oil and gas industry.

Sources: Major Pass Dischargers Production Loss Model Runs, Cook Inlet Dischargers Production Loss Model Runs, Louisiana Open Bay Dischargers Production Loss Model Runs, and Texas Individual Permit Applicants Production Loss Model Runs (CBI data; in rulemaking record).

Bureau of Economic Analysis. 1996. Table A-2.4. -- Total Multipliers, by Industry Aggregation, for Output, Earnings, and Employment. Regional Input-Output Modeling System (RIMS II), Regional Economic Analysis Division.

10.5.1.2 National-Level Employment Impacts

National-level employment losses due to production losses (Type 2) and investment delays (Type 4) are presented in Tables 10-18 and 10-19 and summarized below:

- Type 2 employment losses—EPA estimates national employment losses of 163 FTEs associated with Louisiana Open Bay dischargers and 68 FTEs associated with Texas Individual Permit applicants (231 FTEs combined) due to production losses. Adding in losses associated with Major Pass and Cook Inlet dischargers, Type 2 national-level employment impacts under the assumptions of the alternative baseline total 350 FTEs (see Table 10-18).

- Type 4 employment losses—EPA estimates losses of 14 FTEs associated with Louisiana Open Bay discharges, 3 FTEs associated with Texas Individual Permit applicants (17 FTEs combined), and 27 FTEs associated with all groups due to investment delays under the assumptions of the alternative baseline (see Table 10-19).

10.5.1.3 Total National-Level Output and Employment Impacts

EPA estimates total national-level output losses associated with Louisiana Open Bay dischargers and Texas Individual Permit applicants to be $40.6 million. Adding these to Major Pass and Cook Inlet impacts, EPA estimates that total output under the alternative regulatory baseline is reduced by $61.6 million, which is 0.001 percent of estimated gross domestic product (GDP) of $6.6 trillion and 0.1 percent of oil and gas industry's contribution to GDP in 1992.[40] In addition, EPA estimates that 377 FTEs will be lost. This represents only 0.0003 percent of total 1995 U.S. employment of 124.9 million persons[41] (see Table 10-20 for a summary of these losses).

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[40]numbers inflated, but not otherwise adjusted, from 1992 to 1995. The most recent year for which data were available on the oil and gas industry's contribution to GDP was 1992. See: Tables Nos. 700 and 1173 in the Statistical Abstract of the United States. U.S. Department of Commerce, Bureau of the Census, September 1995.

[41]communication between ERG and the Bureau of Labor Statistics (BLS), July 24, 1996.

TABLE 10-18

NATIONAL EMPLOYMENT LOSSES
ASSOCIATED WITH LOST OUTPUT (TYPE 2 LOSSES) FOR THE
ALTERNATIVE REGULATORY BASELINE UNDER THE SELECTED OPTIONS
(MAJOR PASS FACILITIES, COOK INLET PLATFORMS, LOUISIANA OPEN BAY DISCHARGERS, AND TEXAS INDIVIDUAL PERMIT APPLICANTS)

	Annualized industry-level output effects ($000 1995)	Annualized industry-level output effects ($000 1992) [b]	Final-demand employment multiplier [c]	Total annual employment losses (FTEs)
Louisiana [a]	$13,720.5	$12,501.7	13.0	163
Texas	$5,736.6	$5,227.0	13.0	68
Total Louisiana and Texas	$19,457.1	$17,728.7	13.0	231
Total Alternative Baseline	$29,458.0	$26,841.2	13.0	350

[a] Excluding Major Pass operators.
[b] Output values deflated from 1995 dollars to 1992 dollars because the Bureau of Economic Analysis employment multipliers are based on 1992 data.
[c] Represents the total change in number of jobs that occurs in all industries for each $1 million change in output delivered to final demand by the oil and gas industry.

Sources: Table 10-16 in this FEIA.
Bureau of Economic Analysis. 1996. Table A-2.4. -- Total Multipliers, by Industry Aggregation, for Output, Earnings, and Employment. Regional Input-Output Modeling System (RIMS II), Regional Economic Analysis Division.

TABLE 10-19

NATIONAL EMPLOYMENT LOSSES
ASSOCIATED WITH DELAYED PRODUCTION (TYPE 4 LOSSES) FOR THE
ALTERNATIVE REGULATORY BASELINE UNDER THE SELECTED OPTIONS
(MAJOR PASS FACILITIES, COOK INLET PLATFORMS, LOUISIANA OPEN BAY DISCHARGERS, AND TEXAS INDIVIDUAL PERMIT APPLICANTS)

	Annualized industry-level output effects ($000 1995)	Annualized industry-level output effects ($000 1992) [b]	Final-demand employment multiplier [c]	Total annual employment losses (FTEs)
Louisiana [a]	$1,210.7	$1,103.2	13.0	14
Texas	$263.3	$239.9	13.0	3
Total Louisiana and Texas	$1,474.0	$1,343.1	13.0	17
Total Alternative Baseline	$2,251.4	$2,051.4	13.0	27

[a] Excluding Major Pass operators.
[b] Output values deflated from 1995 dollars to 1992 dollars because the Bureau of Economic Analysis employment multipliers are based on 1992 data.
[c] Represents the total change in number of jobs that occurs in all industries for each $1 million change in output delivered to final demand by the oil and gas industry.

Sources: Table 10-17 in this FEIA.
Bureau of Economic Analysis. 1996. Table A-2.4. -- Total Multipliers, by Industry Aggregation, for Output, Earnings, and Employment. Regional Input-Output Modeling System (RIMS II), Regional Economic Analysis Division.

TABLE 10-20

SUMMARY OF NATIONAL EMPLOYMENT AND OUTPUT LOSSES FOR THE ALTERNATIVE REGULATORY BASELINE UNDER THE SELECTED OPTIONS

(MAJOR PASS FACILITIES, COOK INLET PLATFORMS, LOUISIANA OPEN BAY DISCHARGERS, AND TEXAS INDIVIDUAL PERMIT APPLICANTS)

(1995 $)

	Annualized production losses (BOE)	Annualized industry output (revenue) losses ($000)	Annualized national-level output losses ($000)	Annual Reduction in FTEs
Type 1 Losses [a]	--	--	--	--
Type 2 Losses	1,339,000	$29,458.0	$57,207.4	350
Type 3 Losses [a]	--	--	--	--
Type 4 Losses [b]	--	$2,251.4	$4,372.2	27
Total Losses	1,339,000	$31,709.4	$61,579.6	377

[a] Type 1 and Type 3 losses are not calculated in this FEIA because any losses and gains are assumed to offset each other on the national level.

[b] Type 4 production losses are not calculated.

Sources: Tables 10-16, 10-17, 10-18, and 10-19 in this FEIA.

10.5.2 Regional Employment Impacts

In this section, EPA evaluates the magnitude and significance of job losses on the regional level (see Chapter Seven for a description of the methodology). EPA assumes that Type 1 losses result in gains elsewhere in the regional economy as production employees are shifted into operating injection well equipment. Thus there are no net employment changes due to Type 1 losses. Type 2 and Type 4 losses are used to estimate employment losses in this subsection as they were in Section 10.5.1. The only major difference in EPA's analysis of Type 2 and Type 4 losses at the regional level is that regional (state) multipliers are used in place of the national-level multipliers. EPA assumes that investments associated with Type 4 losses would have occurred in the region in the absence of the Coastal Guidelines, although this might not be the case.

First-year shut-ins and firm failures (Type 3 losses) are also evaluated at the regional level. On a national level, Type 3 losses are offset by gains elsewhere as investment is reallocated to other productive investments in the economy, but EPA assumes that there are no offsetting gains in the regional economy for Type 3 losses. EPA evaluates Type 2, Type 3, and Type 4 losses in subsections below.

10.5.2.1 Type 2 and Type 4 Regional Employment Losses

Using the Type 2 production losses shown in Table 10-16 above, and regional multipliers for Louisiana and Texas, where appropriate, where appropriate, instead of national multipliers,[42] EPA calculates Type 2 losses of 100 FTEs for Louisiana and 46 FTEs for Texas, for a total of 146 FTEs for both groups combined. EPA estimates annual Type 4 employment losses of 9 FTEs in Louisiana and 2 FTEs in Texas using the output loss figures shown in Table 10-14 and regional multipliers, for a combined Type 4 loss of 11 FTEs (jobs) annually in the Gulf as a result of this rule (see Tables 10-21 to 10-25).

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[42](state) multipliers are lower than national multipliers because a smaller portion of vendor industries are located in each state.

TABLE 10-21

SUMMARY OF REGIONAL EMPLOYMENT AND OUTPUT LOSSES FOR THE LOUISIANA OPEN BAY DISCHARGERS UNDER THE SELECTED OPTIONS

	Annualized production losses (BOE)	Annualized industry output (revenue) losses (S000 1995)	Annualized industry output (revenue) losses (S000 1989) [c]	Annual Reduction in FTEs
Type 1 Losses [a]	--	--	--	--
Type 2 Losses	623,661	$13,720.5	$11,573.8	100
Type 3 Losses	--	--	--	11 to 30
Type 4 Losses [b]	--	$1,210.7	$1,021.3	9
Total Losses	623,661	$14,931.2	$12,595.1	120 to 139

[a] Type 1 losses are not calculated in this FEIA because any losses and gains are assumed to offset each other on the national level.
[b] Type 4 production losses are not calculated.
[c] Output values deflated from 1995 dollars to 1989 dollars because the Bureau of Economic Analysis regional employment multipliers use 1989 dollars.

Sources: EPA analyses described in text; Tables 10-16, 10-17, 10-18, and 10-19 in this FEIA.

TABLE 10-22

SUMMARY OF REGIONAL EMPLOYMENT AND OUTPUT LOSSES FOR THE TEXAS INDIVIDUAL PERMIT APPLICANTS UNDER THE SELECTED OPTIONS

	Annualized production losses (BOE)	Annualized industry output (revenue) losses (S000 1995)	Annualized industry output (revenue) losses (S000 1989) [c]	Annual Reduction in FTEs
Type 1 Losses [a]	--	--	--	--
Type 2 Losses	260,754	$5,736.6	$4,839.0	46
Type 3 Losses	--	--	--	6 to 9
Type 4 Losses [b]	--	$263.3	$222.1	2
Total Losses	260,754	$5,999.9	$5,061.1	54 to 57

[a] Type 1 losses are not calculated in this FEIA because any losses and gains are assumed to offset each other on the national level.
[b] Type 4 production losses are not calculated.
[c] Output values deflated from 1995 dollars to 1989 dollars because the Bureau of Economic Analysis regional employment multipliers use 1989 dollars.

Sources: EPA analyses described in text; Tables 10-16, 10-17, 10-18, and 10-19 in this FEIA.

TABLE 10-23

SUMMARY OF REGIONAL EMPLOYMENT AND OUTPUT LOSSES FOR THE LOUISIANA OPEN BAY DISCHARGERS AND THE TEXAS INDIVIDUAL PERMIT APPLICANTS UNDER THE SELECTED OPTIONS

	Annualized production losses (BOE)	Annualized industry output (revenue) losses ($000 1995)	Annualized industry output (revenue) losses ($000 1989) [c]	Annual Reduction in FTEs
Type 1 Losses [a]	--	--	--	--
Type 2 Losses	884,415	$19,457.1	$16,412.8	146
Type 3 Losses	--	--	--	17 to 39
Type 4 Losses [b]	--	$1,474.0	$1,243.4	11
Total Losses	884,415	$20,931.1	$17,656.2	174 to 196

[a] Type 1 losses are not calculated in this FEIA because any losses and gains are assumed to offset each other on the national level.
[b] Type 4 production losses are not calculated.
[c] Output values deflated from 1995 dollars to 1989 dollars because the Bureau of Economic Analysis regional employment multipliers use 1989 dollars.

Sources: EPA analyses described in text; Tables 10-16, 10-17, 10-18, 10-19, 10-21, and 10-22 in this FEIA.

TABLE 10-24

SUMMARY OF REGIONAL EMPLOYMENT AND OUTPUT LOSSES FOR THE GULF OF MEXICO UNDER THE SELECTED OPTIONS
(LOUISIANA OPEN BAY DISCHARGERS, TEXAS INDIVIDUAL PERMIT APPLICANTS, AND MAJOR PASS FACILITIES)

	Annualized production losses (BOE)	Annualized industry output (revenue) losses ($000 1995)	Annualized industry output (revenue) losses ($000 1989) [c]	Annual Reduction in FTEs
Type 1 Losses [a]	--	--	--	--
Type 2 Losses	1,186,358	$26,099.9	$22,016.3	194
Type 3 Losses	--	--	--	17 to 39
Type 4 Losses [b]	--	$2,144.5	$1,809.0	16
Total Losses	1,186,358	$28,244.4	$23,825.2	227 to 249

[a] Type 1 losses are not calculated in this FEIA because any losses and gains are assumed to offset each other on the national level.
[b] Type 4 production losses are not calculated.
[c] Output values deflated from 1995 dollars to 1989 dollars because the Bureau of Economic Analysis regional employment multipliers use 1989 dollars.

Sources: EPA analyses described in text; Tables 10-16, 10-17, 10-18, 10-19, 10-21, and 10-22 in this FEIA.

TABLE 10-25

SUMMARY OF REGIONAL EMPLOYMENT AND OUTPUT LOSSES FOR THE ALTERNATIVE REGULATORY BASELINE UNDER THE SELECTED OPTIONS

(MAJOR PASS FACILITIES, COOK INLET PLATFORMS, LOUISIANA OPEN BAY DISCHARGERS, AND TEXAS INDIVIDUAL PERMIT APPLICANTS)

	Annualized production losses (BOE)	Annualized industry output (revenue) losses ($000 1995)	Annualized industry output (revenue) losses ($000 1989) [c]	Annual Reduction in FTEs
Type 1 Losses [a]	--	--	--	--
Type 2 Losses	1,339,000	$29,458.0	$24,849.0	205
Type 3 Losses	--	--	--	17 to 39
Type 4 Losses [b]	--	$2,251.4	$1,899.1	17
Total Losses	1,339,000	$31,709.4	$26,748.1	239 to 261

[a] Type 1 losses are not calculated in this FEIA because any losses and gains are assumed to offset each other on the national level.
[b] Type 4 production losses are not calculated.
[c] Output values deflated from 1995 dollars to 1989 dollars because the Bureau of Economic Analysis regional employment multipliers use 1989 dollars.

Sources: EPA analyses described in text; Tables 10-16, 10-17, 10-18, 10-19, 10-21, and 10-22 in this FEIA.

10.5.2.2 Type 3 Regional Employment Losses

10.5.2.2.1 Primary Employment Losses

Baseline Losses

Independent of the Coastal Guidelines, 481 jobs are estimated to be lost among the Louisiana Open Bay and Texas Individual Permit operators (43 in Louisiana and 438 in Texas) as a result of baseline well shut-ins and firm failures. These job losses are associated with 37 baseline shut-in wells in Louisiana and 367 in Texas, as well as 12 baseline firm failures in Texas (zero in Louisiana).[43] A loss of 481 jobs represents a 34 percent reduction in existing employment within the Louisiana Open Bay and Texas Individual Permit groups (estimated at 699 FTEs in Louisiana and 699 FTEs in Texas[44]), without the Coastal Guidelines. Adjusted baseline employment is therefore 656 FTEs in the Louisiana Open Bay group and 261 FTEs in the Texas Individual Permit group, for a total of 917 FTEs. When Major Pass and Cook Inlet dischargers are counted (406 FTEs), total alternative baseline employment is 1,754 (1,313 in the Gulf and 431 in Cook Inlet).

Postcompliance Employment Losses

Under zero-discharge requirements, 47 wells among the Louisiana Open Bay dischargers and 47 wells among the Texas Individual Permit applicants, each with associated employment of 55 FTEs, are expected to shut in during the first year. As discussed in Chapter Seven, these 110 FTEs would have been baseline losses at some point in the near future because, on average, the wells that shut in in the first year postcompliance shut in in Year 5 in Texas and Year 11 in

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[43]job losses are associated with baseline well shut-ins. The firms that in baseline are very small firms with no employment (all labor is provided by contract). For each firm-failure, EPA assumes that only the owner becomes unemployed, for a total of 12 jobs lost. Employment lost due to well shut-ins is calculated on the basis of the estimated 1.16 FTEs needed to serve a well.

[44]These numbers capture only production employment. Other firm employment cannot be estimated for these operating segments.

Louisiana under the assumptions of the alternative baseline (without the Coastal Guidelines). The actual loss in FTEs under the alternative baseline is therefore the difference between the loss in FTEs in Year 1 and the loss in Year 5 or 11, which can be computed as

Loss in Year 1 - Present Value of Loss in Year 5 (Texas) or 11 (Louisiana)

under the assumption that earnings can be discounted and FTEs can be represented by these earnings. Thus, EPA estimates the present value Type 3 employment losses to be 29 FTEs in Louisiana and 16 FTEs in Texas. Annualized, these losses amount to 4 FTEs in Louisiana and 2 FTEs in Texas.

Additionally, as discussed in Section 10.4, a maximum of 0 to 3 firms in Texas and from 0 to one firm in Louisiana are expected to fail as a result of the Coastal Guidelines. These potentially failing firms are estimated to employ a total of 53 FTEs.[45] Annualizing these losses over 10 years, EPA estimates a maximum of 8 FTEs in annual direct losses in Louisiana and Texas due to firm failure. Total annual Type 3 losses, combining first-year shut-ins and firm failures, are 4 to 11 FTEs in Louisiana and 2 to 3 FTEs (with rounding) in Texas (see Tables 10-18 and 10-19). The respective reduction in employment is 0.6 to 1.7 percent of adjusted baseline employment (656 FTEs) for the Louisiana Open Bay dischargers and 0.8 to 1.1 percent of baseline employment (261 FTEs), among the Texas Individual Permit applicants, or at most, 1.1 percent of employment among the Louisiana Open Bay dischargers and the Texas Individual Permit applicants and at most 1.0 percent of alternative baseline employment among all Gulf operators[46] (1,313 FTEs), including Major Pass dischargers.

[41]The failing Texas firm actually reports 0 employees in the Section 308 Survey. This result can occur if production operations are handled by a contractor. EPA assumes that there is one owner who subsequently becomes unemployed for each of the three firms that are represented by this firm. The one Louisiana firm reports 50 nonproduction personnel.

[46]baseline FTE losses are accounted for.

10.5.2.2.2 Secondary Employment Losses

Based on the primary losses of 4 to 11 FTEs in Louisiana and 2 to 3 FTEs in Texas and using the regional (state) employment multipliers,[47] EPA estimates total (direct, indirect, and induced) Type 3 annual employment losses relative to the alternative baseline to be 11 to 30 FTEs in Louisiana and 6 to 9 FTEs in Texas (for a total of 17 to 39 FTEs in the Gulf), (see Chapter Seven of this FEIA and Tables 10-21 through 10-25 for summaries of regional Type 3 employment losses).

10.5.2.3 Total Regional Employment Losses Under the Assumptions of the Alternative Regulatory Baseline (Types 2, 3, and 4 Losses)

Based on primary and secondary losses due to first-year shut-ins and firm failures, production losses, and delayed investment, EPA estimates a local annual job loss of 120 to 139 FTEs for Louisiana Open Bay dischargers, and 54 to 57 FTEs associated with Texas Individual Permit applicants (see Tables 10-19 and 10-20 for a summary of these impacts). EPA estimates that when these losses are combined with Major Pass up to 249 FTEs will be lost per year in the Gulf coastal area and 12 FTEs will be lost per year in Cook Inlet as noted in Chapter Seven.

10.5.3 Community-Level Impacts

After summing all losses (Type 2, Type 3, and Type 4 losses) for each of the affected groups and using the maximum estimated employment loss,[48] EPA estimates that community-level impacts on the counties, parishes, and boroughs of concern are not significant, since, as discussed below, the unemployment rates in these areas do not change substantially.

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[47]for Louisiana and 3.0173 for Texas (RIMS II Handbook).

[48]These estimates overstate community losses, since the multipliers used to develop these estimates project losses in employment for the entire state of Louisiana, not just in the parishes of concern.

- Louisiana—A maximum of 139 FTEs will be lost in Louisiana annually (Open Bay dischargers only), and the current employment in the parishes in Louisiana[49] expected to bear the greatest impact is 619,158 employed persons (see Table 10-23).[50] EPA estimates that these losses represent a 0.02 percent change in employment in the affected areas of Louisiana, (unemployment rate changes from 6.23 percent to 6.25 percent). When impacts from the Major Pass dischargers are added to these losses, EPA estimates that a maximum of 192 FTEs will be lost in the same parishes of concern. These losses represent a 0.03 percent change in employment in the affected areas of Louisiana (unemployment rate changes from 6.23 percent to 6.26 percent).

- Texas—A maximum of 57 FTEs will be lost in Texas annually, and the current employment in the counties in Texas (see Table 10-26) expected to bear the greatest impact is 2,095,730 employed persons. EPA estimates that these losses represent a 0.003 percent change in employment in the affected areas of Texas, (unemployment rate changes from 6.425 percent to 6.427 percent).

- Gulf of Mexico—When impacts from Texas Individual Permit applicants and Louisiana Open Bay dischargers are added together, EPA estimates that a maximum of 196 FTEs will be lost in the same parishes and counties of concern annually. These losses represent a 0.007 percent change in employment in the affected counties and parishes of Louisiana and Texas, (unemployment rate changes from 6.38 percent to 6.39 percent). When impacts from the Major Pass dischargers are added to these losses, EPA estimates that a maximum of 249 FTEs will be lost annually in the Gulf area parishes and counties of concern. The total losses represent a 0.007 percent change in employment in the affected areas of Louisiana and Texas, (unemployment rate changes from 6.38 percent to 6.39 percent).

- Alaska—As noted in Chapter Seven, for Kenai Peninsula Borough, Alaska, EPA estimates that the employment losses in the affected area of Alaska leads to a 0.05 percent change in the unemployment rate in this area. While this is not a significant change, if EPA had selected Option #3 for produced water/TWC (zero discharge all, including Cook Inlet), the unemployment rate in this area would have changed by 0.6 percent (from 12.7 percent to 13.3 percent). EPA concludes that the impact of Option #3 to Kenai Peninsula Borough is significant. The Kenai would be disproportionately affected because the Peninsula is significantly dependent on oil and gas production, particularly when compared to the Gulf of Mexico area, where the coastal oil and gas industry is spread out over a large number of counties and parishes (see Chapter Seven).

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[49]Parishes included only if adjacent to Gulf of Mexico (including bays); includes the four parishes considered affected by Major Pass discharger impacts.

[50]Counties included only if adjacent to the Gulf of Mexico (including bays).

TABLE 10-26

EMPLOYMENT IN COUNTIES AND PARISHES POTENTIALLY AFFECTED UNDER THE ALTERNATIVE BASELINE ASSUMPTIONS

(1991)

	Civilian Labor Force	Unemployment Rate	Employed Population
Texas			
Cameron	109,146	12.5%	95,503
Willacy	6,963	15.7%	5,870
Kenedy	315	0.3%	314
Kleberg	14,669	6.4%	13,730
Nueces	139,626	7.7%	128,875
San Patricio	25,561	9.1%	23,235
Refugio	3,513	4.0%	3,372
Aransas	7,849	4.2%	7,519
Calhoun	9,900	5.7%	9,336
Jackson	5,517	4.6%	5,263
Matagorda	16,584	10.7%	14,810
Galveston	112,190	7.0%	104,337
Brazoria	93,541	5.6%	88,303
Harris	1,532,757	5.7%	1,445,390
Chambers	7,625	5.3%	7,221
Jefferson	114,796	6.7%	107,105
Orange	39,064	9.0%	35,548
Totals	**2,239,616**	**6.4% [a]**	**2,095,730**
Louisiana			
Cameron	4,284	5.5%	4,048
Vermillion	17,822	8.9%	16,236
Iberia	27,450	7.1%	25,501
St. Mary	25,033	8.1%	23,005
Terrebonne	38,921	6.9%	36,235
Lafourche	32,767	6.3%	30,703
St. Charles	19,277	6.5%	18,024
Jefferson	229,498	5.6%	216,646
Plaquemines	9,194	6.4%	8,606
St. Bernard	30,981	7.0%	28,812
Orleans	225,071	6.1%	211,342
Totals	**660,298**	**6.2% [a]**	**619,158**

[a] Weighted average.

Source: Bureau of Labor Statistics data, as reported by the U.S. Census Bureau at Internet address:
http://www.census.gov/datamap/www/index.html

Because of the Kenai Peninsula Borough's relative sensitivity and the Gulf's relative insensitivity to employment impacts on the local coastal oil and gas industry, EPA concludes that employment impacts (along with the results of analyses in Chapter Five) contribute to a finding of economic inachievability for zero discharge of produced water in Cook Inlet, but a finding of economic achievability for zero discharge of produced water in the Gulf of Mexico coastal area.

10.6 OTHER IMPACTS

EPA estimates that the Coastal Guidelines will have no significant effect on trade or inflation under the alternative baseline, for the same reasons that there were no impacts under the current regulatory baseline. NSPS impacts are not an issue among the Louisiana Open Bay and Texas Individual Permit groups, since these groups consist of specific operations that are currently discharging. Thus the impacts from NSPS requirements are the same as those discussed in Chapter Nine for the current regulatory baseline. Chapter Eleven presents the regulatory flexibility analysis for both baselines.

CHAPTER ELEVEN
REGULATORY FLEXIBILITY ANALYSIS

11.1 INTRODUCTION

The Regulatory Flexibility Act (RFA) was recently amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996, which has important implications for the implementation of rules that affect small business. The RFA requires the federal government to consider the impacts of proposed regulations on small entities (as defined in 13 CFR Part 121) during the rulemaking process. The RFA acknowledges that small entities have limited resources and makes the regulating federal agency responsible for avoiding burdening such entities unnecessarily.

The Administrator has certified that this rule will not have a significant effect on a substantial number of small entities and thus a Regulatory Flexibility Analysis is not required. Nevertheless, EPA has prepared a regulatory flexibility analysis equivalent to that required by the RFA as amended by SBREFA. Section 11.2 follows the steps of the Agency guidance as defined by the RFA to identify significant impacts on small firms and to determine whether a regulatory flexibility analysis should be presented. Section 11.3 presents a final regulatory flexibility analysis as required for a final rule.

11.2 INITIAL ASSESSMENT

The following subsections generally follow the steps of an initial assessment as current EPA guidance suggests.

11.2.1 Is the Rule Subject to Notice-and-Comment Rulemaking Requirements?

The Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category is subject to notice-and-comment rulemaking requirements.

11.2.2 Profile of Affected Entities

EPA prepared a profile of the regulated universe of entities in the PEIA (Chapter Three), which is supplemented in Chapter Three of this FEIA by the profile of the Major Pass dischargers. A total of 435 regulated entities (firms)[1] were estimated in the PEIA. An additional two entities (both Major Pass dischargers) were not surveyed and are added to this group for a total of 437 regulated entities (firms). The profiles distinguish characteristics of small entities versus large entities in the coastal oil and gas industry, where possible without compromising confidential business data.

11.2.3 Will the Rule Affect Small Entities?

The Small Business Administration (SBA) defines a small entity in the oil and gas industry as one with 500 or fewer employees. Based on this definition and Section 308 Survey data, as outlined in the PEIA and supplemented in the FEIA (see Chapter Three in both reports), EPA estimates that as of 1992, a total of 373 small firms would be potentially regulated by the Coastal Guidelines (approximately 85 percent of the coastal oil and gas industry, under both the current regulatory baseline and the alternative regulatory baseline). Most of these firms are currently subject to the rule's requirements (see below). Financial profiles of a sampling of these small firms are presented in Chapters Three and Ten, as well as in the PEIA (see PEIA,

[1]This figure does not include operators in some areas where zero discharge is being met by all firms, i.e., approximately 20 operators in California and the Gulf of Mexico outside Louisiana and Texas, who were not surveyed in the Section 308 Survey, and North Slope operators, who were surveyed but not analyzed in this FEIA.

Section 9.4). EPA has determined that the rule will affect some small coastal oil and gas firms under both baselines.

11.2.4 Will the Rule Have an Adverse Economic Impact on Small Entities?

EPA has determined that the majority of small entities regulated by the rule will incur no compliance costs, since they are already subject to zero discharge requirements. However, the Agency has identified, under the current regulatory baseline, three small firms in the Major Pass discharger group that will incur compliance costs as a result of the Coastal Guidelines. Under the alternative regulatory baseline,[2] the Agency has identified 59 small firms (56 plus the 3 small Major Pass discharging firms) that will incur compliance costs. Thus under both regulatory baselines, the Agency has identified some small firms that will be adversely (although not necessarily significantly) affected by the Coastal Guidelines.

11.2.5 Analysis of Significant Impact

Rather than conduct an Initial Assessment, EPA has performed a full regulatory flexibility analysis.

11.3 REGULATORY FLEXIBILITY ANALYSIS

Section 604 of the RFA requires that a final regulatory flexibility analysis (FRFA) accompanying a final rule must:

- state the need for and objectives of the rule.

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[2]For Texas Individual Permit Applicants and Louisiana Open Bay dischargers, EPA assumes under the alternative regulatory baseline that the facilities operated by these groups now subject to zero discharge would be able to obtain authorization to continue discharging unless prohibited by the Coastal Guidelines, although EPA believes this is unlikely.

- summarize the significant issues raised by public comments on the initial regulatory flexibility analysis (IRFA) and the Agency's assessment of those issues, and describe any changes in the rule resulting from public comments.

- describe the steps the agency has taken to minimize the significant economic impact on small entities consistent with the stated objectives of the applicable statutes, including a statement of the factual, policy, and legal reasons for selecting the alternative adopted in the final rule and why each one of the other significant regulatory alternatives to the rule considered by the Agency which affect the impact on small entities was rejected.

- describe/estimate the number of small entities to which the rule will apply or explain why no such estimate is available.

- describe the projected reporting, recordkeeping, and other compliance requirements of the rule, including an estimate of the classes of small entities that will be subject to the requirements of the rule.

The following sections address these issues.

11.3.1 Need for and Objectives of the Rule

This rule is being promulgated under the authority of Sections 301, 304, 306, 307, 308, and 501 of the Clean Water Act, 33 U.S.C. Sections 1311, 1314, 1316, 1317, 1318, and 1361. Under these sections, EPA is setting Effluent Limitations Guidelines and Standards for the control of discharge of pollutants for the coastal subcategory of the Oil and Gas Extraction Point Source category. The regulations also are being proposed pursuant to a Consent Decree entered in *NRDC et al. v. Reilly* (D.D.C. No. 89-2980, January 31, 1992), and are consistent with EPA's latest Effluent Guidelines Plan under Section 304(m) of the CWA (see 61 FR 52582, October 7, 1996).

The objective of the CWA is to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters." To assist in achieving this objective, EPA issues effluent limitations guidelines, pretreatment standards, and new source performance standards for industrial dischargers. Sections 301(b)(1) and 304(b)(1) authorize EPA to issue BPT effluent limitations guidelines. The existing effluent limitations guidelines, which were issued on April 13, 1979 (44 FR 22069), are based on the achievement of BPT for control of conventional pollutants. Section 304(b)(4) authorizes EPA to issue BCT guidelines for conventional pollutants; Sections 301(b)(2)(E) and 304(b)(2) authorize EPA to issue BAT guidelines to control nonconventional and toxic pollutants; Section 306 authorizes EPA to issue NSPS for all pollutants; and Sections 304(g) and 307(b) authorize EPA to issue PSES and PSNS for all pollutants.

11.3.2 Summary of Impacts on Small Businesses as a Result of the Effluent Guidelines

Effluent limitations guidelines and standards are not directly implemented, but form the "floor" for NPDES permit writers in issuing effluent limitations in permits. Thus, the requirements of this rule will be implemented through NPDES permits issued by the state (if it has NPDES permit authority) or EPA. The Clean Water Act section 301 requires that no discharge may take place without a permit; this rule does not affect the requirement to apply for and obtain a permit.

The overwhelming majority of entities covered by this rule are already subject to NPDES permits requiring zero discharge. This rule will have no impact on entities already subject to zero discharge in NPDES permits. However, dischargers into the major passes of the Mississippi that do not yet have an NPDES permit will need to either send their produced water to a facility for commercial injection or inject onsite. Injection would require a Class II Underground Injection Control Permit pursuant to the Safe Drinking Water Act, 42 U.S.C. 300f *et seq.*; 40 C.F.R. Part 144. The type of skills that would be required for such a permit application are similar to those that are required for an NPDES application. Furthermore, the applicant would need to have an understanding of the oil and gas facility's operations (e.g., current and projected volume of produced water), and the technical requirements for Class II injection wells (e.g., well siting and UIC permitting requirements, which involve an understanding of well integrity issues). These skills are a part of or are transferable from skills necessary to produce oil and gas at existing operations. Many of the operators use injection of produced water for waterflooding or for disposal at other production locations.[3] Some recordkeeping and reporting requirements will

[3]Major Pass Dischargers Data Submittals (CBI data; in rulemaking record).

be reduced because if firms meet zero discharge, they will no longer be required to obtain an NPDES permit or to keep monitoring reports to show that they are meeting discharge limitations.

Current Regulatory Baseline

As described in Chapter Six of this FEIA, EPA has determined that under the current regulatory baseline, three small firms will be adversely affected by the Coastal Guidelines (i.e., they are expected to incur compliance costs). As discussed in Chapter Six, however, on the basis of cash flow analysis, both for the first year and over a 10-year period, EPA determined that none of these firms would be likely to fail, and in fact, that the impact of pollution control costs on cash flow is relatively small.[4] EPA also determined that the capital-raising ability of the small firms that provided financial data was sufficient to meet the requirements of the Effluent Guidelines. The small firm that did not provide financial data reported to EPA that compliance costs of this rule would not materially affect the company's finances.[5] Furthermore, all three firms are not substantially different from the numerous other small firms in the coastal region that currently or will soon inject produced water (see Chapters Three and Ten).

Also of concern in this regulatory flexibility analysis is the impact of the Coastal Guidelines on small communities. Although the rule does not regulate small communities, it may indirectly affect small communities due to decreased royalties recieved by the state or local government. Some of the losses in royalties may have an impact on the parishes of concern in Louisiana under the current regulatory baseline (Cook Inlet platforms are in state waters, thus impacts on boroughs are not an issue). Most of the royalty owners affected by losses in the Major Passes are federal and state government, since the majority of production is in offshore waters. However, EPA does not know exactly how royalties might be distributed to local governments. EPA assumes for this analysis, that 50 percent of royalty losses will affect the four

[4]Cash Flow Analysis of Major Pass Dischargers (CBI data; in rulemaking record). Exact results not reported to protect business confidentiality.

[5]Major Pass Dischargers Data Submittals (CBI data; in rulemaking record).

parishes in Louisiana in coastal subcategory areas (Jefferson, population 457,738; Plaquemines (population 25,877; St. Bernard, population 67,002; and Orleans, population 489,595).[6] Assuming 50 percent of royalty losses will affect these parishes is highly conservative given that the majority of Major Pass discharger production is from state and federal offshore waters.[7] Since the SBA defines small community as having a population of 50,000 or less, only Plaquemines Parish is considered a small community.

The total royalty loss associated with Major Pass dischargers is $6.5 million over the approximately 10-year life of these operations, which is only 0.8 percent of total royalties generated by these operations (see Table 5-5). Annualized, this loss is $0.9 million per year. EPA distributed 50 percent of this loss ($0.5 million) on the basis of population, yielding a loss of $0.44 per person in the four parishes. EPA thus estimated that Plaquemines Parish might lose $11,437 annually as a result of Coastal Guidelines. On a per person basis, the $0.44 per person loss is 0.004 percent of the parish's per capita income of $11,262.[8] EPA guidance for performing regulatory flexibility analyses on communities suggests the use of the regulatory cost to the community as a percentage of per capita income in the affected community as a measure of the significance of impact on the community. Note that even if 100 percent of the royalty losses affected the parishes of concern, the impacts would be very small. EPA thus concludes that the impact on the parish is negligible.

Alternative Regulatory Baseline

Including the three small firms in the current regulatory baseline, EPA's alternative regulatory baseline includes a total of 59 small firms that are expected to incur compliance costs as a result of achieving zero discharge of produced water, or 16 percent of 371 total small firms

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[6]Bureau of Labor Statistics data (1992 data, as reported by the U.S. Census Bureau at Internet Address: http://blue.census.gov/datamap/www/index.html).

[7]Major Pass Dischargers Data Submittals (CBI data; in CBI rulemaking record).

[8]Bureau of Labor Statistics data (1989 data inflated to 1995, as reported by the U.S. Census Bureau at Internet Address: http://blue.census.gov/datamap/www/index.html).

estimated to be operating coastal subcategory wells in the Gulf Coastal area. The small firms that may incur compliance costs under the alternative regulatory baseline are similar to, and may actually be better off financially than, the entire regulated coastal universe of small firms (see Chapter Ten).

Tables 10-12 and 10-13 in Chapter Ten present the results of analyses using a benchmark of a 5 percent change in working capital and equity to identify potentially significantly affected firms. A total of 12 out of 22 firms for which EPA had received financial information in the Section 308 Survey (estimated to represent approximately 28 of the 56 firms, or 50 percent) had changes in both working capital and equity of more than 5 percent (or were estimated to have a less than 5 percent change in equity but reported negative working capital, or were estimated to have a very large change in working capital).

Upon further investigation, however, EPA found that most (10) of these firms either would fail in baseline, would plug and abandon their coastal operations in the baseline because of negative earnings among those operations, would plug and abandon or sell their operations because of the very small contribution the operations made to their overall earnings, or would meet zero discharge requirements but show adequate returns on assets and equity (see Table 10-13 in Chapter Ten).

EPA identified two firms that might or might not face sizeable impacts (see Table 10-12 in Chapter Ten of this FEIA). Due to lack of information, however, it is impossible for EPA to determine the magnitude of the impacts because EPA believes these firms might be the operators, not the owners, of the wells in question. Thus their revenues might not reflect the revenues of the affected production facilities and these firms might not bear the costs of pollution control. To be conservative, EPA assumes these two firms would be severely affected (i.e., they would fail) because there is no information to indicate the contrary. Additionally, no other firms among those analyzed under the current regulatory baseline are expected to fail even with the additional produced water cost for a Major Pass discharger under the assumptions of the alternative baseline (costs are approximately 20 percent higher for this discharger under the alternative regulatory baseline). EPA estimates that the two firms identified as possible firm failures represent 4 out of the 59 small firms estimated to be affected by compliance costs (7 percent of these firms) in the alternative baseline. The actual impact of the regulation must be measured against the total number of small firms that are regulated by the Coastal Guidelines but that are meeting the requirements of the rule. EPA estimates that 356 small firms will be regulated by the Coastal Guidelines once baseline firm failures are accounted for.[9] Thus the Coastal Guidelines will have a substantial effect on only 1 percent (four firms) out of all regulated small firms. EPA considers the difference between 0 percent of large firms and 1 percent of small firms experiencing substantial impacts to be small, given that 85 percent of all firms in the Gulf coastal region are estimated to be small (see Section 11.2.3 above). The Agency concludes that the rule does not disproportionately affect small firms.

The skills needed to meet the requirements of the Coastal Guidelines are the same as those discussed above for Major Pass operators. Again, many of the operators have direct experience with similar operations (such as waterflooding or injection for disposal at other locations) since most of them also operate onshore wells.[10] Recordkeeping skills would be similar to those required for NPDES permitting and some recordkeeping requirements would be reduced since monitoring reports would not be required under zero discharge.

EPA also considered impacts on small communities (counties and parishes) in Texas and Louisiana resulting from losses in royalties. As in the current regulatory baseline, EPA assumed that the counties and parishes of concern (see Table 11-1) would lose 50 percent of the annualized royalty losses attributed to the Coastal Guidelines although this percentage is high, since the states and individuals are also royalty owners in these areas (actual royalties may be in the 5- to 10-percent range, although EPA does not know the exact percentage of royalties that might be received by local governments). EPA used the same method as under the current regulatory baseline, distributing the annualized losses by population in the affected counties and parishes. As Table 11-1 shows, the loss per person in Texas counties of concern is \$0.12, given an annualized loss of \$0.5 million (which is associated with a 6.2 percent loss of total royalties

[9]In the PEIA (Chapter Nine), EPA estimated that out of an estimated 371 small firms, 354 small firms would be regulated post-baseline based on the Section 308 Survey results and after the results of baseline closures were considered. Added to this are two of the three Major Pass small firms not in the Survey universe, for a total of 356 small firms.

[10]Section 308 Survey Questionnaires (CBI data; in rulemaking record).

generated by the Texas Individual Permit Applicants; see Table 10-5). Out of the 9 small counties, the greatest impact is in Willacy County, where the per capita income is $7,201; royalty losses on a per-person basis are 0.002 percent of per capita income in this county. Again, royalties lost as a percentage of per capita income is used as a measure of impact as suggested by recent EPA guidance.

In Louisiana, the greatest impacts are associated with the four parishes assumed affected by impacts on Major Pass dischargers (which are associated with royalty losses of $6.5 million over the life of the project or 0.8 percent of all royalties as generated; see Table 10-7), since these four parishes are also assumed to be affected by impacts on Louisiana Open Bay dischargers (which are associated with royalty losses of $17.7 million over the life of the project or 10.2 percent of total royalties generated; see Table 10-5). The only small community in this group is Plaquemines Parish, which EPA estimates will be affected by an estimated $33,754 loss in royalty payments per year (see Table 11-1), or $1.30 per person in the parish ($0.44 of which is attributable to impacts on Major Pass dischargers and $0.86, to impacts on Open Bay dischargers). This per-capita loss is 0.012 percent of income in the parish. The other two counties in the affected areas of Louisiana considered small in this analysis are estimated to experience losses in royalties totaling $7,870 in Cameron Parish ($0.86 per capita or 0.007 percent of income) and $38,268 in St. Charles Parish ($0.86 per capita or 0.006 percent of income). Note that even if 100 percent of the royalties were lost by the affected counties and parishes, impacts would still be very small.

EPA concludes that impacts on small counties and parishes in Texas and Louisiana under the assumptions of the alternative baseline are negligible.

11.3.3 Issues Addressed in Public Comments and EPA's Responses

EPA received comments that the rule should not require firms discharging produced water to open bays in Louisiana (assuming the state changes its law requiring zero discharge) and firms in Texas (predominately small firms) that had applied for individual permits to meet zero discharge requirements because the economic impact might be severe for these small firms.

TABLE 11-1

IMPACT ON COUNTIES AND PARISHES POTENTIALLY AFFECTED UNDER THE ALTERNATIVE BASELINE ASSUMPTIONS

	Total Population [a]	Per Capita Income [b]	Cost per County	Cost per Person	Cost as % of Per Capita Income
Texas					
Cameron	278,687	$8,447	$32,698	$0.12	0.001%
Willacy	18,278	$7,201	$2,145	$0.12	0.002%
Kenedy	439	$10,921	$52	$0.12	0.001%
Kleberg	30,377	$11,357	$3,564	$0.12	0.001%
Nueces	300,815	$13,510	$35,295	$0.12	0.001%
San Patricio	60,600	$11,173	$7,110	$0.12	0.001%
Refugio	7,839	$12,443	$920	$0.12	0.001%
Aransas	19,188	$13,507	$2,251	$0.12	0.001%
Calhoun	20,106	$12,298	$2,359	$0.12	0.001%
Jackson	12,937	$12,122	$1,518	$0.12	0.001%
Matagorda	37,946	$13,484	$4,452	$0.12	0.001%
Galveston	203,857	$16,588	$23,919	$0.12	0.001%
Brazoria	2,971,755	$15,966	$348,678	$0.12	0.001%
Harris	228,084	$18,022	$26,761	$0.12	0.001%
Chambers	20,543	$14,484	$2,410	$0.12	0.001%
Jefferson	243,257	$14,638	$28,541	$0.12	0.001%
Orange	83,080	$13,625	$9,748	$0.12	0.001%
Totals	**4,537,788**		**$532,421**		
Louisiana					
Cameron	9,125	$12,553	$7,870	$0.86	0.007%
Vermillion	50,326	$10,375	$43,403	$0.86	0.008%
Iberia	69,631	$11,222	$60,053	$0.86	0.008%
St. Mary	58,018	$10,405	$50,037	$0.86	0.008%
Terrebonne	99,796	$11,268	$86,069	$0.86	0.008%
Lafourche	86,723	$10,966	$74,794	$0.86	0.008%
St. Charles	44,372	$14,108	$38,268	$0.86	0.006%
Jefferson	457,738	$15,228	$550,389	$1.20	0.008%
Plaquemines	25,877	$11,262	$31,115	$1.20	0.011%
St. Bernard	67,002	$12,462	$80,564	$1.20	0.010%
Orleans	489,595	$13,481	$588,694	$1.20	0.009%
Totals	**1,458,203**		**$1,611,256**		

[a] 1992 data.
[b] 1989 data inflated to 1995.

Source: Bureau of Labor Statistics data, as reported by the U.S. Census Bureau at Internet address: http://blue.census.gov/datamap/www/index.html

10/30/96COUNTEMP.WK4

These comments have been addressed in detail in Chapter Ten of this FEIA, in the Comment/Response Document,[11] and in the discussion in Section 11.3.2 regarding effects on firms under the alternative baseline assumptions. EPA thoroughly investigated the possibility that 56 additional small firms might be adversely affected by the Coastal Guidelines. As part of this investigation, EPA has undertaken a detailed financial analysis of the small firms for which it obtained financial data. A summary of the results of this analysis are presented above in Section 11.3.2, in Section Ten of this FEIA, and in the Comment/Response Document for the Final Rule and the record for this rule.

EPA also received comments from one small Major Pass discharger that presented its own assessment of impact. EPA carefully reviewed all the data received from the firm, which showed the firm to be financially healthy and growing prodigiously. Even the results of several sensitivity analyses using substantially higher compliance costs than EPA anticipates the firm will actually experience showed no major impacts on production.[12] While acknowledging that the firm will experience impacts, possibly in the form of slower growth, EPA does not expect the impacts to be of a magnitude to cause firm failure.

Finally, EPA received a comment noting that small firms might have difficulty raising the necessary capital to meet zero discharge requirements. EPA has analyzed cash flow and returns, and where data were available, credit lines and capital expenditure budgets, all of which are methods used to judge whether the firms in question are likely to be able to raise the capital they need to meet zero discharge requirements (see Chapters Six and Ten of this FEIA). Where EPA was uncertain whether a firm could raise the capital needed, it estimated a firm failure.

Thus, none of these comments changed EPA's conclusions that the Coastal Guidelines will not have a significant impact on a substantial number of small firms: significant impacts are

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[11]U.S. EPA Responses to Public Comments on the Effluent Limitations Guidelines and New Source Performance Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category, October 1996.

[12]Compliance Cost Sensitivity Analysis of a Major Pass Discharger (CBI data; in rulemaking record).

limited to 1 percent of small firms subject to the Coastal Guidelines, and nearly all small firms should be able to raise the necessary capital to comply with the rule.

11.3.4 Significant Alternatives to the Rule

EPA's selected option for produced water/TWC (Option #2), which requires all coastal firms, aside from those in Cook Inlet, to meet zero discharge from their coastal oil and gas operations was selected because it is technologically available, economically achievable, and has acceptable nonwater quality environmental impacts.

As stated in the Preamble to the rule, this rule generally codifies in the Code of Federal Regulations existing permit requirements that have been developed on a "Best Professional Judgment Basis" under Section 402(a)(1) of the Clean Water Act. These permits have generally already established zero discharge for drilling fluids and drill cuttings and for produced water, except for certain dischargers to the major passes of the Mississippi. Under Sections 304 and 307 of the Clean Water Act, EPA is to consider a number of factors in establishing effluent limitations guidelines and standards, including whether the requirements are technologically and economically achievable and whether they have acceptable nonwater quality environmental impacts. EPA has found that zero discharge meets these criteria for those facilities that are currently subject to zero discharge permits and for those facilities that currently do not have an NPDES permit. As discussed in the Preamble and the Development Document for the rule considering information in the rulemaking record indicating technological and economic achievability and acceptable nonwater quality environmental impacts, along with the evidence in the record showing that many similarly situated facilities are already achieving zero discharge, EPA did not believe that an alternative allowing discharge in the Gulf of Mexico would provide a level playing field among dischargers and nondischargers or meet the objectives of the Clean Water Act.

Because EPA is aware that numerous operators in Texas have applied for individual permits authorizing discharge of produced water, and that the DOE has questioned whether discharges to Louisiana open bays should continue to be allowed (despite state law prohibiting this discharge beyond January 1997), EPA undertook a very detailed review of the economic impacts on these facilities under the assumption that the state law could change and that individual permits would be granted despite the general permits prohibiting discharge. This analysis indicates that the firms that are or will be achieving zero discharge are not substantially different than the discharging firms EPA analyzed under either the regulatory or the alternative baselines, and, in fact, the small Louisiana Open Bay and Texas Individual Permit Applicant dischargers might be slightly stronger financially than the small Section 308 Survey operators as a whole (see Chapter Ten). EPA does not believe it should take any actions that would enable a select few small firms associated with Major Pass, Texas Individual Permit Applicants, or Louisiana Open Bay dischargers to achieve a competitive advantage over these other, nondischarging small firms in the region that are complying with federal law.

Having considered these impacts under the alternative baseline and finding that zero discharge is technically and economically achievable for these dischargers, with acceptable nonwater quality environmental impacts, along with evidence showing that many similarly situated facilities are already achieving zero discharge, EPA does not believe that an alternative allowing discharge in the Gulf of Mexico would provide a level playing field among dischargers and nondischargers or meet the objectives of the Clean Water Act.

APPENDIX A

ECONOMIC ASSUMPTIONS USED IN THE PRODUCTION LOSS MODEL

EPA based the economic and financial accounting assumptions used in the economic model on common oil industry financing methods and procedures.[1,2,3] Tax computations in the model reflect the Tax Reform Act of 1986 (Public Law 99-514).

A.1 MODEL PARAMETERS

A.1.1 Corporate Income Tax Rates

EPA assumes that the projects analyzed using the production loss model are incremental to the other activities of the company and that the company has at least $100,000 of net income in addition to the projects being analyzed. Therefore, the taxable net income from these projects is marginally taxed at the federal corporate rate of 34 percent.[4] In addition, EPA assumes that any net losses in the initial years of a project (before production comes on line) can be applied to reduce the taxable income of other projects owned by the same operator, so that an effective tax shield of 34 percent of the loss is realized. In other words, the yearly net cash outflow under such circumstances is 100 percent minus 34 percent, or 66 percent of the year's loss. These assumptions are appropriate given the customary size and level of

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[1]Johnston, Daniel. 1992. Oil Company Financial Analysis in Nontechnical Language. PennWell Publishing, Tulsa, OK.

[2]Research Institute of America. 1995. The Complete Internal Revenue Code. Research Institute of America, New York, NY.

[3]Houghton, James L. 1987. Arthur Young's Oil and Gas Federal Income Taxation. Commerce Clearing House, Inc., Tulsa, OK.

[4]A handful of Major Pass operators indicated that they were subject to a corporate tax rate of 35 percent. This is the marginal tax rate applied to corporations with taxable income exceeding $10 million. In these cases, EPA used the rate reported by the operator (Major Pass Dischargers Data Submittals [CBI data; in rulemaking record]).

activities of firms undertaking oil exploration and production. The basis for federal income is gross revenues minus royalty payments, severance taxes, depletion and depreciation allowances, expensed capital investments, state income taxes, and operating costs.

Operators in Louisiana state waters (i.e., the Major Pass and Louisiana Open Bay dischargers) are subject to state, as well as federal, corporate income taxes. The marginal state income tax rate for these operators is 8 percent, which assumes that they have over $200,000 in net income from their combined enterprises.[5] State income taxes, and the state income tax shield generated by any net losses during the initial years of the project, are treated in the model in the same manner as federal income taxes. Income taxes paid to states are subtracted from net taxable income to calculate the basis for federal income tax.

A.1.2 Severance Taxes

Operations located in state waters are subject to state severance taxes. Texas state severance tax rates are 4.6 percent on oil and 7.45 percent on gas. Louisiana imposes severance taxes of 12.5 percent on oil and $0.07 per Mcf on gas.[6] Some Major Pass operators reported severance tax rates less than the standard ones for Louisiana because they are eligible for various exemptions and tax abatement programs.[7] EPA used the rate reported by the operators in analyzing these projects.

The Alaska severance tax structure consists of nominal rates that are then adjusted downward to effective tax rates on the basis of a ratio referred to as the Economic Limit Factor (ELF). The nominal tax rates on oil are 12.25 percent of gross revenues for the first 5 years of production and 15 percent thereafter. The nominal tax rate on gas is 10 percent. The ELF varies depending on field size, well productivity, and whether oil or gas is being produced.[8]

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[5]Commerce Clearing House, Inc. 1994. State Tax Handbook. Commerce Clearing House, Inc., Tulsa, OK.

[6]Ibid.

[7]Major Pass Dischargers Data Submittals (CBI data; in rulemaking record).

[8]Logsdon, Charles. 1996. Personal communication between Charles Logsdon, Alaska Department of Revenue, and Cathy Scholz, ERG, dated August 14, 1996, regarding oil and gas taxes in Alaska.

For oil, the ELF is applied only if it is positive. The oil ELF formula is:

$$ELF = 1 - \left(\frac{300}{PPW}\right)^{\left(\frac{150000}{AD}\right)^{1.5333}}$$

where

PPW = Average oil production per well per day in the field

AD = Average daily production from the field

For the first five years of production: Oil Severance Taxes = Gross revenues x 12.25% x ELF

After the first five years of production: Oil Severance Taxes = Gross Revenues x 15% x ELF

The oil ELF used to be subject to negotiation between the oil company and the Alaska Department of Revenues. Now, the formula used to calculate the ELF simply shelters small fields from paying severance taxes. If a field produces less than 300 barrels per day (bpd) per well, the ELF reaches zero. Furthermore, a new oil field would need to pay tax only if it has 100 million barrels in reserves and produces 50,000 bpd when it comes on line. EPA's contact at the Alaska Department of Revenue reported that, given these shelters, fields in Cook Inlet have not paid oil severance taxes for several years.[9]

Although the Cook Inlet operators do not pay oil severance tax, they are subject to a production tax surcharge of $0.05 per barrel. Revenues from this tax are allocated to the Hazardous Release Fund, which is devoted to environmental clean-up efforts. The economic model for the oil-producing Cook Inlet platforms therefore includes only a $0.05 per barrel levy; neither the severance tax nor the oil ELF are applied.

[9]Logsdon, Charles. 1996. Personal communication between Charles Logsdon, Alaska Department of Revenue, and Cathy Scholz, ERG, dated August 14, 1996, regarding oil and gas taxes in Alaska.

The ELF for gas differs slightly from that for oil. It does not shelter small fields from paying taxes and, as a result, gas producers in Cook Inlet, Alaska, do pay severance taxes. The ELF formula for gas is as follows:

$$ELF = 1 - \frac{3000}{PPW}$$

where

PPW = Average gas production per well per day in the field

Gas severance taxes are calculated as follows:

$$\text{Gas Severance Taxes} = \text{Gross Revenues} \times 10.00\% \times \text{ELF}$$

The gas ELF is also applied as long as it is positive.[10]

The basis for severance tax calculations in Louisiana, Texas, and Alaska is gross revenues minus exempt revenues, where royalty payments to state governments are considered exempt revenues.

A.1.3 Royalty Rates

Operators of oil- and gas-producing properties are usually required to pay production royalties to the lessors or owners of the land. Lessors and owners include the federal government for OCS leases, state governments for leases located in state waters, and the state and private owners for leases on land.

In many instances, the royalty rate is a floating rate that varies from year to year, based on a complex calculation keyed to the amount or mix of production. For the projects modeled, EPA assumed that an average fixed rate based on the owning company's data yields the best approximation of royalty payments. The Agency calculated the value of royalty payments for Cook Inlet platforms and Major Pass

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[10]Logsdon, Charles. 1996. Personal communication between Charles Logsdon, Alaska Department of Revenue, and Cathy Scholz, ERG, dated August 14, 1996, regarding oil and gas taxes in Alaska.

dischargers using owner-supplied information on average royalty rates and estimates of the value of annual production generated by the model.[11,12] Royalty rates for the Louisiana Open Bay and Texas Individual Permit wells were obtained through the Section 308 Survey. For wells that did not report royalty rates, EPA substituted the average reported rate among the Louisiana Open Bay dischargers and Texas Individual Permit applicants.

A.1.4 Depreciation

The Tax Reform Act of 1986 modified the Accelerated Cost Recovery System (ACRS) for property placed in service after December 31, 1986. Under the modified system, most oil and gas equipment is classified as 7-year property. The recovery method for this class is the double declining balance.[13] The schedule used to write off capitalized costs in the model is as follows:

Year 1	14.29% of costs
Year 2	24.49% of costs
Year 3	17.49% of costs
Year 4	12.49% of costs
Year 5	8.93% of costs
Year 6	8.92% of costs
Year 7	8.93% of costs
Year 8	4.46% of costs

EPA defines year 1 in the above table as the first year in which the equipment is placed in service. According to the relevant accounting principles, this is the first year in which the equipment produces oil or gas.

[11]Major Pass Dischargers Data Submittals (CBI data; in rulemaking record).

[12]Section 308 Survey data.

[13]Snook, S.B., and W.J. Magnuson, Jr. 1986. The Tax Reform Act's Hidden Impact on Oil and Gas. The Adviser. December, pp. 777-783.

The value of the deduction for depreciation is reduced by inflation. To maintain the constant-dollar basis of model calculations, EPA adjusted the value of the depreciation deduction downwards in later years by the inflation rate.

A.1.4.1 Basis for Depreciation

The Tax Reform Act of 1986 repealed the Investment Tax Credit.[14,15] This means that the initial basis for depreciation is 100 percent of the total capitalized costs.

A.1.5 Oil Depletion Allowance

The Internal Revenue Code allows oil and gas operators to take a deduction from income for depletion of oil and gas properties. The depletion of wasting assets such as mineral resources is analogous to depreciation of fixed assets, except that it is based directly on the removal or sale of a portion of total recoverable reserves (i.e., the asset is reduced directly, rather than through accumulation over several years, as is done in depreciation of fixed assets).

In the case of resources removed from a leased property, depletion must be apportioned between the lessor and the lessee. For oil and gas operators, the operator's share of the total allowable depletion is equal to 1 minus the royalty rate.

The oil depletion allowance may be calculated on either a cost basis or a percentage basis. Integrated (major) oil and gas producers are only entitled to a depletion allowance calculated on a cost basis, but independents are entitled to the higher of either cost or percentage depletion. A flag in the EPA model identifies major and independent operators and determines how depletion will be calculated.

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[14]Snook, S.B., and W.J. Magnuson, Jr. 1986. The Tax Reform Act's Hidden Impact on Oil and Gas. The Adviser. December, pp. 777-783.

[15]Coopers and Lybrand. 1986. Tax Reform Act of 1986: Analysis. New York, NY.

A.1.5.1 Depletion—Cost Basis

Cost depletion is based on units of production and is used to recover leasehold expenses over the producing lifetime of the well. As noted above, majors are required to calculate depletion on a cost basis, but independents may choose between cost- and percentage-basis depletion, depending on which value is higher.

The formula for cost depletion is as follows:

$$\text{Total annual depletion} = (C - D - S) * \left(\frac{P}{R}\right)$$

where:

C = Leasehold costs (bonus bid and geological and geophysical expenses)
D = Accumulated depreciation taken in prior years
S = Salvage value of equipment
P = Barrels of oil produced during the year
R = Recoverable reserves remaining at the beginning of the year (includes P)

Salvage amounts (S) are not subtracted in the EPA model because it is assumed that the after-tax cost of removing the infrastructure and retiring the well at the end of its economic life is approximately equal to its salvage value and that the salvage value, therefore, has no impact, positive or negative, on cash flow.

The initial basis for calculating cost depletion in EPA's model consists of the bonus bid and the geological and geophysical expenses. This basis is adjusted downwards to account for 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 total recoverable units at the start of the period. For simplicity, EPA assumes that all units produced in a period are sold in the same period.

The value of cost basis depletion is reduced in later years by inflation. Thus, the value used by EPA in calculating annual cash flow is an inflation-adjusted value. The nonadjusted value is used to calculate the basis for depletion in subsequent years.

Currently, EPA's model commences during the productive phase of the oil and gas projects being analyzed. Consequently, the leasehold costs are considered sunk costs and will generally be zero; these costs would be incurred *prior* to the productive phase of the project. If leasehold costs are zero, cost depletion will also be zero. EPA's assumption that cost depletion is zero will tend to cause an underestimation of earnings and, therefore, an underestimation of the productivity of the projects calculating depletion on a cost-basis. Only integrated (major) oil and gas operators, who must use cost depletion, are affected by the omission of the depletion allowance. In consequence, all Cook Inlet operators and some Gulf of Mexico operators have $0 annual depletion. The underestimation of productivity for these operators is offset, however, by the fact that the sunk costs themselves are not factored into the analysis.

A.1.5.2 Depletion—Percentage Basis

Percentage depletion is based on revenues from oil and gas, net of oil and gas royalties. Sections 613 and 613a of the Internal Revenue Code contain the rules for percentage depletion.

Only independent operators are permitted to calculate depletion on a percentage basis. The depletion rate for these operators is 15 percent of gross income (excluding rents or royalties) from each leased property. The Cook Inlet/Major Pass model calculates percentage depletion amounts for each operator's individual leases and sums these amounts to develop a figure for each operator's total depletion. The Louisiana Open Bay/Texas Individual Permit model assumes that each well is a separate lease.

A maximum number of barrels of oil or Mcf of gas can be depleted at the full 15 percent per lease per day in a given year. This is referred to as the "depletable quantity." Currently, the depletable quantity is 1,000 bbls of oil or 6,000 Mcf gas production per lease per day. For simplicity, EPA converts Mcf gas into BOE and then calculates depletion based on the 1,000 bbl limit.

When production on a given lease is less than or equal to the depletable quantity of 1,000 BOE per day, depletion is calculated as follows:

$$\text{Depletion} = (\text{Gross Oil and Gas Revenues} - \text{Oil and Gas Royalties}) \times 0.15$$

When production on a given lease exceeds the depletable quantity of 1,000 BOE per day, the following formula is used:

$$\text{Depletion} = (\text{Gross Oil and Gas Revenues} - \text{Oil and Gas Royalties}) \times 0.15 \times \left(\frac{1000}{\text{BOEPD}}\right)$$

Depletion is adjusted by the ratio of the depletable quantity (1,000 BOE) to actual production.

The maximum allowable percentage depletion deduction is 65 percent of the operator's total taxable income for the year before depletion. Any depletion amount disallowed on this basis may be carried over and applied in the subsequent year, subject to the same 65 percent limitation.

A.1.6 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. EPA calculates a value for "adjusted depreciation" as follows:

$$\begin{array}{c}\text{Adjusted depreciation}\\ \text{in year X}\end{array} = \frac{\text{Depreciation in year X}}{(1 + \text{inflation rate})^{\text{Year X}}}$$

An "adjusted cost-basis-depletion" value is calculated in a similar manner.

The inflation rate of 3 percent is the average rate for inflation over the past several years.[16]

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[16]Statistical Abstract of the United States (average from 1992 to 1995).

A.1.7 Discount Rate

The discount rate used in this analysis represents the opportunity cost of capital for investments in oil and gas production.

For Cook Inlet, EPA discounts annual project cash flows to the present using an 8 percent discount rate. The 8 percent discount rate is both the rate used in the Offshore EIA[17] and the average reported by all Section 308 Survey respondents (Section 308 Questionnaires; CBI data in rulemaking record).

For the Major Pass dischargers, EPA discounts annual project cash flows using a 7 percent discount rate. This is the production-weighted average for the Major Pass projects that reported a discount rate to EPA.

For Louisiana Open Bay dischargers and Texas Individual Permit applicants, EPA uses a company-specific nominal discount rate taken from the Section 308 Survey. The nominal discount rate is decreased by the inflation factor (described in A.1.7) to obtain the real discount rate. For respondents who were missing data or who indicated a nominal discount rate of less than 4 percent or greater than 20 percent, EPA substituted the average nominal discount rate for operators in these regions, as reported in the Section 308 Survey. The Agency assumes that rates higher than 20 percent are "hurdle rates" rather than discount rates. The "hurdle rate" is the minimum rate of return required for a company to undertake prospective projects.

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[17]U.S. EPA. 1993. Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry. Washington, D.C. January.

APPENDIX B

EPA ECONOMIC MODEL FOR COASTAL PETROLEUM PRODUCTION IN COOK INLET, ALASKA, AND THE MAJOR PASSES OF THE MISSISSIPPI RIVER

B.1 INTRODUCTION

The EPA model for Cook Inlet platforms and Major Pass dischargers simulates the costs and petroleum production dynamics expected at the platform or facility level in the development and operation of a coastal oil and gas project. Data to define a platform or facility and its petroleum reservoir are entered into the model. Then, through a series of internal algorithms, the model calculates the economic and engineering characteristics of the project.

The model is structured to be flexible. It is capable of modeling projects that are dynamic, with development occurring over a 10-year drilling period and specific drilling planned during that period. Furthermore, inputs for a wide variety of variables that define the development and production project can be user-specified. These inputs include drilling schedules, operating costs, initial petroleum production, production decline rates, tax rate schedules, and wellhead prices.

The model calculates costs and production performance for each year of the project's estimated lifetime. Additional outputs from the model include total production volume, project revenues, and both present value and nondiscounted summary statistics. Annual values and summary statistics are used to evaluate both the project and the effects of proposed pollution control regulations.

B.1.1 Model Phases

The project life of a coastal operation producing 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 the start of delineation to the start of development, 4) from the start of development to the start of production, and 5) production.

The Cook Inlet/Major Pass model evaluates operations that have, for the most part, completed the first four phases and are in the fifth phase. In some cases, there may be overlap between development, the fourth phase, and production (i.e., some wells may be drilled while production continues at other wells associated with the operation). For multiple-well platforms and facilities, the impetus to increase declining production is considerable if the operation can maintain profitability. The EPA model is capable of handling such situations.

The projects modeled are assumed to operate as long as they are profitable, up to 30 years. Algorithms within the model evaluate project economics annually, and the project is shut down when operating cash flow goes negative.

B.1.2 Economic Overview of the Model

The economic characteristics of the model phases are quite different. Phases one through four generate cash outflows; no revenues are earned during these periods. Since all the projects examined using the Cook Inlet/Major Pass model are already operating, costs incurred during the first four phases are treated as sunk costs, except in the case of costs for ongoing development (i.e., drilling of new and recompleted wells while production from other wells continues). Sunk costs are not incorporated in project evaluation. The fifth phase, production, typically generates net cash inflows. During this phase, the project continues to operate as long as operating cash inflows exceed nondiscretionary cash expenses.

B.1.2.1 Cash Flows—Categorization

The model deals with a number of basic cash flows (or resource transfers) in the development and production phases. The basic cash flows are as follows:

Development Phase:	Well drilling costs—costs of drilling a recompletion or new production well.
	Incremental drilling costs—additional costs 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—costs of operating and maintaining the well.
	Incremental O&M costs—additional costs due to new or revised regulations concerning produced water or drilling wastes.
	Incremental capital costs—additional costs due to new equipment required for additional pollution control of produced water or drilling wastes.

B.2 STEP-BY-STEP DESCRIPTION OF THE MODEL

This section provides a sequential overview of how the model operates, starting with the production phase and ending with the shut down of the project either after 30 years of production or when the project becomes unprofitable. The inputs, calculations, and outputs for a sample oil and gas platform are used in Figure B-1 to illustrate the model's algorithms.

The following discussion is based on the computer printout attached to this appendix. Identification numbers for specific lines are given in the left-hand margin. Table B-1 provides a list of user-specified inputs. All dollar values (e.g., costs and revenues) are expressed in thousands of 1995 dollars. Due to rounding, values on the spreadsheet may differ in the final digit from numbers presented in the text.

Phases one through three (Leasing, Exploration, and Delineation) are not detailed here because EPA assumes they are completed prior to the base year of the model.

Line 1 identifies the operation and the pollution control options being analyzed.

Line 2 is the real discount rate, i.e., the cost of capital. This value is used throughout the model to discount future cash inflows, cash outflows, and production so that they can be summarized in present value terms.

TABLE B-1

EXOGENOUS VARIABLES USED IN THE COOK INLET/MAJOR PASS PRODUCTION LOSS MODEL

Line Number	Parameter
2	Real discount rate
3	Inflation rate
5	Percent of costs considered expensible intangible drilling costs
8	Pollution control capital costs
27	1997 estimated oil production
28	1997 estimated gas production
30	Oil and gas production decline rate
32	Oil royalty rate
33	Gas royalty rate
34	Federal corporate tax rate
35	State corporate tax rate
37	Depreciation schedule
38	Severance tax rate—oil
39	Severance tax rate—gas
42	Years at peak production
43	Oil—peak production rate (bbl/day)
44	Gas—peak production rate (MMcf/day)
45	Total number of production wells drilled or recompleted
47	Wellhead price per barrel—oil
48	Wellhead price per Mcf—gas
49	Days of production per year
50	Total operating costs
51	Annual pollution control equipment operating cost (produced water)
52	Pollution control operating cost (drilling wastes)

Line 3 is the inflation rate. This parameter is used to reduce the value of the deductions for depreciation and cost-basis depletion in future years (see Appendix A).

Lines 4 and 5 contain information relevant to the calculation of project taxes. The flag in line 4 indicates whether the operation being modeled is an integrated (major) or independent company. As discussed in Appendix A, majors must calculate depletion on a cost basis, while independents may choose to do so on either a cost or a percentage basis.

Major and independent operators also differ with respect to the treatment of capital investments in calculating taxable income. Independents may expense 100 percent of their "Intangible Drilling Costs" (IDCs), while majors may expense only 70 percent. The expensing of these costs reduces taxable income in the year in which they are expensed and may provide a significant tax shelter.

It is assumed that the taxpayer (oil company) elects to expense intangible drilling costs in the year in which they are incurred. Intangible drilling costs are estimated, on the average, to represent 60 percent of the costs of production wells and their infrastructure.[1,2,3] Hence, independents may expense 60 percent of total production-well drilling costs (1.00 x 0.60), and majors may expense 42 percent (0.70 x 0.60). The percentage of drilling costs that are eligible for expensing is given in line 5.

B.2.1 Development Phase

During the development phase, the infrastructure required to extract oil reserves from a site is constructed. Development drilling is also conducted to increase production or to replace nonproducing wells on existing sites.

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[1]American Petroleum Institute. 1986. 1984 Survey on Oil and Gas Expenditures. Washington, D.C. October.

[2]U.S. Department of Commerce, Bureau of the Census. 1983. Annual Survey of Oil and Gas, 1981, Current Industrial Reports, MA-13k(81)-1.

[3]U.S. Department of Commerce, Bureau of the Census. 1982. Annual Survey of Oil and Gas, 1980, Current Industrial Reports, MA-13k(80)-1, March.

The costs of platform production equipment and other infrastructure are entered in line 7. In the Cook Inlet/Major Pass model, the value on line 7 is 0 because platform costs have already been incurred and are considered sunk costs. Additional costs for the construction and installation of pollution control equipment are entered separately in line 8. EPA assumes that pollution control capital costs are incurred in year 1.

Since the development phase of an oil and gas project may overlap with the production phase, the model is designed to incorporate the annual costs of development and increases in production from new and recompleted wells into estimates of total annual expenses and revenues. Lines 9 through 13 show the number of new and recompleted wells planned and the costs associated with drilling these wells. The drilling cost for a well depends on the depth drilled, environmental requirements, and regional costs for parts and labor.

The development phase in the model is structured to accommodate the drilling of production wells according to the drilling schedules provided by the operator. Separate entries for the drilling cost per well and the number of wells drilled each year appear in lines 15 through 20.

Lines 21 through 23 calculate the costs incurred each year from the drilling of production wells and the construction of production and pollution control facilities. The total annual capital development costs are given in line 24.

Expensed development costs, line 25, are the product of total drilling costs (line 24) and the percent of drilling costs eligible for expensing (line 5). All costs not eligible for expensing are capitalized and treated as depreciable assets for tax purposes. Note, in particular, pollution control costs (even drilling of injection wells) are not eligible for expensing as per tax code requirements. Capitalized development costs appear in line 26.

B.2.2 Production Phase

In the production phase of the project, a variety of financial and engineering variables interact to form the well's economic history. Oil and gas production figures for 1997 are given in lines 27 and 28.

Line 30 provides the production decline rate for oil and gas. The EPA model uses this rate to create an exponential function for production decline so that a constant proportion of the remaining reserves is produced each year. For every barrel produced in the initial year of operation in this sample project, 0.92 barrel is produced in the second year, $(0.92)^2$ or 0.846 barrel in the third year, and so on.

The EPA model is capable of handling cost escalation (see line 31). In this report, EPA is considering costs in real terms, and thus no escalation is assumed.

The royalty rates paid to the lessor of the land are provided in lines 32 and 33. Federal and state corporate tax rates are listed in lines 34 and 35. Line 37 is the depreciation schedule for capitalized oil and gas equipment. State severance taxes on oil and gas are given in lines 38 and 39, respectively. Note the flag for calculating severance taxes for Alaska, since these must be adjusted by the Economic Limit Factor (ELF); see previous discussion of the ELF in Appendix A.

Basic information describing the production phase of the project is listed in lines 40 through 53. The number of years that a well produces at its peak rate is given in line 42. The per well peak production rates for oil and gas are given in lines 43 and 44, respectively. These rates apply to wells drilled or recompleted and brought on line in the model years. Once these wells cease producing at peak rates, production volumes decline annually according to the decline rate in line 30. The operator's future drilling plans are summarized in lines 45 and 46.

The wellhead prices for oil and gas are entered on lines 47 and 48. These values are in 1995 dollars.

Line 49 indicates the number of days per year that a platform or facility produces. EPA assumes that the platforms and facilities in the production loss model operate continuously.

Annual operating costs are entered on line 50, while lines 51 through 53 contain the incremental operating costs incurred in complying with pollution control regulations for water and drilling waste disposal. Note that drilling wastes are generated by both the recompletion of existing wells and the drilling of new wells.

B.2.2.1 Production Volume Calculations

The next several lines in the model calculate annual production volumes for oil and gas, based on the initial production rates given in lines 27 and 28, the decline rate in line 30, and the operator's future drilling plans. Line 54 contains the number of producing wells brought into service each year. Line 55, the total barrels of oil produced per day, is the sum of current production (from 1997, declined at the appropriate rate) and production from the new wells brought into service each year. MMcf of gas per day (line 59) is calculated in the same manner. The annual oil and gas production numbers in lines 57 and 60 are the estimated daily production numbers multiplied by the number of days of production per year (line 56, repeated from line 49).

In general, production for a group of wells going into service in the same year is calculated as follows:

$$\text{Annual Production} = \begin{matrix}\text{Number}\\ \text{of Wells}\end{matrix} \times \begin{matrix}\text{Barrels}\\ \text{per Day}\\ \text{per Well}\end{matrix} \times \text{Decline Rate}^{a} \times \begin{matrix}\text{Number}\\ \text{of Days}\end{matrix}$$

$$\text{where } a = \text{year of production} - \text{number of years at peak production}$$

For projects with new wells going into service in different years, the equation is expanded in the following manner:

$$\begin{aligned}\text{Daily Production Year 2} &= 3 \text{ wells} \times 500 \text{ bopd}\\ &= 1{,}500 \text{ bopd}\\ \text{Year 3} &= (3 \times 500 \times 0.92)\end{aligned}$$

If additional wells were drilled in year 4,

$$\begin{aligned} \text{Year 4} &= (3 \times 500 \times 0.92^2) + (3 \times 500) \\ &= 1{,}270 + 1{,}500 \text{ bopd} \\ &= 1{,}770 \text{ bopd} \end{aligned}$$

and so forth.

The price per barrel is repeated in line 58 for convenience in cross-checking the gross revenues from oil production (line 62). Lines 61 and 63 list the wellhead price per Mcf of gas and gross revenues from gas production.

B.2.2.2 Income Statement

Lines 62 through 94 comprise an income and cash flow statement that is repeated annually for a 30-year project lifetime (see also lines 103 through 135 and lines 144 through 176). Since most projects become uneconomical during this 30-year timeframe, line 85 checks for negative net cash flow. When cash flow is negative, EPA assumes the project shuts down and actual production, revenues, and cash flows are reset to zero in lines 86 through 94.

Lines 62 and 63 list revenues from oil and gas production. Total gross revenues for the year are given in line 64. Royalty payments (lines 65 and 66; see lines 32 and 33 for royalty rates) are calculated on the basis of gross revenues. Severance taxes are then calculated on the basis of gross revenues minus royalty payments (lines 67 and 68; see lines 38 and 39 for severance tax rates). Note that the production loss model is capable of calculating the ELF applied to severance taxes in Alaska (see Appendix A for a more complete discussion of Alaska's severance tax regulations). Since the sample project here is assumed to produce oil only and the oil ELF in Cook Inlet currently is negative (and thus is not applied), both the oil and gas ELFs are set to zero.

Net revenues, line 69, are calculated as:

$$\text{Net Revenues} = \text{Total Gross Revenues} - \text{Royalty Payments} - \text{Severance Taxes}$$

Thus, for year 1:

$$\text{Net Revenues} = \$11{,}617 - \$1{,}452 - \$37$$
$$= \$10{,}128$$

Operating costs are given in lines 70 and 71. Line 70 lists the operating costs estimated for the platform or facility itself. Incremental operating costs for compliance with pollution control regulations appear in line 71. The latter figure reflects incremental costs due to both produced water and drilling waste requirements.

Operating earnings (line 72) are defined as net revenues (line 69) minus operating costs (line 70) minus pollution control operating costs (line 71). For year 2 of the project:

$$\text{Operating Earnings} = \text{Net Revenues} - \text{Operating Costs} - \text{Pollution Control Operating Costs}$$
$$= \$16{,}914 - \$5{,}606 - \$455 = \$10{,}853$$

Lines 73 and 74 divide capital costs into two categories for use in calculating the project's taxable income. Line 73 contains the capital costs that can be expensed (in this case, IDCs, or costs for drilling new and recompleted wells multiplied by the percentage in line 5). EPA assumes that oil and gas companies expense the maximum allowable portion of their capital costs. Line 74 contains the capital costs that must be capitalized, including pollution control capital costs and nonexpensible development drilling costs.

The adjusted depreciation allowance in line 75 is calculated on the basis of the capitalized costs in line 74 and the accelerated depreciation schedule in line 37. In model year 1, for example, the unadjusted depreciation allowance is the product of $2,500 (capitalized costs) and the depreciation rate for the appropriate year (e.g., $2,500 x 14.29% = $357 for the first year of operation for the project [year 1]). Because the model's values are given in constant dollars, the figure of $357 must then be adjusted for inflation, using the rate in line 3, as follows: $\$357 \div (1 + \text{inflation rate})^{\text{Year X}}$ or $\$357 \div (1.03)^1 = \$347$. This adjusted value is taken as a deduction against the taxable income associated with the project.

In model year 2, the adjusted depreciation allowance contains the second-year effects from the capital costs for model year 1 and first-year effects from the capital costs for model year 2:

$$\text{Adjusted Depreciation Allowance} = \frac{(\$2{,}500 \times 24.49\%) + (\$7{,}736 \times 14.29\%)}{(1 + 0.03)^2}$$

$$= \$1{,}623 \text{ (note rounding)}$$

Line 76, earnings before interest, taxes, and oil depletion allowance (ODA), is derived by subtracting expensed capital costs and depreciation and amortization from operating earnings. For year 2,

$$\begin{array}{c}\text{Earnings Before} \\ \text{Interest and ODA}\end{array} = \$10{,}853 - \$5{,}621 - \$1{,}623 = \$3{,}609$$

As discussed in Appendix A, the depletion allowance (line 77) is a means of treating annual oil and gas production as a wasting asset for tax purposes. For major producers, the depletion allowance is calculated on a cost basis, while for independents, it is calculated on a percentage basis. For the years shown here in the sample model, there is no depletion allowance because the sample project is a major producer, leasehold costs are treated as sunk costs, and major producers must deplete on a cost basis taking leasehold costs into account.

Earnings before interest and taxes (EBIT, line 78) is defined as earnings before interest and ODA (line 76) minus the adjusted oil depletion allowance (line 77). The figure on line 78 forms the basis for calculating federal and state income taxes in lines 79 and 80. Taxes are based on the rates given in lines 34 and 35. For Major Pass operators who must pay Louisiana state taxes, state taxes are subtracted from earnings before federal taxes are calculated. Earnings before interest and after taxes are given in line 81.

Project cash flows from operations, line 82, are determined by adding costs expensed for tax purposes, depreciation, and depletion back into earnings after taxes. The net cash flow from operations for year 2 is \$2,382 + \$5,621 + \$1,623 = \$9,626.

Whether or not the project continues to operate is determined on the basis of operating earnings (line 72). If (net revenues - total operating costs - pollution control operating costs) is less than 0, the project is assumed to shut down. Under such circumstances, net cash flow from operations (line 82) will also be 0. The model prints a "1" in line 85 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 oil and gas are no longer being produced and sold. Lines 86 through 94 restate production volumes, revenues, and cash flow in the event of a shutdown (i.e., production and revenues are set to zero after the project shuts down). The model allows a negative tax to be calculated in the shutdown year and continues to calculate depreciation after shutdown because it is assumed that the project is part of a larger, ongoing company and that such deductions can be used to adjust taxable income from the company's other operations.

The income statement for the second and third decades of operation are found on lines 103 through 135 and lines 144 through 176, respectively.

B.2.3 Summary Statistics

To summarize the project's economics, all costs and revenues associated with the project from year 1 to its end are put in present value terms as of the base year, as well as totaled; see lines 177 through 209.

The present value (PV) of total company costs (line 190) is the sum of the present values of the parameters listed in Table B-2. This parameter provides a measure of the present value of net company resources expended in the development and operation of a petroleum project. Entries marked with a "plus" in the column contribute to corporate costs. Surplus depreciation lowers corporate costs and is 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 191). These costs are apportioned by the ratio of oil revenues to total revenues. An analogous procedure is followed to obtain the total company costs for gas (see line 192).

The capital and the annual operation and maintenance costs for incremental pollution control of produced water effluents and drilling wastes are given in terms of present value and are annualized at 7 percent over 10 years. The annualized cost is given in line 194. Since capital expenditures for pollution control equipment generate a tax shield for the company, the net impact of these expenditures on an operation is equal to the total pollution control capital costs minus the tax shield from depreciation. The annualized cost with the depreciation tax shield taken into account is given in line 195.

Oil and gas production is also discounted and stated in present value equivalent terms (see lines 197 through 199). Corporate costs per barrel, corporate costs per Mcf, and total corporate costs per BOE are obtained by dividing the present value of the company costs by the present value equivalent of production (see 200 through 202).

The present value of social costs (lines 203 through 205) provides a measure of the value of net social resources expended in the development and operation of coastal 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 B-2. Social cost per unit of production is obtained by dividing the social cost by the present value equivalent of production (lines 206 through 208).

TABLE B-2

COST AND CASH FLOW USES IN THE COOK INLET PRODUCTION LOSS MODEL

Cost or Cash Flow Item	Company Cost	Social Cost	Depre-ciation
Total capitalized development costs			+
PV of capital investment cash flows	+		
PV of pollution control costs - operations	+	+	
PV of pollution control costs - capital	+		+
PV of royalties	+		
PV of severance taxes	+		
PV of operating costs	+	+	
PV of income taxes	+		
PV of surplus depreciation	-		
PV of all investment costs		+	

The net present value of the project, line 209, is calculated as:

$$
\begin{aligned}
\text{Net Present Value} &= \text{PV of Cash Inflows} - \text{PV of Cash Outflows} \\
&= \text{PV of Cash Flows from Operations} \\
&\quad - \text{PV of Investment Cash Flows} \\
&\quad - \text{PV of Leasehold Costs} \\
&\quad + \text{PV of Surplus Depreciation}
\end{aligned}
$$

A positive net present value is indicative of a profitable project at the assumed discount rate (i.e., the project analyzed generates more revenue than would be generated by investing the capital in another project with an expected rate of return equal to the assumed discount rate).

The internal rate of return (line 210) 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.

The number of years that the project operates is shown in line 211. This number reflects the total number of years that the project operates with a positive cash flow.

FIGURE B-1
COOK INLET/MAJOR PASS PRODUCTION LOSS MODEL

DATE: 25-Sep-96
FILE: D:\SAMPLEA2.WK4

RESULTS OF MODEL - COPIED FROM END OF SHEET		
PV BOE	6,853,440	*Present Value - BOE*
TOTAL BOE	10,814,196	*Total Non-Discounted - BOE*
NPV	$21,112	*Net Present Value - Production*
YRS. PROD	14	*Producing Years before Closure*
PVRYLT	$13,633	*Present Value - Royalties*
PVSEVTAX	$343	*Present Value - State & Severance Taxes*
PVINCTAX	$12,099	*Present Value -Fed Income Tax*

COASTAL OIL & GAS PRODUCTION LOSS MODEL -- PLATFORM/FACILITY LEVEL ANALYSIS

MANUALLY ENTER C8,D8, AND E8 AND RECALCULATE

GENERAL MODEL DATA	Platform	Water Option	Drill Option
(1) Project Type:	SAMPLE	ZD	ZD
(2) Real Discount Rate:	8%		
(3) Inflation Rate:	3%		
(4) Corp. Structure (1-major/2-indep.):	1		
(5) Percent Costs Expensed:	42%		

CONSTRUCTION COSTS

(6) Years Between Start of Delineation & Construction:	1	
(7) Total Platform Cost ($000):	$0	
(8) Pollution Control Capital Costs ($000):	$2,500	
(9) Number of Wells Drilled:	3.00	
(10) Number of Recompletions Drilled:	0.00	
(11) Number of Recomp. Wells Drilled per Year:	0.00	
(12) Drilling Cost Per Recompleted Well ($000):	$1,493	(Recompletion cost)
(13) Drilling Cost Per New Well ($000):	$4,461	

(14) Years of Construction:	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
(15) Drilling Cost Per Recompleted Well:	$1,493	$1,493	$1,493	$1,493	$1,493	$1,493	$1,493	$1,493	$1,493	$1,493
(16) Drilling Cost Per New Well:	$4,461	$4,461	$4,461	$4,461	$4,461	$4,461	$4,461	$4,461	$4,461	$4,461
(17) Drilling Mud Cost Increment:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18) Well Start:	1	2	3	4	5	6	7	8	9	10
(19) Number of New Wells Drilled:	0.00	3.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(20) Number of Recompletion Wells Drilled:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(21) Total Drilling Costs for Year:	$0	$13,384	$0	$0	$0	$0	$0	$0	$0	$0
(22) Annual Platform Cost:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(23) Pollution Control Capital Costs:	$2,500	$0	$0	$0	$0	$0	$0	$0	$0	$0
(24) Total Annual Capital Costs:	$2,500	$13,384	$0	$0	$0	$0	$0	$0	$0	$0
(25) Expensed Capital Costs:	$0	$5,621	$0	$0	$0	$0	$0	$0	$0	$0
(26) Capitalized Capital Costs:	$2,500	$7,763	$0	$0	$0	$0	$0	$0	$0	$0

	FINANCIAL DATA								
	(27) 1997 Oil Production (BPD) - Platform/Facility	2000							
	(28) 1997 Gas Production (MMCF per day) - Platform/Facility	0.0							
	(29) Water:oil (bbl:bbl) or Water:gas (bbl:MMcf):	9.94							
	(30) Oil/Gas Prod. Decline Rate/Year (%):	92%							
	(31) Cost Escalator (%):	0%							
	(32) Oil Royalty Rate (%):	12.5%							
	(33) Gas Royalty Rate (%):	0.0%							
	(34) Federal Tax Rate (%):	34%							
	(35) State Corporate Tax Rate (%):	0%							
	(36) Average Depreciation Life (years):	7							
	(37) Deprec. rate (subsequent years):	14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%
	(38) State Severance Tax Rate-Oil:	99.00							
***	(If Alaska enter 99 in input sheet)								
	(39) State Severance Tax Rate-Gas:	99.00							
***	(If Alaska enter 99 in input sheet)								
	PRODUCTION DATA								
	(40) Gas Only? (1=yes, 0=no):	0							
	(41) Yrs Btwn Strt Dev & Strt Prod (<5):	0							
	(42) Number of Years at Peak Prod (=>1):	1							
	(43) Oil Peak Prod. Rate/Well(bb):	500							
	(44) Gas Peak Prod. Rate/Well(MMCF/D):	0							
	(45) Total Number of New Producing Wells Planned:	3.00							
	(46) Number of Wells Put in Service/Year:	0.00							
	(47) Price of Oil Per Barrel:	$15.91							
	(48) Price of Gas Per MCF:	$1.72							
	(49) Days of Production Per Year:	365							
	(50) Total Operating Costs ($000):	$5,606							
	(51) Produced Water Pollution Control Operating Costs ($000):	$200							
	(52) Drilling Waste Operating Cost -- New Well ($000):	$85							
	(53) Drilling Waste Operating Cost -- Recompleted Well ($000):	$0							

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
OIL, WATER, AND GAS PRODUCTION										
(54) Wells Put Into Production:	0.00	3.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Barrels of Oil Per Day (New Wells):	0	1500	1380	1270	1168	1075	989	910	837	770
Barrels of Oil Per Day (1997 Wells):	2000	1840	1693	1557	1433	1318	1213	1116	1026	944
(55) Barrels of Oil Per Day (All Wells):	2000	3340	3073	2827	2601	2393	2201	2025	1863	1714
(56) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(57) Barrels of Oil Per Year:	730000	1219100	1121572	1031846	949299	873355	803486	739207	680071	625665
(58) Price/Barrel of Oil:	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91
MMCF of Gas Per Day (New Wells):	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MMCF of Gas Per Day (1997 Wells):	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(59) MMCF of Gas Per Day (All Wells):	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(60) MMCF of Gas Per Year:	0	0	0	0	0	0	0	0	0	0
(61) Price/MCF of Gas:	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72
INCOME AND PARTIAL CASH FLOW STATEMENT FOR YEARS 1-10										
(62) Annual Oil Revenues ($000):	$11,617	$19,400	$17,848	$16,420	$15,107	$13,898	$12,786	$11,763	$10,822	$9,957
(63) Annual Gas Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(64) Total Revenues ($000):	$11,617	$19,400	$17,848	$16,420	$15,107	$13,898	$12,786	$11,763	$10,822	$9,957
(65) Royalty Payments-Oil ($000):	$1,452	$2,425	$2,231	$2,053	$1,888	$1,737	$1,598	$1,470	$1,353	$1,245
(66) Royalty Payments-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(67) Severance Taxes-Oil ($000):	$37	$61	$56	$52	$47	$44	$40	$37	$34	$31
(68) Severance Taxes-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
*** ELF for Alaska Severance Taxes-Oil:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
*** ELF for Alaska Severance Taxes-Gas:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(69) Net Revenues ($000):	$10,128	$16,914	$15,561	$14,316	$13,171	$12,117	$11,148	$10,256	$9,436	$8,681
(70) Total Operating Costs ($000):	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606
(71) Poll.Con.Operating Costs ($000):	$200	$455	$200	$200	$200	$200	$200	$200	$200	$200
(72) Operating Earnings ($000):	$4,322	$10,853	$9,755	$8,510	$7,365	$6,311	$5,342	$4,450	$3,629	$2,874
(73) Expensed Cap.Costs (Drilling & Poll. Cont.) ($000):	$0	$5,621	$0	$0	$0	$0	$0	$0	$0	$0
(74) Capitalized Costs ($000):	$2,500	$7,763	$0	$0	$0	$0	$0	$0	$0	$0
(75) Adjstd Depreciation & Amort ($000):	$347	$1,623	$2,140	$1,484	$1,029	$767	$745	$635	$265	$0
(76) Earnings Before Interest, Taxes, and ODA ($000):	$3,975	$3,609	$7,615	$7,026	$6,336	$5,544	$4,597	$3,814	$3,364	$2,874
(77) Adjusted Depletion Allowance ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(78) Earnings Before Interest and Taxes ($000):	$3,975	$3,609	$7,615	$7,026	$6,336	$5,544	$4,597	$3,814	$3,364	$2,874
(79) Federal Tax (Earnings-State Taxes) ($000):	$1,352	$1,227	$2,589	$2,389	$2,154	$1,885	$1,563	$1,297	$1,144	$977
(80) State Income Tax ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(81) Earnings Before Interest After Tax ($000):	$2,624	$2,382	$5,026	$4,637	$4,182	$3,659	$3,034	$2,518	$2,220	$1,897
(82) Net Cash Flow from Operations ($000):	$2,970	$9,626	$7,166	$6,121	$5,210	$4,426	$3,779	$3,153	$2,485	$1,897
(83) Capital Expenditures on Fixed Assets ($000):	$2,500	$13,384	$0	$0	$0	$0	$0	$0	$0	$0
(84) Net Cash Flow from Operations and Investments ($000):	$470	($3,758)	$7,166	$6,121	$5,210	$4,426	$3,779	$3,153	$2,485	$1,897
(85) Shutoff?	1	1	1	1	1	1	1	1	1	1
(86) Actual Oil Prod./Year (Barrels):	730000	1219100	1121572	1031846	949299	873355	803486	739207	680071	625665
(87) Actual Gas Prod./Year (MMCF):	0	0	0	0	0	0	0	0	0	0
(88) Actual Gross Revenues ($000):	$11,617	$19,400	$17,848	$16,420	$15,107	$13,898	$12,786	$11,763	$10,822	$9,957
(89) Actual Net Revenues ($000):	$10,128	$16,914	$15,561	$14,316	$13,171	$12,117	$11,148	$10,256	$9,436	$8,681
(90) Actual Net Cash Flow from Operations ($000):	$2,970	$9,626	$7,166	$6,121	$5,210	$4,426	$3,779	$3,153	$2,485	$1,897
(91) Actual Capital Expenditures on Fixed Assets ($000):	$2,500	$13,384	$0	$0	$0	$0	$0	$0	$0	$0
(92) Actual Net CF from Operations and Investments ($000):	$470	($3,758)	$7,166	$6,121	$5,210	$4,426	$3,779	$3,153	$2,485	$1,897
(93) Actual Federal Taxes Paid ($000):	$1,352	$1,227	$2,589	$2,389	$2,154	$1,885	$1,563	$1,297	$1,144	$977
(94) Actual State Income Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
OIL, WATER, AND GAS PRODUCTION										
(95) Wells Put Into Production:										
Barrels of Oil Per Day (New Wells):										
(96) Barrels of Oil Per Day (All Wells):	1577	1451	1335	1228	1130	1039	956	880	809	745
(97) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(98) Barrels of Oil Per Year:	575612	529563	487198	448222	412364	379375	349025	321103	295415	271782
(99) Price/Barrel of Oil:	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91
(100) MMCF of Gas Per Day (All Wells):	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(101) MMCF of Gas Per Year:	0	0	0	0	0	0	0	0	0	0
(102) Price/MCF of Gas:	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72
INCOME AND PARTIAL CASH FLOW STATEMENT FOR YEARS 11-20										
(103) Annual Oil Revenues ($000):	$9,160	$8,427	$7,753	$7,133	$6,562	$6,037	$5,554	$5,110	$4,701	$4,325
(104) Annual Gas Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(105) Total Revenues ($000):	$9,160	$8,427	$7,753	$7,133	$6,562	$6,037	$5,554	$5,110	$4,701	$4,325
(106) Royalty Payments-Oil ($000):	$1,145	$1,053	$969	$892	$820	$755	$694	$639	$588	$541
(107) Royalty Payments-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(108) Severance Taxes-Oil ($000):	$29	$26	$24	$22	$21	$19	$17	$16	$15	$14
(109) Severance Taxes-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
*** ELF for Alaska Severance Taxes-Oil:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
*** ELF for Alaska Severance Taxes-Gas:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(110) Net Revenues ($000):	$7,986	$7,347	$6,760	$6,219	$5,721	$5,264	$4,843	$4,455	$4,099	$3,771
(111) Total Operating Costs ($000):	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606
(112) Poll.Con.Operating Costs ($000):	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
(113) Operating Earnings ($000):	$2,180	$1,541	$953	$412	($85)	($543)	($964)	($1,351)	($1,708)	($2,036)
(114) Expensed Cap.Costs (Drilling & Poll. Cont.) ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(115) Capitalized Costs ($000) (*0 if no new drilling):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(116) Adjstd Depreciation & Amort ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(117) Earnings Before Interest, Taxes, and ODA ($000):	$2,180	$1,541	$953	$412	($85)	($543)	($964)	($1,351)	($1,708)	($2,036)
(118) Adjusted Depletion Allowance ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(119) Earnings Before Interest and Taxes ($000):	$2,180	$1,541	$953	$412	($85)	($543)	($964)	($1,351)	($1,708)	($2,036)
(120) Federal Tax (Earnings-State Taxes) ($000):	$741	$524	$324	$140	($29)	($185)	($328)	($459)	($581)	($692)
(121) State Income Tax ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(122) Earnings Before Interest After Tax ($000):	$1,439	$1,017	$629	$272	($56)	($358)	($636)	($892)	($1,127)	($1,343)
(123) Net Cash Flow from Operations ($000):	$1,439	$1,017	$629	$272	($56)	($358)	($636)	($892)	($1,127)	($1,343)
(124) Capital Expenditures on Fixed Assets ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(125) Net Cash Flow from Operations and Investments ($000):	$1,439	$1,017	$629	$272	($56)	($358)	($636)	($892)	($1,127)	($1,343)
(126) Shutoff?	1	1	1	1	0	0	0	0	0	0
(127) Actual Oil Prod./Year (Barrels):	575612	529563	487198	448222	0	0	0	0	0	0
(128) Actual Gas Prod./Year (MMCF):	0	0	0	0	0	0	0	0	0	0
(129) Actual Gross Revenues ($000):	$9,160	$8,427	$7,753	$7,133	$0	$0	$0	$0	$0	$0
(130) Actual Net Revenues ($000):	$7,986	$7,347	$6,760	$6,219	$0	$0	$0	$0	$0	$0
(131) Actual Net Cash Flow from Operations ($000):	$1,439	$1,017	$629	$272	$0	$0	$0	$0	$0	$0
(132) Actual Capital Expenditures on Fixed Assets ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(133) Actual Net CF from Operations and Investments ($000):	$1,439	$1,017	$629	$272	$0	$0	$0	$0	$0	$0
(134) Actual Federal Taxes Paid ($000):	$741	$524	$324	$140	$0	$0	$0	$0	$0	$0
(135) Actual State Income Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
OIL, WATER, AND GAS PRODUCTION										
(136) Wells Put Into Production:										
Barrels of Oil Per Day (New Wells):										
(137) Barrels of Oil Per Day (All Wells):	685	630	580	533	491	451	415	382	352	323
(138) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(139) Barrels of Oil Per Year:	250039	230036	211633	194703	179126	164796	151613	139484	128325	118059
(140) Price/Barrel of Oil:	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91	$15.91
(141) MMCF of Gas Per Day:	0	0	0	0	0	0	0	0	0	0
(142) MMCF of Gas Per Year:	0	0	0	0	0	0	0	0	0	0
(143) Price/MCF of Gas:	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72	$1.72
INCOME AND PARTIAL CASH FLOW STATEMENT FOR YEARS 21-30										
(144) Annual Oil Revenues ($000):	$3,979	$3,661	$3,368	$3,098	$2,851	$2,623	$2,413	$2,220	$2,042	$1,879
(145) Annual Gas Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(146) Total Revenues ($000):	$3,979	$3,661	$3,368	$3,098	$2,851	$2,623	$2,413	$2,220	$2,042	$1,879
(147) Royalty Payments-Oil ($000):	$497	$458	$421	$387	$356	$328	$302	$277	$255	$235
(148) Royalty Payments-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(149) Severance Taxes-Oil ($000):	$13	$12	$11	$10	$9	$8	$8	$7	$6	$6
(150) Severance Taxes-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
*** ELF for Alaska Severance Taxes-Oil:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
*** ELF for Alaska Severance Taxes-Gas:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(151) Net Revenues ($000):	$3,469	$3,192	$2,936	$2,701	$2,485	$2,286	$2,104	$1,935	$1,780	$1,638
(152) Total Operating Costs ($000):	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606	$5,606
(153) Poll.Con.Operating Costs ($000):	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
(154) Operating Earnings ($000):	($2,337)	($2,615)	($2,870)	($3,105)	($3,321)	($3,520)	($3,703)	($3,871)	($4,026)	($4,168)
(155) Expensed Cap.Costs (Drilling & Poll. Cont.) ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(156) Capitalized Costs ($000) (*0 if no new drilling):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(157) Adjstd Depreciation & Amort ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(158) Earnings Before Interest and ODA ($000):	($2,337)	($2,615)	($2,870)	($3,105)	($3,321)	($3,520)	($3,703)	($3,871)	($4,026)	($4,168)
(159) Adjusted Depletion Allowance ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(160) Earnings Before Interest and Taxes ($000):	($2,337)	($2,615)	($2,870)	($3,105)	($3,321)	($3,520)	($3,703)	($3,871)	($4,026)	($4,168)
(161) Federal Tax (Earnings-State Taxes) ($000):	($795)	($889)	($976)	($1,056)	($1,129)	($1,197)	($1,259)	($1,316)	($1,369)	($1,417)
(162) State Income Tax ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(163) Earnings Before Interest After Tax ($000):	($1,543)	($1,726)	($1,894)	($2,049)	($2,192)	($2,323)	($2,444)	($2,555)	($2,657)	($2,751)
(164) Net Cash Flow from Operations ($000):	($1,543)	($1,726)	($1,894)	($2,049)	($2,192)	($2,323)	($2,444)	($2,555)	($2,657)	($2,751)
(165) Capital Expenditures on Fixed Assets ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(166) Net Cash Flow from Operations and Investments ($000):	($1,543)	($1,726)	($1,894)	($2,049)	($2,192)	($2,323)	($2,444)	($2,555)	($2,657)	($2,751)
(167) Shutoff?	0	0	0	0	0	0	0	0	0	0
(168) Actual Oil Prod./Year (Barrels):	0	0	0	0	0	0	0	0	0	0
(169) Actual Gas Prod./Year (MMCF):	0	0	0	0	0	0	0	0	0	0
(170) Actual Gross Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(171) Actual Net Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(172) Actual Net Cash Flow from Operations ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(173) Actual Capital Expenditures on Fixed Assets ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(174) Actual Net CF from Operations and Investments ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(175) Actual Federal Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(176) Actual State Income Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

MODEL OUTPUT

(177) PV of Gross Revenues ($000):	$109,063		
(178) PV of Actual Net Revenues ($000):	$95,088		
(179) PV of Actual Net Cash Flows from Operations ($000):	$34,901		
(180) PV of Act. Net CF from Operations & Investmt. ($000):	$21,112		
(181) PV of Leasehold Cost ($000):	$0		
(182) PV of Actual Royalties - Oil ($000):	$13,633	$13,633	(Sum of Royalties)
(183) PV of Actual Royalties - Gas ($000):	$0		
(184) PV of Actual Severance Taxes - Oil ($000):	$343	$343	(Sum of Severance Taxes and State Taxes Paid)
(185) PV of Actual Severance Taxes - Gas ($000):	$0		
(186) PV of Actual State Income Taxes Paid ($000):	$0		
(187) PV of Actual Federal Income Taxes Paid ($000):	$12,099		
(188) PV of Actual Operating Costs (includes PC O&M) ($000):	$48,088		
(189) PV of Cash Flows from Actual Total Capital Expend. ($000):	$13,789		
(190) Total Company Costs ($000):	$87,952		
(191) Total Company Costs - Oil ($000):	$87,952		
(192) Total Company Costs - Gas ($000):	$0		
(193) PV Actual Poll. Ctrl. (Capital and O&M) Costs ($000):	$4,182		
(194) Annualized Poll.Cont.Costs ($000):	$489	(Annual Compliance Cost)	
(195) PV Actual PC Costs Net of Depreciation Tax Shield ($000):	$3,591		
(196) Annualized PC Costs Net of Depreciation Tax Shield ($000):	$420		
(197) PV Equiv. of Oil (bbl):	6,853,440	10,814,196	(Non-Discounted)
(198) PV Equiv. of Gas (MMCF):	0	0	(Non-Discounted)
(199) PV BOE	6,853,440	10,814,196	(Non-Discounted)
(200) Amortized Company Cost per bbl:	$12.83		
(201) Amortized Company Cost per Mcf:	$0.00		
(202) Amortized Company Cost per BOE:	$12.83		
(203) PV of Social Costs - Total:	$61,877		
(204) PV of Social Costs - Oil:	$61,877		
(205) PV of Social Costs - Gas:	$0		
(206) Amortized Social Cost per bbl:	$9.03		
(207) Amortized Social Cost per Mcf:	$0.00		
(208) Amortized Social Cost per BOE:	$9.03		
(209) Net Present Value of Project:	$21,112		
(210) Internal Rate of Return:	ERR	*only for NSPS, "ERR" indicates that the guess is not close enough	
(211) No. of Years of Production:	14		

*all PVs are adjusted back to year 0, according to whether they come from the production portion of the model or elsewhere
"ERR" indicates spreadsheet error but does not affect model results

APPENDIX C

LOUISIANA OPEN BAY AND TEXAS INDIVIDUAL PERMIT PRODUCTION LOSS MODEL

C.1 INTRODUCTION

This appendix describes in greater detail the production loss model used to estimate impacts to the Louisiana Open Bay dischargers and Texas Individual Permit applicants. Since the model operates on the same principles as the model described in Appendix B, some sections refer to Appendix B for more information.

The Open Bay/Individual Permit production loss model simulates the costs and petroleum production dynamics expected in the operation of the Louisiana Open Bay dischargers' and Texas Individual Permit applicants' coastal wells. Data to define each well are entered into the model. The model is structured to be flexible and is capable of using user-specified inputs for a number of variables. Inputs include, but are not limited to, operating costs, initial petroleum production, production decline rates, tax rate schedules, and wellhead prices.

The model analyzes the per well data through a series of internal algorithms developed to calculate the economic and engineering characteristics of each well. Outputs from the model include: production volume, project economics, and summary statistics on both an annual and an aggregate basis. EPA uses these annual values and summary statistics to evaluate the incremental effects of pollution control regulations on each well.

C.1.1 Model Phases

The Louisiana Open Bay and Texas Individual Permit wells analyzed in the production loss model are currently producing wells that discharge produced water. Since these wells are evaluated as individual entities, they have completed the first four phases of an oil and gas project's life as described in Section

B.1.1. The production loss model therefore focuses on only the fifth phase, the production phase, in estimating the possible effects of the Coastal Guidelines.

The wells in this analysis channel their production to treatment facilities that may accept produced water and petroleum from more than one well. The lifetime of the treatment facility is not dependent on the liftime of an individual well in this analysis since additional wells may be served by the facility or new wells may be drilled and served by the treatment facility in the future. Any well closures estimated using the production loss model therefore do not necessarily reflect the fate of the treatment facility.

C.1.2 Overview of the Economic Model

During the production phase of the well, there are a number of cash flows to consider, including revenue flows from oil and gas production, operation and maintenance costs for operating the well, and incremental costs (both capital and O&M) that stem from new or revised regulations concerning produced water.

C.1.2.1 Produced Water Assumptions

For all projects, water production is calculated as a function of total fluid production. 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 fluid production, EPA needs to estimate several parameters:

- Relationship of oil decline and water increase
- Decline rate of oil production
- Watercut (i.e., percentage of water in the produced fluid)

EPA assumes that oil production declines at an exponential rate. This is discussed in Appendix B. As oil production declines, water production increases, maintaining a constant volume of fluid. Figure C-1

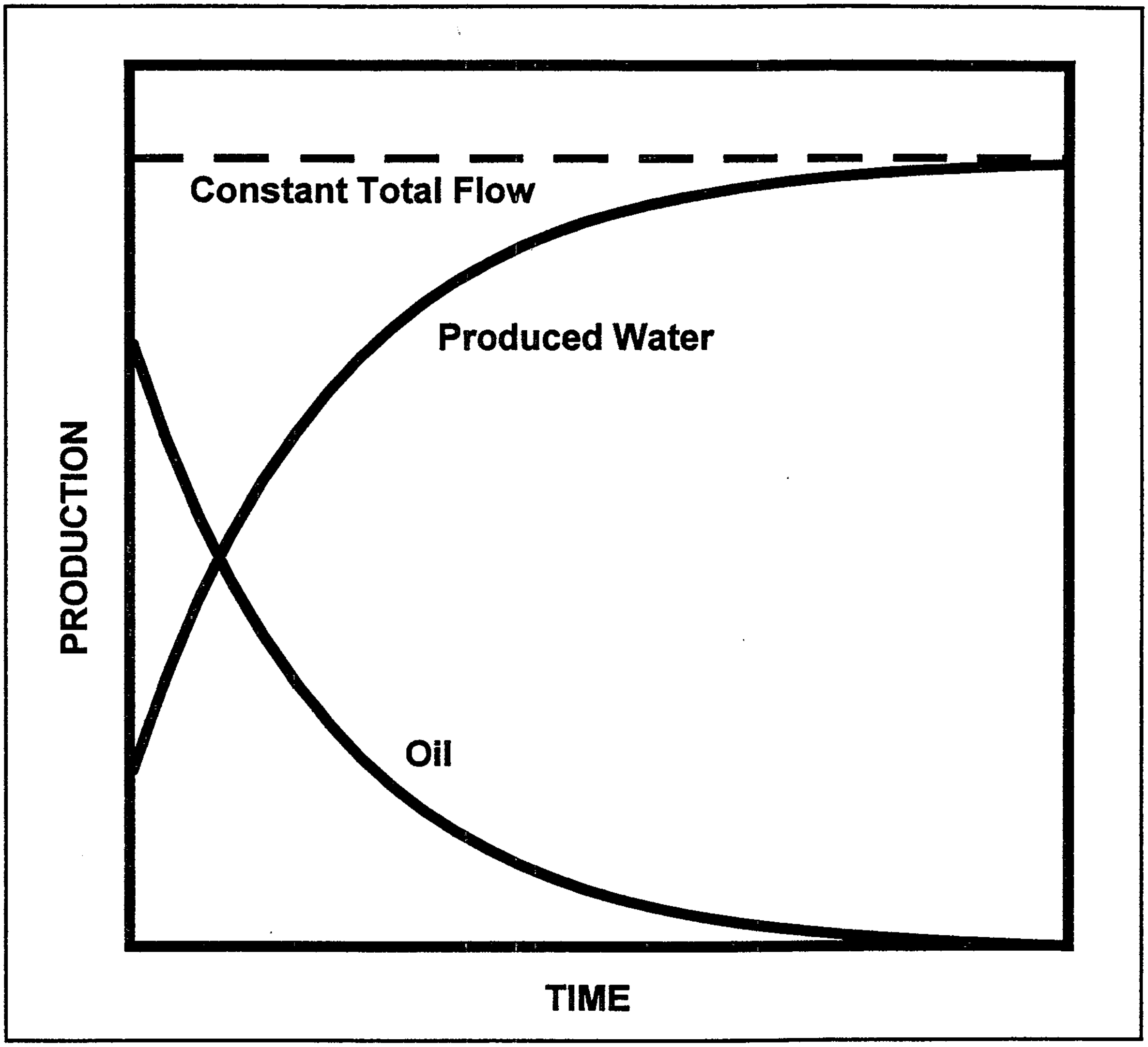

Figure C-1. Oil:Water relationship over time (exponential decline).

illustrates the oil and water production relationship over time. EPA estimates watercut data by calculating the ratio of daily water production to daily water and oil production from the Section 308 Survey data.

Since incremental regulatory costs are determined on a per barrel of produced water basis, the annual costs for produced water disposal increase annually.

C.2 STEP-BY-STEP DESCRIPTION OF THE MODEL

The following is a sequential overview of how the Open Bay/Individual Permit production loss model operates. The model begins in the production phase and ends with the shutdown of the well either after 30 years or when the well becomes unprofitable to operate. Inputs, calculations, and outputs for a sample oil- and gas-producing well are used to illustrate the model's algorithms.

This discussion is based on Figure C-2, the computer printout attached to the end of this appendix. Identification numbers for specific lines are given in the left-hand margin. Table C-1 lists user-specified inputs. <u>All dollar values are expressed in thousands of 1995 dollars, except for per-barrel costs, which are expressed in untruncated 1995 dollars</u>. Because of rounding, values on the spreadsheet may differ in the final digit from numbers presented in the text.

C.2.1 General Model Data

<u>Lines 1 and 2</u> identify the individual well being analyzed. Summary financial rates applied throughout the model follow. <u>Line 3</u> is the real discount rate (i.e., the cost of capital). This value is specific to the well and is determined from oil and gas operator responses to the Section 308 Survey. Since the value contained in the Survey data is the nominal discount rate, EPA calculates the real discount rate using the inflation rate presented in <u>line 4</u>. In cases where the discount rate was missing or an operator supplied a discount rate that appeared to be a hurdle rate (values greater than 20 percent) or that had an extremely low value (less than 4 percent), EPA substituted the average nominal rate for operators who reported a discount rate.

TABLE C-1

EXOGENOUS VARIABLES USED IN THE GULF OF MEXICO PRODUCTION LOSS MODEL

Line Number	Parameter
3	Real discount rate
4	Inflation rate
5	Water:oil or water:gas ratio
6	Oil and gas production decline rate
7	Cost escalator
8	Royalty rate
9	Corporate structure (major or independent)
10	Federal corporate income tax rate
11	State corporate income tax rate
13	Depreciation schedule
14	Severance tax rate—oil
15	Severance tax rate—gas
17	Oil—initial production rate (bbl/day)
18	Gas—initial production rate (MMcf/day)
21	Wellhead price per barrel—oil
22	Wellhead price per Mcf—gas
23	Total operating costs
24	Pollution control annual cost (per barrel of water)
25	Days of production per year

In the production phase of a well, a variety of financial and engineering variables interact to form the well's economic history. Line 5 provides the water to oil or water to gas ratio for the well. As discussed previously in this appendix, this rate is important in determining the future water production of the well and adjusting the incremental operating costs appropriately. Line 6 provides the production decline rate for oil and gas. The EPA model incorporates an exponential function for production decline (i.e., a constant proportion of the remaining reserves is produced each year). The decline rate predicted for coastal wells in the Gulf of Mexico region is 15 percent. In other words, each year, a well produces 15 percent less oil and/or gas.

The EPA model is capable of handling cost escalation (see line 7). In this report, we are considering costs in real terms, and thus no escalation is assumed.

Lines 9 through 13 list values important in calculating federal and state tax impacts of pollution control regulations. Line 9 indicates whether a firm is a major or independent oil producer (i.e., the firm's corporate structure). As discussed in Appendix A, the corporate structure is a factor in the calculation of the adjusted depletion allowance shown in line 51 and discussed below. Line 10 is the marginal Federal corporate income tax rate. Line 11 is the state corporate tax rate. The state tax rate changes depending on the state in which the well is located. For Louisiana, the state corporate tax rate is 8 percent; in Texas, there is no corporate tax on oil and gas.[1] Lines 12 and 13 contain the depreciation schedule for capitalized expenditures on oil and gas equipment. Since the Louisiana Open Bay dischargers and Texas Individual Permit applicants are analyzed on the well level, expenditures on well drilling/recompletion are not included in the model, and the depreciation schedule is not referenced. Pollution control capital costs, which would generally be depreciated, are instead annualized and incorporated into the model on a per barrel of produced water basis (discussed later in this section).

In addition to taxes, oil and gas operators generally pay royalty and severance taxes. The royalty rate paid to the lessor of the land is provided in line 8. This value is a well-specific rate determined from Survey data. If, in the Survey, the operator reported a royalty rate above 80 percent, EPA adjusted the rate to 16.6 percent for oil or 16.9 percent for gas. Royalty rates higher than 80 percent are considered unrealistic, possibly reflecting an operator's working interest share rather than a royalty rate, or resulting

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[1]Commerce Clearing House. 1994. State Tax Handbook. Commerce Clearing House, Inc., Tulsa, OK.

from an error in the reporting of royalties in the Survey data.[2] State severance taxes on oil and gas are given in lines 14 and 15.[3] Note that the model is capable of calculating the Economic Limit Factor for Alaska severance taxes. The standard state severance tax rates are used for Louisiana and Texas.

Basic production information used in the model is listed in lines 16 through 25. The number of years that a well produces at its initial rate is given in line 16. Lines 17 and 18 contain the well's production rates for oil and gas in the first year modeled. These numbers are based on well-specific Section 308 Survey data. Production volumes decline annually in the model as per the production decline rate in line 6.

Wellhead prices per barrel of oil and per Mcf of gas are given in lines 21 and 22. These values are inflated to 1995 dollars from Section 308 Survey data.

The operating cost for the well is shown in line 23. EPA estimated the operating cost per well by dividing the total operating costs for each individual operator's coastal oil and gas operations, reported in the Survey, by the number of coastal wells operated, also reported in the Survey data. The resulting value is an average operating cost for a coastal well operated by the Survey respondent. No data were collected on the annual operating costs for specific wells in the Section 308 Survey.

The incremental pollution control costs for produced water are given in line 24. This figure represents the amount (per barrel of produced water) by which disposal costs will increase because of the regulation. The per barrel cost is obtained by dividing the estimated annual pollution control costs for a given facility by the current volume of produced water for that facility. Annual pollution control costs, in turn, are determined by annualizing capital costs for pollution control equipment at 7 percent over 10 years and adding the resultant figure to annual O&M costs. This assumption regarding incremental pollution control costs is equivalent to the assumption that the treatment/separation facility is operated such that all wells must pay their own way. In reality, some wells might not support themselves, but these wells are not

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[2]The Survey asked respondents for total wellhead price and wellhead price net of royalties. The royalty rate was calculated based on the difference between these two figures. Thus, if a respondent inadvertently submitted royalties per barrel instead of wellhead price net of royalties, the royalty rate calculated for the respondent would have been incorrectly estimated at around 80 to 90 percent.

[3]Commerce Clearing House. 1994. State Tax Handbook. Commerce Clearing House, Inc., Tulsa, OK.

shut in because the overall project is more economical with them producing. It is thus somewhat conservative to treat pollution control costs in this manner. Annualizing pollution control capital costs, moreover, reduces the well's tax shield because the costs are distributed evenly over 10 years, whereas depreciation allows a producer to reduce tax burdens to a greater extent in the early years of the project. Tax burdens to the producer are thus overstated in a present value sense.

The model calculates the total incremental cost to the individual well by multiplying the value in line 24 by the barrels of water produced each year. Assuming fluid production is constant, the incremental costs increase each year as water production increases.

Line 25 shows the number of days per year the well operates. EPA assumes that the wells in the production loss model operate continuously.

C.2.1.1 Production Volume Calculations

Lines 26 through 35 calculate annual production volumes for oil, gas, and water, based on the initial production rates given in lines 17 and 18 and the decline rate in line 6. Production volumes can be modeled every year for up to 30 years (see also lines 67 through 75 and lines 107 through 115). Line 26 lists the number of producing wells in service. In the Louisiana Open Bay/Texas Individual Permit model, this value is always 1 in year 1 because only single wells are analyzed. Line 27 indicates the barrels of oil per day produced by the well. This figure is multiplied by the number of days of production per year (the value in line 26 repeated in line 28) to calculate the number of barrels of oil produced annually (line 29). Annual oil production, in turn, is multiplied by line 30, the price per barrel of oil (repeated from line 21), to calculate the revenues generated from that production. Line 31 shows the barrels of water produced per day. EPA assumes that the total volume of fluid (oil and water) pumped remains constant, although oil production declines. Line 32 calculates the sum of the two fluids to check that total fluid is constant.

Lines 33 through 35 calculate the total volume of gas generated per year (note that the zeroes in line 33 are rounded values: the well actually produces approximately 100 Mcf per day in model year 1). Total gas revenues are calculated based on the price of gas in line 35.

C.2.2 Income Statement

Lines 36 through 56 comprise an income and cash flow statement that is repeated annually for a 30-year project lifetime (see also lines 76 through 96 and lines 116 through 135). Since some projects become uneconomical during this 30-year period, line 57 checks for negative net cash flow, which, in this model, is primarily driven by operating earnings. When cash flow is negative, EPA assumes the project shuts down and actual production, revenues, and cash flows are reset to zero in lines 58 through 64.

Lines 36 and 37 list revenues from oil and gas production. Total gross revenues are given in line 38. Royalty payments (lines 39 and 40; see line 10 for the royalty rate) are calculated on the basis of gross oil and gas revenues. Severance taxes are then calculated on the basis of gross revenues minus royalty payments (lines 41 and 42; see lines 13 and 14 for severance tax rates).

Net revenues (line 43) represent:

$$\begin{aligned}\text{Net Revenues} = \ & \text{Total Gross Revenues} \\ & - \ \text{Oil Royalty Payments} - \text{Gas Royalty Payments} \\ & - \ \text{Oil Severance Taxes} - \text{Gas Severance Taxes}\end{aligned}$$

Thus, for Year 1 for the model well, net revenues are:

$$\begin{aligned}\text{Net Revenues} &= \$1{,}697 - \$274 - \$9 - \$205 - \$2 \\ &= \$1{,}207\end{aligned}$$

Operating costs are given in lines 44 and 46. Line 44 lists the operating cost estimated for the well itself. Incremental operating costs for pollution control appear in line 45, and are the product of the per-barrel of produced water cost, the number of days of operation, and the pollution control costs. As discussed in Appendix A, pollution control costs in the Open Bay/Individual Permit model reflect the costs of the pollution control equipment annualized at 7 percent over 10 years, combined with yearly operating costs.

Operating earnings (line 49) are defined as net revenues (line 43) minus operating costs (line 44) minus pollution control operating costs (line 46). For Year 1 of the project:

Operating Earnings = Net revenues - Operating costs - Pollution control operating costs

= $1,207 - $40 - $19 = $1,148

Depreciation and amortization would normally be subtracted from operating earnings (line 49) to calculate earnings before interest and ODA in line 50. Because capital costs are included in the per barrel pollution control costs discussed above rather than considered separately in the Open Bay/Individual Permit model, both depreciation and amortization are zero and line 50 equals line 49.

As discussed in Appendix A, the depletion allowance (line 51) is a means of treating annual oil and gas production as a wasting asset for tax purposes. It can be calculated on either a cost or a percentage basis. Depletion for major producers is zero because there are no leasehold costs included and major producers deplete on a cost basis. Independent producers deplete on a percentage basis and therefore have a value for the oil depletion allowance.

Earnings before interest and taxes (EBIT) in line 52 is defined as earnings before interest and ODA (line 50) minus the adjusted oil depletion allowance (line 51).

The figure in line 52 serves basis for the calculation of state taxes, shown in line 54. Federal taxes (line 53) are then calculated on the difference between EBIT and state taxes. Earnings after taxes are given in line 55.

Project cash flows, line 56, are estimated by adding noncash expenses, depreciation, and depletion back into earnings after taxes. The net cash flow for year 1 is $697, since both depreciation and depletion are zero.

The cash flows forecasted for the project may or may not be sufficient to justify continued operation. Since the capital costs are allocated on a per-barrel cost, it is likely that in the later stages of a well's production the revenue from oil and gas production will be insufficient to cover the increasing operating costs for produced water disposal. If net cash flow is equal to or less than zero in any given year, the project is assumed to shut down. The model prints a "1" in line 57 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 the fact that oil and gas are no longer being produced and sold. Lines 58 through 64 restate production volumes, revenues, and cash flow in the event of a shutdown; that is, production and revenues are set to zero after the project shuts down. Depreciation is also recalculated; the final year's capital expenditures are set to zero, and any depreciation remaining from previous capital expenditures is assumed to be taken as a tax deduction against the operator's income from other enterprises. Unexpended capitalized costs and surplus depreciation are summarized in lines 65 and 66 .

The production information for the second and third decades of operation are found in lines 67 through 75 and lines 107 through 115, respectively. The corresponding income statements are shown in lines 76 through 106 and lines 116 through 143.

C.2.3 Summary Statistics

To summarize the project's economics, all costs and revenues associated with the project from year 1 to its end are put in present value terms as of the base year, as well as totaled; see lines 144 through 183.

The present value of total company costs (line 157) is the sum of the present values of the parameters listed in lines 146 through 156, subtracting PV of surplus depreciation (line 145). This parameter provides a measure of the present value of net company resources expended in operation of the petroleum project.

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 158). 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 159).

The capital and the annual O&M costs for incremental pollution control of produced water effluents are given in terms of present value and are annualized over the economic lifetime of the well. The annualized cost is given in line 160. This is the annualized cost of the present value of the pollution control costs that were incorporated into the model on a per-barrel of produced water basis.

The capital and the annual O&M costs for incremental pollution control of produced water effluents are given in terms of present value and are annualized over the economic lifetime of the well. The annualized cost is given in line 160. This is the annualized cost of the present value of the pollution control costs that were incorporated into the model on a per-barrel of produced water basis.

Oil and gas production is also discounted so that they can be stated in present value equivalent terms (see lines 167 through 170). Corporate costs per barrel and corporate costs per Mcf are obtained by dividing the present value of the company costs by the present value equivalent of production (see lines 171 through 174).

The present value of social costs (lines 175 through 177) provides a measure of the value of net social resources expended in the development and operation of coastal 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 operating costs and investment costs. Social cost per unit of production is obtained by dividing the social cost by the present value equivalent of production (lines 178 through 181).

The number of years the project operates is shown in line 182. This number reflects the total number of years that well operates with a positive cash flow.

The net present value of the project, line 183, is calculated as:

$$
\begin{aligned}
\text{Net Present Value} &= \text{PV of Cash Inflows} - \text{PV of Cash Outflows} \\
&= \text{PV of Operating Cash Flows} \\
&\quad - \text{PV of Expensed Investment Cash Flows} \\
&\quad - \text{PV of Capitalized Costs} \\
&\quad - \text{PV of Leasehold Costs} \\
&\quad + \text{PV of Surplus Depreciation}
\end{aligned}
$$

A positive net present value is indicative of a profitable project at the assumed discount rate; that is, the project analyzed generates more revenue than would be generated by investing the capital in another project with an expected rate of return equal to the assumed discount rate.

FIGURE C-2
OPEN BAY/INDIVIDUAL PERMIT PRODUCTION LOSS MODEL

Run Date:	06-Sep-96							
(1) API Number	0							
(2) Project Type:	Existing Project							
(3) Real Discount Rate:	8%							
(4) Inflation Rate:	3%							
(5) Water:oil (bbl:bbl) or Water:gas (bbl:MMcf)	0.60							
(6) Oil/Gas Prod. Decline Rate/Year (%):	85%							
(7) Cost Escalator (%):	0.00%							
(8) Royalty Rate (%):	16.67%							
(9) Corp Structure (1-major/2-indep):	1							
(10) Federal Tax Rate (%):	34%							
(11) State Tax Rate (%):	8.00%							
(12) Average Depreciation Life (years):	7							
(13) Deprec. rate (each year):	14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%
(14) State Severance Tax Rate-Oil: (If Alaska enter 99)	12.50%							
(15) State Severance Tax Rate-Gas: (If Alaska enter 99)	4.05%							

PRODUCTION COSTS

Gas Only? (1=yes, 0=no):	0
Yrs Btwn Strt Dev & Strt Prod (<5):	1
(16) Number of Years at Peak Prod:	1
(17) Oil Peak Prod. Rate/Well(bb):	250
(18) Gas Peak Prod. Rate/Well(MMCF/D):	0.1
(19) Number of Producing Wells:	1
(20) Number of Wells Put in Service/Year:	1
(21) Price of Oil Per Barrel:	$18.00
(22) Price of Gas Per MCF:	$1.50
(23) Total Operating Costs ($000):	$40.00
(24) Water Disposal Cost per Barrel ($):	$0.35
(25) Days of Production Per Year:	365

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
OIL AND WATER PRODUCTION										
(26) Producing Wells in Service:	1	0	0	0	0					
(27) Barrels of Oil Per Day:	250	213	181	154	131	111	94	80	68	58
(28) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(29) Barrels of Oil Per Year:	91250	77563	65928	56039	47633	40488	34415	29253	24865	21135
(30) Price/Barrel of Oil:	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00
(31) Barrels of Water Per Day:	150	188	219	246	269	289	306	320	332	342
(32) Total Fluid Per Day:	400	400	400	400	400	400	400	400	400	400
GAS PRODUCTION										
(33) MMCF of Gas Per Day:	0	0	0	0	0	0	0	0	0	0
(34) MMCF of Gas Per Year:	37	31	26	22	19	16	14	12	10	8
(35) Price/MCF of Gas:	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
INCOME STATEMENT										
(36) Annual Oil Revenues ($000):	$1,643	$1,396	$1,187	$1,009	$857	$729	$619	$527	$448	$380
(37) Annual Gas Revenues ($000):	$55	$47	$40	$34	$29	$24	$21	$18	$15	$13
(38) Total Revenues ($000):	$1,697	$1,443	$1,226	$1,042	$886	$753	$640	$544	$462	$393
(39) Royalty Payments-Oil ($000):	$274	$233	$198	$168	$143	$121	$103	$88	$75	$63
(40) Royalty Payments-Gas ($000):	$9	$8	$7	$6	$5	$4	$3	$3	$2	$2
(41) Severance Taxes-Oil ($000):	$205	$175	$148	$126	$107	$91	$77	$66	$56	$48
(42) Severance Taxes-Gas ($000):	$2	$2	$2	$1	$1	$1	$1	$1	$1	$1
**** ELF for Alaska Severance Taxes-Oil:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
**** ELF for Alaska Severance Taxes-Gas:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(43) Net Revenues ($000):	$1,207	$1,026	$872	$741	$630	$535	$455	$387	$329	$280
(44) Total Operating Costs ($000):	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
(45) Expensed Poll.Cont.Cap.Costs ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(46) Poll.Con.Operating Costs ($000):	$19	$24	$28	$31	$34	$37	$39	$41	$42	$44
(47) Capitalized Costs ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(48) Adjstd Depreciation & Amort ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(49) Operating Earnings ($000):	$1,148	$962	$804	$670	$556	$459	$376	$306	$246	$196
(50) Earnings Before Interest and ODA:	$1,148	$962	$804	$670	$556	$459	$376	$306	$246	$196
(51) Adjsted Depletion Allowance:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(52) Earnings Before Interest and Taxes:	$1,148	$962	$804	$670	$556	$459	$376	$306	$246	$196
(53) Federal Tax (Earnings-State taxes):	$359	$301	$251	$209	$174	$143	$118	$96	$77	$61
(54) State Tax:	$92	$77	$64	$54	$44	$37	$30	$24	$20	$16
(55) Earnings Before Interest After Tax:	$697	$584	$488	$407	$337	$278	$228	$186	$150	$135
(56) Net Cash Flow:	$697	$584	$488	$407	$337	$278	$228	$186	$150	$135
(57) Shutoff?	1	1	1	1	1	1	1	1	1	1
(58) Actual Oil Prod./Year (Barrels):	91250	77563	65928	56039	47633	40488	34415	29253	24865	21135
(59) Actual Gas Prod./Year (MMCF):	37	31	26	22	19	16	14	12	10	8
(60) Actual Gross Revenues ($000):	$1,697	$1,443	$1,226	$1,042	$886	$753	$640	$544	$462	$393
(61) Actual Net Revenues ($000):	$1,207	$1,026	$872	$741	$630	$535	$455	$387	$329	$280
(62) Actual Net Cash Flow ($000):	$697	$584	$488	$407	$337	$278	$228	$186	$150	$135
(63) Actual Federal Taxes Paid ($000):	$359	$301	$251	$209	$174	$143	$118	$96	$77	$61
(64) Actual State Taxes Paid ($000):	$92	$77	$64	$54	$44	$37	$30	$24	$20	$16
(65) Capitalized Costs Not Expended:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(66) Surplus Depreciation:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
OIL AND WATER PRODUCTION										
(67) Barrels Oil Per Day:	49	42	36	30	26	22	19	16	13	11
(68) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(69) Barrels Oil Per Year:	17965	15270	12980	11033	9378	7971	6775	5759	4895	4161
(70) Price Per Barrel:	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00
(71) Barrels of Water Per Day:	351	358	364	370	374	378	381	384	387	389
(72) Total Fluid Per Day:	400	400	400	400	400	400	400	400	400	400
GAS PRODUCTION										
(73) MMCF Gas Per Day:	0	0	0	0	0	0	0	0	0	0
(74) MMCF Gas Per Year:	7	6	5	4	4	3	3	2	2	2
(75) Price Per MCF:	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
INCOME STATEMENT										
(76) Oil Revenues ($000):	$323	$275	$234	$199	$169	$143	$122	$104	$88	$75
(77) Gas Revenues ($000):	$11	$9	$8	$7	$6	$5	$4	$3	$3	$2
(78) Total Revenues ($000):	$334	$284	$241	$205	$174	$148	$126	$107	$91	$77
(79) Royalty Payments-Oil ($000):	$54	$46	$39	$33	$28	$24	$20	$17	$15	$12
(80) Royalty Payments-Gas ($000):	$2	$2	$1	$1	$1	$1	$1	$1	$0	$0
(81) Severance Taxes-Oil ($000):	$40	$34	$29	$25	$21	$18	$15	$13	$11	$9
(82) Severance Taxes-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
**** ELF for Alaska Severance Taxes-Oil:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
**** ELF for Alaska Severance Taxes-Gas:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(83) Net Revenues($000):	$238	$202	$172	$146	$124	$105	$90	$76	$65	$55
(84) Operating Costs:	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
(85) Expensed Poll.Cont.Cap.Costs ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(86) Pollution Control Operating Costs:	$45	$46	$47	$47	$48	$48	$49	$49	$49	$50
(87) For PV Poll. Control:	$45	$46	$47	$47	$48	$48	$49	$0	$0	$0
(88) Adjstd Depreciation & Amort ($000):	$0	$0	$0	$0	$0	$0	$0			
(89) Operating Earnings ($000):	$153	$116	$85	$59	$36	$17	$1	($13)	($25)	($35)
(90) Earnings Before Interest and ODA:	$153	$116	$85	$59	$36	$17	$1	($13)	($25)	($35)
(91) Adjsted Depletion Allowance:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(92) Earnings Before Interest and Taxes:	$153	$116	$85	$59	$36	$17	$1	($13)	($25)	($35)
(93) Federal Tax (Earnings-State taxes):	$48	$36	$27	$18	$11	$5	$0	($4)	($8)	($11)
(94) State Tax:	$12	$9	$7	$5	$3	$1	$0	($1)	($2)	($3)
(95) Earnings Before Interest After Tax:	$93	$71	$52	$36	$22	$10	$1	($8)	($15)	($24)
(96) Net Cash Flow:	$93	$71	$52	$36	$22	$10	$1	($8)	($15)	($24)
(97) Shutoff?	1	1	1	1	1	1	1	0	0	0
(98) Actual Oil Prod./Year (Barrels):	17965	15270	12980	11033	9378	7971	6775	0	0	0
(99) Actual Gas Prod./Year (MMCF):	7	6	5	4	4	3	3	0	0	0
(100) Actual Gross Revenues ($000):	$334	$284	$241	$205	$174	$148	$126	$0	$0	$0
(101) Actual Net Revenues ($000):	$238	$202	$172	$146	$124	$105	$90	$0	$0	$0
(102) Actual Net Cash Flow ($000):	$93	$71	$52	$36	$22	$10	$1	$0	$0	$0
(103) Actual Federal Taxes Paid ($000):	$48	$36	$27	$18	$11	$5	$0	$0	$0	$0
(104) Actual State Taxes Paid ($000):	$12	$9	$7	$5	$3	$1	$0	$0	$0	$0
(105) Capitalized Costs Not Expended:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(106) Surplus Depreciation:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
OIL AND WATER PRODUCTION										
(107) Barrels Oil Per Day:	10	8	7	6	5	4	4	3	3	2
(108) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(109) Barrels Oil Per Year:	3537	3006	2555	2172	1846	1569	1334	1134	964	819
(110) Price Per Barrel:	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00
(111) Barrels of Water Per Day:	390	392	393	394	395	396	396	397	397	398
(112) Total Fluid Per Day:	400	400	400	400	400	400	400	400	400	400
GAS PRODUCTION										
(113) MMCF Gas Per Day:	0	0	0	0	0	0	0	0	0	0
(114) MMCF Gas Per Year:	1	1	1	1	1	1	1	0	0	0
(115) Price Per MCF:	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
INCOME STATEMENT										
(116) Oil Revenues ($000):	$64	$54	$46	$39	$33	$28	$24	$20	$17	$15
(117) Gas Revenues ($000):	$2	$2	$2	$1	$1	$1	$1	$1	$1	$0
(118) Total Revenues ($000):	$66	$56	$48	$40	$34	$29	$25	$21	$18	$15
(119) Royalty Payments-Oil ($000):	$11	$9	$8	$7	$6	$5	$4	$3	$3	$2
(120) Royalty Payments-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(121) Severance Taxes-Oil ($000):	$8	$7	$6	$5	$4	$4	$3	$3	$2	$2
(122) Severance Taxes-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
**** ELF for Alaska Severance Taxes-Oil:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
**** ELF for Alaska Severance Taxes-Gas:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(123) Net Revenues($000):	$47	$40	$34	$29	$24	$21	$18	$15	$13	$11
(124) Operating Costs:	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
(125) Pollution Control Operating Costs:	$50	$50	$50	$50	$50	$51	$51	$51	$51	$51
(126) For PV Poll. Control:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(127) Adjstd Depreciation & Amort ($000):										
(128) Operating Earnings ($000):	($43)	($50)	($56)	($62)	($66)	($70)	($73)	($76)	($78)	($80)
(129) Earnings Before Interest and ODA:	($43)	($50)	($56)	($62)	($66)	($70)	($73)	($76)	($78)	($80)
(130) Adjsted Depletion Allowance:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(131) Earnings Before Interest and Taxes:	($43)	($50)	($56)	($62)	($66)	($70)	($73)	($76)	($78)	($80)
(132) Federal Tax (Earnings-State taxes):	($13)	($16)	($18)	($19)	($21)	($22)	($23)	($24)	($24)	($25)
(133) State Tax:	($3)	($4)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
(134) Earnings Before Interest After Tax:	($26)	($31)	($34)	($37)	($40)	($42)	($44)	($46)	($47)	($55)
(135) Net Cash Flow:	($26)	($31)	($34)	($37)	($40)	($42)	($44)	($46)	($47)	($55)
(136) Shutoff?	0	0	0	0	0	0	0	0	0	0
(137) Actual Oil Prod./Year (Barrels):	0	0	0	0	0	0	0	0	0	0
(138) Actual Gas Prod./Year (MMCF):	0	0	0	0	0	0	0	0	0	0
(139) Actual Gross Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(140) Actual Net Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(141) Actual Net Cash Flow ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(142) Actual Federal Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(143) Actual State Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

(144) PV of Net Cash Flows:	$2,732	(167) PV Equiv. of Oil Prod.(bb):		392,369
(145) PV of Surplus Depreciation:	$0	(168) PV Equiv. of Gas (MMCF):		157
		(169) PV Equiv. of Prod. (MMBTU):		2,435,983
(146) PV of Expensed Invest Cash Flows:	$0	(170) PV Barrels of Oil Equiv. (BOE):		419,997
(147) PV of Capitalized Costs:	$0	(171) Amortized Company Cost per MMBTU:		$1.73
(148) PV of Leasehold Cost:	$0	(172) Amortized Company Cost per bbl:		$10.44
(149) PV Poll. Cont. Costs:	$333	(173) Amortized Company Cost per MCF:		$0.74
(150) PV of Royalties - Oil:	$1,177	(174) Amortized Company Cost per BOE:		$10.03
(151) PV of Royalties - Gas:	$39			
(152) PV of Severance Taxes - Oil:	$883	(175) PV of Social Costs - Total:	$702	
(153) PV of Severance Taxes - Gas:	$10	(176) PV of Social Costs - Oil:	$679	
(154) PV of Operating Costs:	$369	(177) PV of Social Costs - Gas:	$23	
(155) PV of Federal Income Taxes:	$1,404	(178) Amortized Social Cost/MMBTU:	$0.29	
(156) PV of State Income Taxes:	$359	(179) Amortized Social Cost/bbl:	$1.73	
		(180) Amortized Social Cost/MCF:	$0.14	
(157) PV of Total Company Costs:	$4,215	(181) Amortized Social Cost/BOE:	$1.67	
(158) PV of Total Company Costs - Oil:	$4,098			
(159) PV of Total Company Costs - Gas:	$117	(182) Years of Production:	17	
(160) Annualized Poll.Cont.Costs:	$33	(183) Net Present Value of Project:		$2,732
(161) Severance Tax Total	$892			
(162) Severance Tax Plus State Income Tax (PV, Impacts on States)	$1,251			
(163) Total Oil Prod.(bb):	569,939			
(164) Total Gas (MMCF):	228			
(165) Total Prod. (MMBTU):	3,538,411			
(166) Total Barrels of Oil Equiv. (BOE):	610,071			