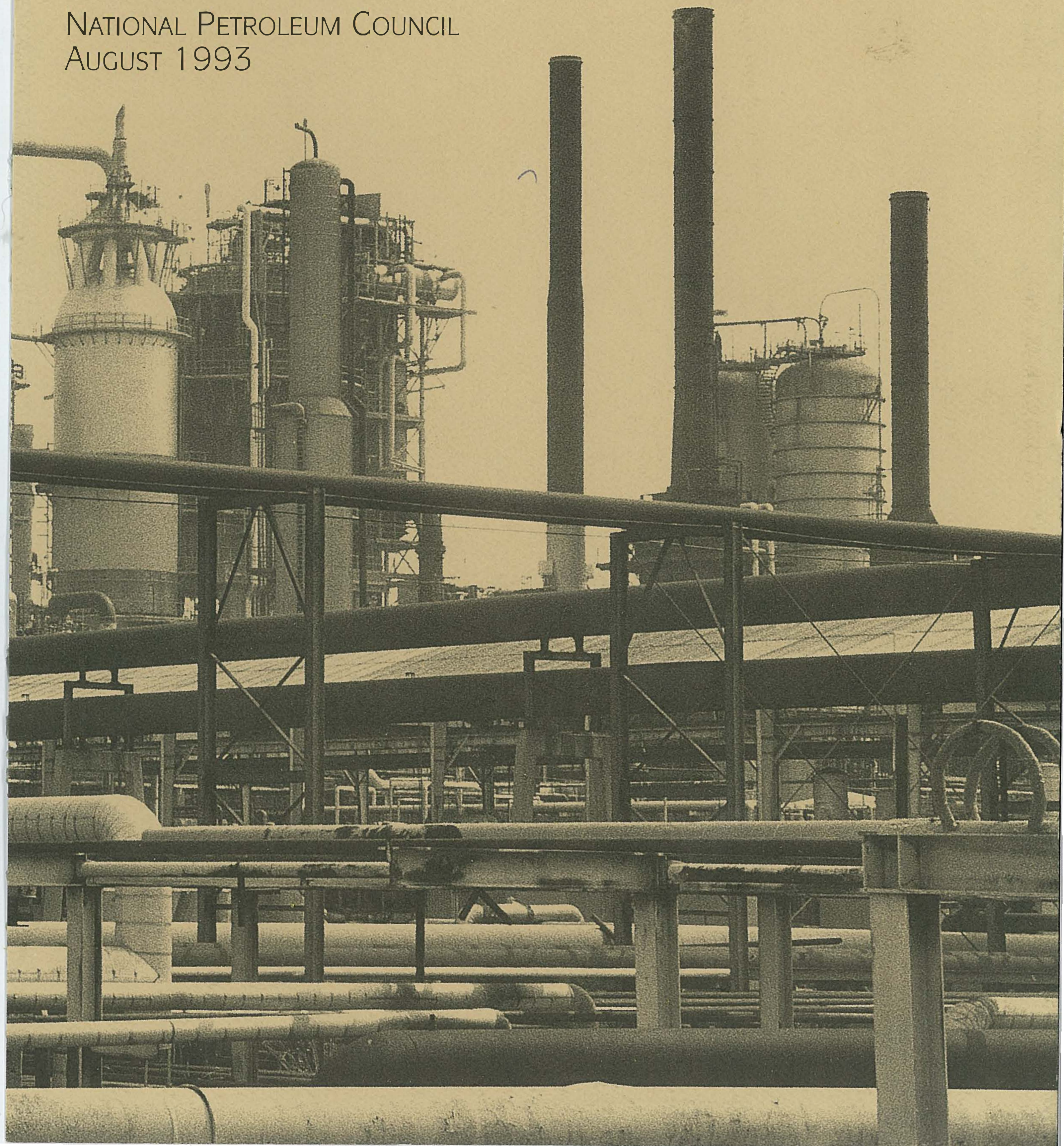
U.S. PETROLEUM REFINING

MEETING REQUIREMENTS FOR CLEANER FUELS AND REFINERIES

VOLUME III—FINANCIAL AND FACILITIES APPENDICES

NATIONAL PETROLEUM COUNCIL
AUGUST 1993



NATIONAL PETROLEUM COUNCIL

Ray L. Hunt, *Chairman*
Kenneth T. Derr, *Vice Chairman*
Marshall W. Nichols, *Executive Director*

U.S. DEPARTMENT OF ENERGY

Hazel R. O'Leary, *Secretary*

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to oil and natural gas or to the oil and gas industries.

Library of Congress Catalog Card Number: 93-86296

Printed in the United States of America

U.S. PETROLEUM REFINING

MEETING REQUIREMENTS FOR CLEANER FUELS AND REFINERIES

VOLUME III–FINANCIAL AND FACILITIES APPENDICES
NATIONAL PETROLEUM COUNCIL • AUGUST 1993

COMMITTEE ON REFINING
KENNETH T. DERR, CHAIRMAN

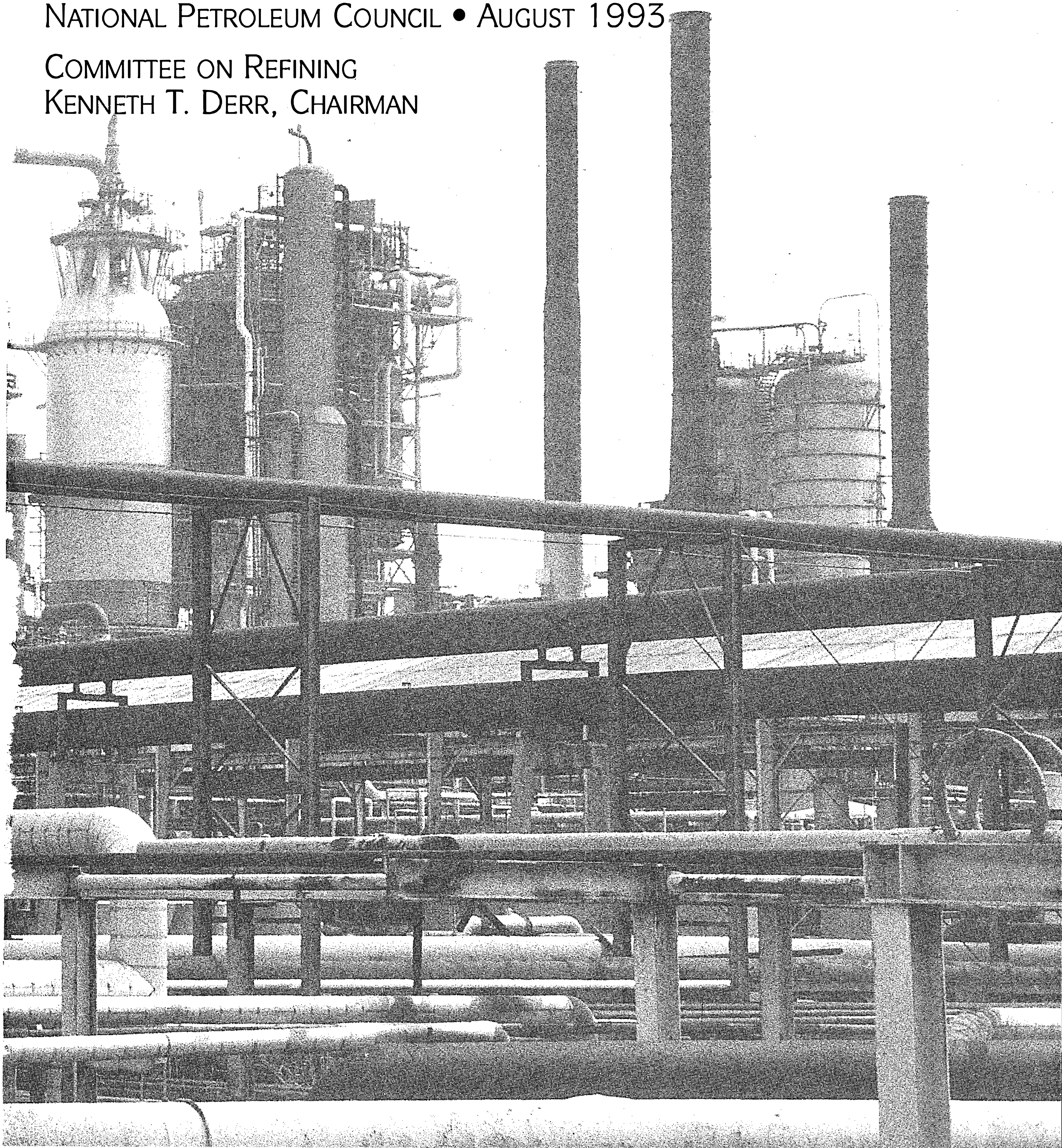


Table of Contents

APPENDIX J

FINANCIAL ANALYSIS

THIS APPENDIX CONTAINS SUPPORTING DATA FOR CHAPTER ONE, PRESENTED IN SECTIONS THAT CORRESPOND TO SECTION TITLES IN THE CHAPTER. THERE IS NO APPENDIX MATERIAL FOR SECTION I (INTRODUCTION AND SUMMARY) OF CHAPTER ONE.

Section II

Costs of Regulation

Table APP.J.II-1

A:\FRS\CAPEX.WK3

Capital Expenditures in U.S. Refineries
$ Million (Then Current Dollars)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
CAPITAL EXPENDITURES ($1990)										
Pollution Abatement (1)	848	962	630	388	348	495	514	526	436	917
Stationary Facilities (2)	150	150	150	150	150	542	963	960	385	299
Reformulated Gasoline										
Ultra Low Sulfur Diesel										
California Low Aromatics Diesel										
CARB 2 Gasoline										
All Other	6,402	7,775	5,169	4,157	3,625	1,974	1,461	1,362	2,654	2,942
TOTAL REFINING	7,400	8,887	5,949	4,695	4,123	3,011	2,938	2,848	3,475	4,158
MTBE-Ether (outside refineries)									400	400
CAPITAL EXPENDITURES (Current $)										
Pollution Abatement (1)	591	712	485	312	290	424	454	483	418	917
Stationary Facilities (2)	105	111	116	121	125	464	851	881	369	299
Reformulated Gasoline										
Ultra Low Sulfur Diesel										
California Low Aromatics Diesel										
CARB 2 Gasoline										
All Other	4,462	5,756	3,982	3,342	3,023	1,690	1,291	1,250	2,544	2,942
TOTAL REFINING	5,158	6,579	4,583	3,775	3,438	2,578	2,596	2,614	3,331	4,158
MTBE-Ether (outside refineries)	0	0	0	0	0	0	0	0	417	400
Department of Commerce Data										
MA-200 Pollution Abatement (sic 29)	591	712	485	312	290	424	454	483	418	917
MA-200 Total New Capital (sic29)	5,158	6,579	4,583	3,775	3,438	2,578	2,596	2,614	3,331	4,158
NPC Survey of Capital Expenditures										
to Meet Environmental Regulations (3)						888	1,305	1,364	787	1,216
GNP Deflator (4)	78.9	83.8	87.2	91.0	94.4	96.9	100.0	103.9	108.5	113.2
Current $ escalator (4% after 1990)										100.0

(1) Source: Department of Commerce Reports (MA-200) for 1988-1991.
No survey was taken in 1987. Values shown are the average of 1986 and 1988.
(2)National Petroleum Council Refining Study estimates from Chapter 2.
(3) from Chapter 2,Table 2.III-1
(4) Department of Commerce Gross Domestic Product deflator

Table APP.J.II-1 (Continued)

Capital Expenditures in U.S. Refineries
$ Million (Then Current Dollars)

CAPITAL EXPENDITURES ($1990)	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2010
Pollution Abatement (1)											
Stationary Facilities (2)	1,400	2,800	2,800	2,800	2,800	2,040	2,040	2,040	2,040	2,040	1,350
Reformulated Gasoline	500	500	1,500	1,000	1,000	500	500	500	500	500	
Ultra Low Sulfur Diesel	0	1,200	1,200								
California Low Aromatics Diesel		500	500								
CARB 2 Gasoline				1,650	1,650	0					
All Other	3,767	2,000	2,000	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
TOTAL REFINING	5,667	7,000	8,000	6,950	6,950	4,040	4,040	4,040	4,040	4,040	2,850
MTBE-Ether (outside refineries)	1,000	1,000	1,000	1,000	1,000	1,100	1,100	1,100	1,100	1,000	0
CAPITAL EXPENDITURES (Current $)											
Pollution Abatement (1)	0	0	0	0	0	0	0	0	0	0	0
Stationary Facilities (2)	1,456	3,030	3,150	3,276	3,408	2,583	2,687	2,795	2,907	3,023	2,961
Reformulated Gasoline	520	541	1,688	1,170	1,217	633	659	685	713	741	0
Ultra Low Sulfur Diesel	0	1,298	1,350	0	0	0	0	0	0	0	0
California Low Aromatics Diesel	0	541	563	0	0	0	0	0	0	0	0
CARB 2 Gasoline	0	0	0	1,931	2,008	0	0	0	0	0	0
All Other	3,920	2,164	2,250	1,755	1,826	1,899	1,976	2,055	2,138	2,223	3,290
TOTAL REFINING	5,896	7,574	9,001	8,132	8,459	5,115	5,322	5,535	5,758	5,987	6,251
MTBE-Ether (outside refineries)	962	924	889	855	822	869	835	803	772	675	0
Department of Commerce Data											
MA-200 Pollution Abatement (sic 29)	1,463										
MA-200 Total New Capital (sic29)	5,896										
NPC Survey of Capital Expenditures to Meet Environmental Regulations (3)											
GNP Deflator (4)	117.8										
Current $ escalator (4% after 1990)	104.0	108.2	112.5	117.0	121.7	126.6	131.7	137.0	142.5	148.2	219.3

(1) Source: Department of Commerce Reports (MA-200) for 1988-1991.
No survey was taken in 1987. Values shown are the average of 1986 and 1988.
(2)National Petroleum Council Refining Study estimates from Chapter 2.
(3) from Chapter 2,Table 2.III-1
(4) Department of Commerce Gross Domestic Product deflator

Table APP.J.II-1 (Continued)

Capital Expenditures in U.S. Refineries
$ Million (Then Current Dollars)

	1981-1990		1991-1995		1996-2000		1991-2000		2001-2010	
CAPITAL EXPENDITURES ($1990)	Total	Average	Total	Average	Total	Average	Total	Average	Total	Average
Pollution Abatement (1)	6,064	606	0	0	0	0	0	0	0	0
Stationary Facilities (2)	3,899	390	12,600	2,520	10,200	2,040	22,800	2,280	13,500	1,350
Reformulated Gasoline	0	0	4,500	900	2,500	500	7,000	700	0	0
Ultra Low Sulfur Diesel	0	0	2,400	480	0	0	2,400	240	0	0
California Low Aromatics Diesel	0	0	1,000	200	0	0	1,000	100	0	0
CARB 2 Gasoline	0	0	3,300	660	0	0	3,300	330	0	0
All Other	37,521	3,752	10,767	2,153	7,500	1,500	18,267	1,827	15,000	1,500
TOTAL REFINING	47,484	4,748	34,567	6,913	20,200	4,040	54,767	5,477	28,500	2,850
MTBE-Ether (outside refineries)	800	80	5,000	1,000	5,400	1,080	10,400	1,040		
CAPITAL EXPENDITURES (Current $)							Total	Average	Total	Average
Pollution Abatement (1)	5,086	509	0	0	0	0	0	0	0	0
Stationary Facilities (2)	3,442	344	14,320	2,864	13,995	2,799	28,315	2,832	24,981	2,498
Reformulated Gasoline	0	0	5,136	1,027	3,431	686	8,567	857	0	0
Ultra Low Sulfur Diesel	0	0	2,648	530	0	0	2,648	265	0	0
California Low Aromatics Diesel	0	0	1,104	221	0	0	1,104	110	0	0
CARB 2 Gasoline	0	0	3,939	788	0	0	3,939	394	0	0
All Other	30,282	3,028	11,915	2,383	10,291	2,058	22,206	2,221	27,757	2,776
TOTAL REFINING	38,810	3,881	39,062	7,812	27,717	5,543	66,779	6,678	52,739	5,274
MTBE-Ether (outside refineries)	817	82	4,452	890	3,954	791	8,406	841		
Department of Commerce Data										
MA-200 Pollution Abatement (sic 29)	5,086	509								
MA-200 Total New Capital (sic29)	38,810	3,881								
NPC Survey of Capital Expenditures to Meet Environmental Regulations (3)										
GNP Deflator (4)		95.8								
Current $ escalator (4% after 1990)		100.0								

(1) Source: Department of Commerce Reports (MA-200) for 1988-1991.
No survey was taken in 1987. Values shown are the average of 1986 and 1988.
(2)National Petroleum Council Refining Study estimates from Chapter 2.
(3) from Chapter 2,Table 2.III-1
(4) Department of Commerce Gross Domestic Product deflator

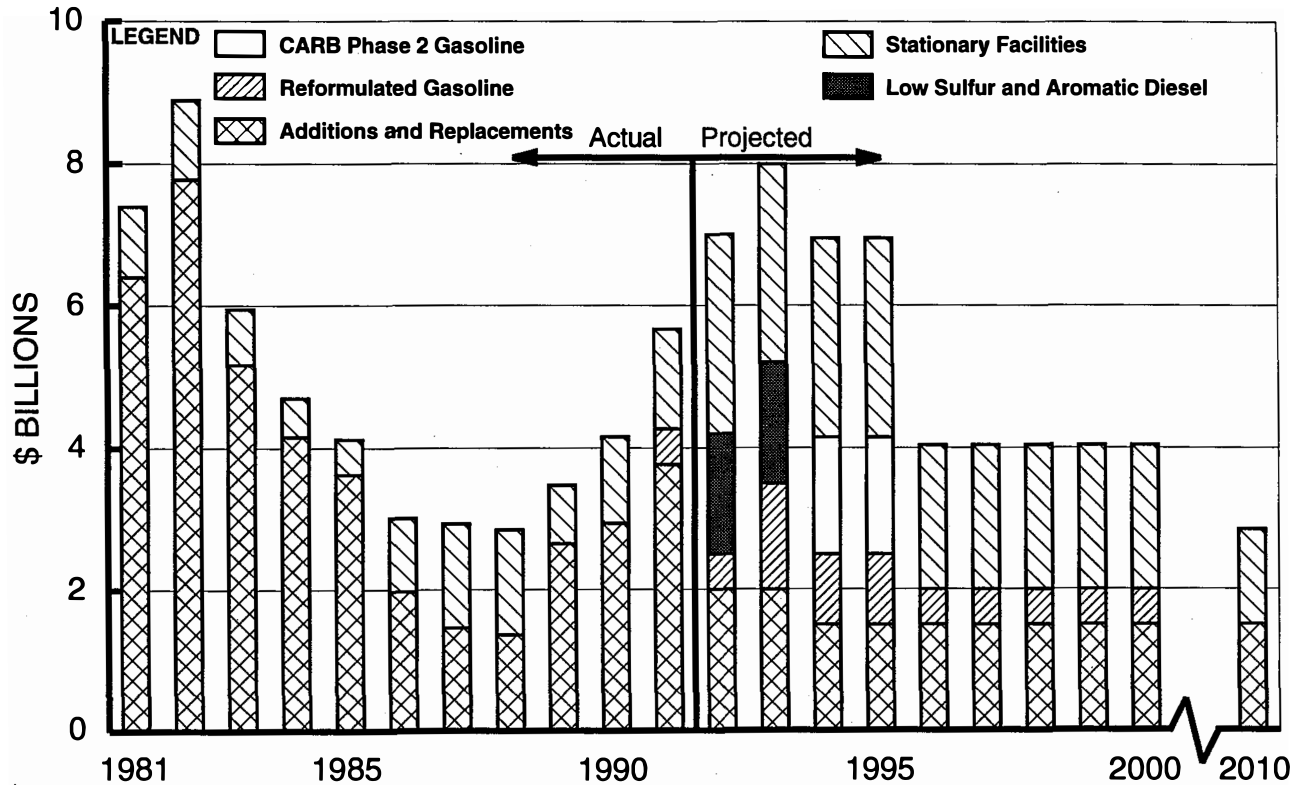


Figure APP. J.II-1. U.S. Refining Industry Capital Expenditures (1990 Dollars).

Historical Values taken from Department of Commerce report MA—200. No survey taken in 1987. Value shown is 1986 and 1988 average.

CARB = California Air Resources Board

GACOST.WK3

Table APP.J.II-2

U.S. Refinery Facilities Pollution Abatement Gross Annual Costs
$ Million (1990 Dollars)

Gross Annual Costs ($ 1990 millions)	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Historical Pollution Abatement (MA-200)	2,418	2,433	2,458	2,592	2,474	2,343	2,270	2,185	2,264	2,705
New Environmental Facilities O&M Cost										
New One Time Costs										
New Depreciation										
Added Pollution Abatement Costs	2,418	2,433	2,458	2,592	2,474	2,343	2,270	2,185	2,264	2,705
Cost of Capital (net of depreciation)										
Increase in Product Revenues Needed	2,418	2,433	2,458	2,592	2,474	2,343	2,270	2,185	2,264	2,705
Pollution Abatement GAC,$/Bbl. Output	$0.45	$0.48	$0.49	$0.50	$0.48	$0.43	$0.41	$0.39	$0.40	$0.47
Pollution Abatement GAC,CPG MJD	1.6	1.6	1.6	1.6	1.6	1.4	1.4	1.3	1.3	1.6
Price Needed w/cost of capital,CPG MJD	1.6	1.6	1.6	1.6	1.6	1.4	1.4	1.3	1.3	1.6
Increase Over 1989 Base,CPG MJD									Base	0.3
Gross Annual Costs ($ millions current)										
Historical Pollution Abatement (MA-200)	1,686	1,801	1,894	2,084	2,063	2,005	2,005	2,006	2,170	2,705
New Environmental Facilities O&M Cost										
New One Time Costs										
New Depreciation										
Added Pollution Abatement Costs	1,686	1,801	1,894	2,084	2,063	2,005	2,005	2,006	2,170	2,705
Cost of Capital (net of depreciation)										
Increase in Product Revenues Needed	1,686	1,801	1,894	2,084	2,063	2,005	2,005	2,006	2,170	2,705
Pollution Abatement GAC,$/Bbl. Output	$0.31	$0.35	$0.38	$0.40	$0.40	$0.37	$0.36	$0.36	$0.38	$0.47
Pollution Abatement GAC,CPG MJD	1.1	1.2	1.3	1.3	1.3	1.2	1.2	1.2	1.3	1.6
Price Needed w/cost of capital,CPG MJD	1.1	1.2	1.3	1.3	1.3	1.2	1.2	1.2	1.3	1.6
Increase Over 1989 Base,CPG MJD									Base	0.3
U.S. Refining Industry										
Total Output,MBPCD	14,661	14,008	13,694	14,270	14,190	14,927	15,085	15,426	15,655	15,911
Mogas,Jet,Kerosene and Distillate,MBPCD	9,980	9,930	9,820	10,260	10,300	10,840	10,910	11,190	11,260	11,370
Depreciation factor (book) =	0.0625									
EBIDT on investment factor =	0.1720									

Table APP.J.II-2 (Continued)

U.S. Refinery Facilities Pollution Abatement Gross Annual Costs
$ Million (1990 Dollars)

Gross Annual Costs ($ 1990 millions)	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2010
Historical Pollution Abatement (MA-200)											
New Environmental Facilities O&M Cost	2,239	2,250	2,750	3,250	3,750	4,220	4,680	5,150	5,610	6,080	7,180
New One Time Costs	500	1,000	1,000	1,000	1,000	260	260	260	260	260	120
New Depreciation	44	182	369	557	744	902	1,029	1,157	1,284	1,412	2,319
Added Pollution Abatement Costs	2,783	3,432	4,119	4,807	5,494	5,382	5,969	6,567	7,154	7,752	9,619
Cost of Capital (net of depreciation)	77	318	647	975	1,304	1,580	1,803	2,026	2,250	2,473	4,063
Increase in Product Revenues Needed	2,860	3,750	4,766	5,782	6,798	6,961	7,772	8,593	9,404	10,225	13,682
Pollution Abatement GAC,$/Bbl. Output	$0.48	$0.59	$0.71	$0.83	$0.95	$0.93	$1.03	$1.13	$1.23	$1.33	$1.66
Pollution Abatement GAC,CPG MJD	1.6	2.0	2.4	2.8	3.1	3.1	3.4	3.8	4.1	4.4	5.5
Price Needed w/cost of capital,CPG MJD	1.6	2.1	2.7	3.3	3.9	4.0	4.5	4.9	5.4	5.8	7.8
Increase Over 1989 Base,CPG MJD	0.3	0.8	1.4	2.0	2.6	2.7	3.2	3.6	4.1	4.5	6.5
Gross Annual Costs ($ millions current)											
Historical Pollution Abatement (MA-200)											
New Environmental Facilities O&M Cost	2,329	2,434	3,093	3,802	4,562	5,340	6,159	7,048	7,985	9,000	15,730
New One Time Costs	520	1,082	1,125	1,170	1,217	329	342	356	370	385	263
New Depreciation	74	221	428	644	867	1,062	1,227	1,398	1,576	1,761	3,704
Added Pollution Abatement Costs	2,923	3,737	4,647	5,615	6,646	6,731	7,727	8,802	9,931	11,146	19,697
Cost of Capital (net of depreciation)	130	388	751	1,127	1,519	1,861	2,149	2,449	2,761	3,085	6,489
Increase in Product Revenues Needed	3,053	4,125	5,397	6,743	8,166	8,591	9,876	11,250	12,691	14,231	26,186
Pollution Abatement GAC,$/Bbl. Output	$0.50	$0.64	$0.80	$0.97	$1.15	$1.16	$1.33	$1.52	$1.71	$1.92	$3.40
Pollution Abatement GAC,CPG MJD	1.7	2.1	2.7	3.2	3.8	3.8	4.4	5.0	5.7	6.4	11.3
Price Needed w/cost of capital,CPG MJD	1.8	2.4	3.1	3.9	4.7	4.9	5.7	6.4	7.3	8.1	15.0
Increase Over 1989 Base,CPG MJD	0.5	1.1	1.8	2.6	3.4	3.6	4.4	5.1	6.0	6.8	13.7
U.S. Refining Industry											
Total Output,MBPCD	15,872	15,872	15,872	15,872	15,872	15,872	15,872	15,872	15,872	15,872	15,872
Mogas,Jet,Kerosene and Distillate,MBPCD	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380
Depreciation factor (book) =	0.0625										
EBIDT on investment factor =	0.1720										

Table APP.J.II-2 (Continued)

GACOST.WK3

U.S. Refinery Facilities Pollution Abatement Gross Annual Costs

$ Million (1990 Dollars)

	1981-1985		1986-1990		1991-1995		1996-2000		2000-2010	
Gross Annual Costs ($ 1990 millions)	Total	Average	Total	Average	Total	Average	Total	Average	Total	Average
Historical Pollution Abatement (MA-200)	12,375	2,475	11,766	2,353	0	0	0	0	0	0
New Environmental Facilities O&M Cost	0	0	0	0	14,239	2,848	25,740	5,148	66,850	6,685
New One Time Costs	0	0	0	0	4,500	900	1,300	260	1,200	120
New Depreciation	0	0	0	0	1,895	379	5,783	1,157	19,107	1,911
Added Pollution Abatement Costs	12,375	2,475	11,766	2,353	20,634	4,127	32,823	6,565	87,787	8,779
Cost of Capital (net of depreciation)	0	0	0	0	3,321	664	10,132	2,026	33,476	3,348
Increase in Product Revenues Needed	12,375	2,475	11,766	2,353	23,955	4,791	42,955	8,591	121,264	12,126
Pollution Abatement GAC,$/Bbl. Output		$0.48		$0.42		$0.71		$1.13		$1.50
Pollution Abatement GAC,CPG MJD		1.6		1.4		2.4		3.8		5.0
Price Needed w/cost of capital,CPG MJD		1.6		1.4		2.7		4.9		6.8
Increase Over 1989 Base,CPG MJD										
Gross Annual Costs ($ millions current)										
Historical Pollution Abatement (MA-200)	9,527	1,905	10,891	2,178	0	0	0	0	0	0
New Environmental Facilities O&M Cost	0	0	0	0	16,220	3,244	35,531	7,106	127,013	12,701
New One Time Costs	0	0	0	0	5,113	1,023	1,782	356	2,629	263
New Depreciation	0	0	0	0	2,235	447	7,023	1,405	28,296	2,830
Added Pollution Abatement Costs	9,527	1,905	10,891	2,178	23,568	4,714	44,336	8,867	158,486	15,849
Cost of Capital (net of depreciation)	0	0	0	0	3,916	783	12,304	2,461	49,574	4,957
Increase in Product Revenues Needed	9,527	1,905	10,891	2,178	27,484	5,497	56,640	11,328	208,060	20,806
Pollution Abatement GAC,$/Bbl. Output		$0.37		$0.39		$0.81		$1.53		$2.66
Pollution Abatement GAC,CPG MJD		1.2		1.3		2.7		5.1		8.9
Price Needed w/cost of capital,CPG MJD		1.2		1.3		3.2		6.5		11.6
Increase Over 1989 Base,CPG MJD										
U.S. Refining Industry										
Total Output,MBPCD		14,165		15,401		15,872		15,872		15,872
Mogas,Jet,Kerosene and Distillate,MBPCD		10,058		11,114		11,380		11,380		11,380
Depreciation factor (book) =	0.0625									
EBIDT on investment factor =	0.1720									

Table APP.J.II-2 (Continued)

GACOST.WK3

U.S. Refinery Facilities Pollution Abatement Gross Annual Costs
$ Million (1990 Dollars)

Capital Expenditures ($1990)	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
Historical Pollution Abatement	847	962	630	388	348	496	513	526	436	917	806
Future Eviornmental Facilities											600
Capital Expenditures ($ current)											
Historical Pollution Abatement	591	712	485	312	290	424	454	483	418	917	839
Future Eviornmental Facilities											624
Bureau of Census Report (MA-200)											
Pollution Abatement Capital Ex. (SIC 29)	591	712	485	312	290	424	454	483	418	917	1,463
Total New Capital Expenditures (SIC 29)	5,158	6,579	4,583	3,775	3,438	2,578	2,596	2,614	3,331	4,158	5,896
GNP Deflator (1)	78.9	83.8	87.2	91.0	94.4	96.9	100.0	103.9	108.5	113.2	117.8
Current $ inflation (4% after 1990)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	104.0

(1) Dept. of Commerce Gross Domestic Product deflator

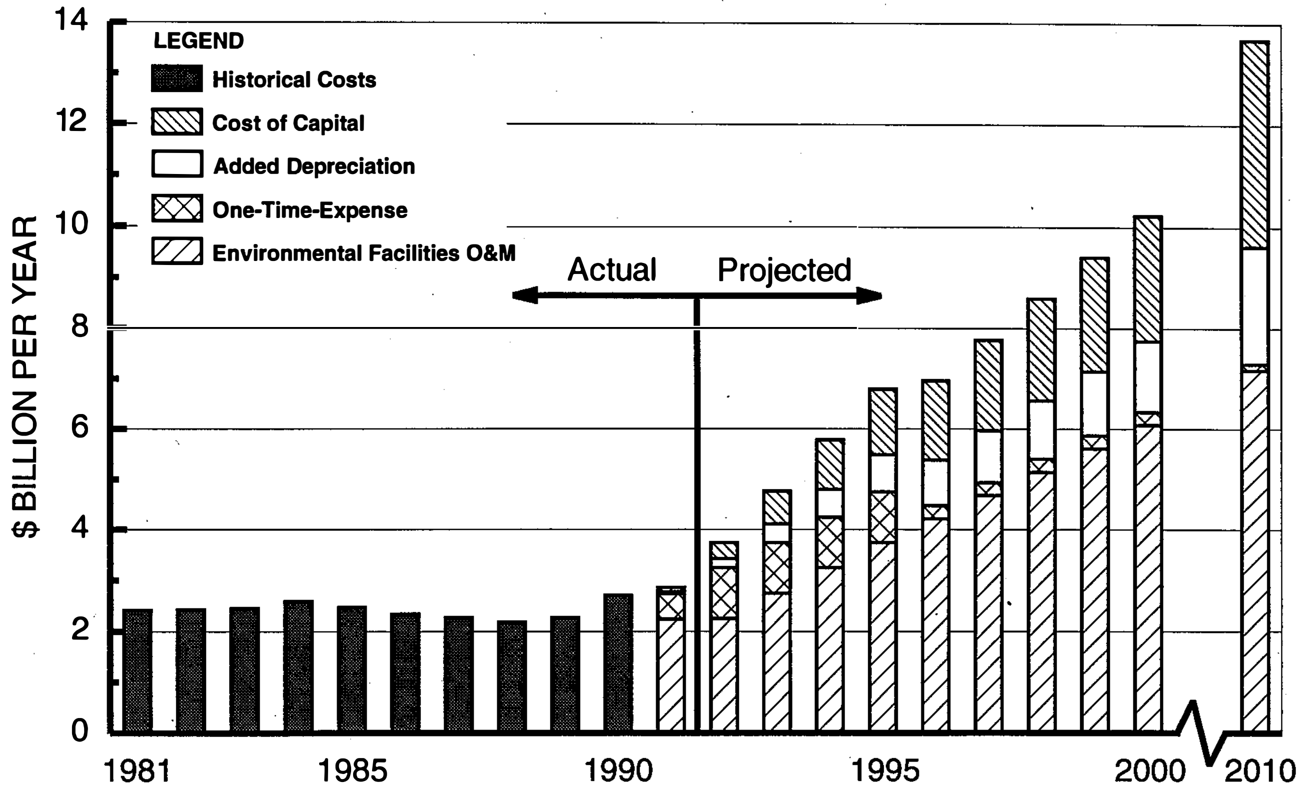


Figure APP. J.II-2. Stationary Source Costs for U.S. Refinery Facilities (1990 Dollars).

Historical costs for 1981-1991 taken from Department of Commerce report MA—200 do not include cost of capital. No survey was taken in 1987—value shown is 1986 and 1987 average. Cost of capital equivalent to 10 percent discounted cash flow rate of return after 1991 is shown for the projected new environmental capital expenditures.

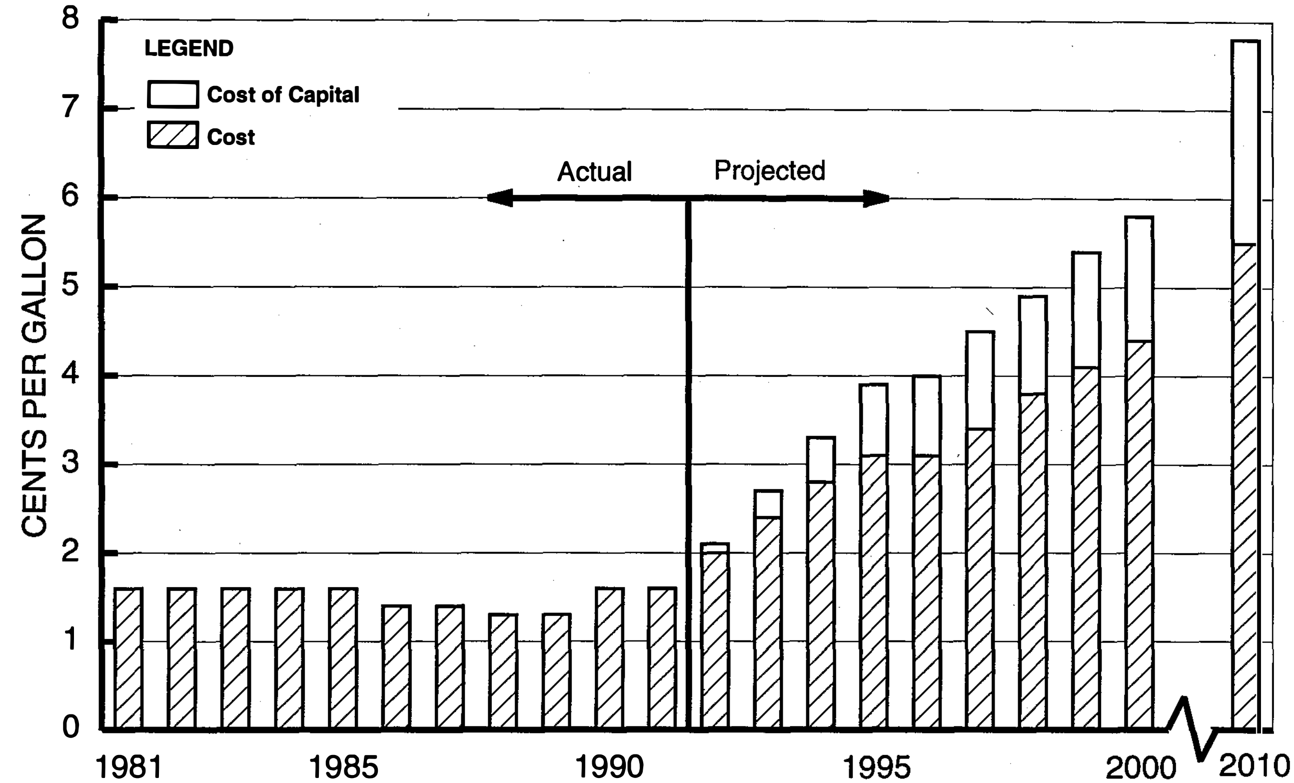


Figure APP. J.II-3. U.S. Refinery Facilities Stationary Source Costs Cents per Gallon, Gasoline, Jet Fuel, and Distillate (1990 Dollars).

Historical costs for 1981-1991 taken from Department of Commerce report MA—200 do not include cost of capital. Forecast costs include cost of capital sufficient for a 10 percent discounted cash flow rate of return.

PQCOSTS.WK3

Table APP.J.II-3

Annual Average Product Quality Costs
$ Million Per Year (1990 Dollars)

PRODUCT	Refinery Investment $ MM	Quantity Produced M B/D	Operating Costs & Product Upgrade CPG	Operating Costs & Product Upgrade $MM/YR	Book Depreciation $MM/YR	(1) Capital Charge $MM/YR	Total Costs CPG	Total Costs $MM/YR
Low Sulfur Diesel	2,400	1,324	1.8	358	150	263	3.8	771
Calif. Low Aromatics Diesel	1,000	247	9.9	376	63	110	14.5	549
SF Reformulated Gasoline - 9 cities	4,500	2,153	2.5	810	281	493	4.8	1,584
Calif. CARB2 Gasoline	3,300	911	10.1	1,416	206	361	14.2	1,983
CM RFG Phase 2 @ full opt-in	7,000	3,592	4.2	2,319	438	767	6.4	3,524

Schedule of Cost Increases	1993	1994	1995	1996	1997	1998	1999	2000	2010
Low Sulfur Diesel	193	771	771	771	771	771	771	771	771
CARB Low Aromatics Diesel	137	549	549	549	549	549	549	549	549
Reformulated Gasoline			1,584	1,972	2,360	2,748	3,136	3,524	3,524
CARB 2 Gasoline				1,983	1,983	1,983	1,983	1,983	1,983
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Product Quality Cost Increases	330	1,320	2,904	5,275	5,663	6,051	6,439	6,827	6,827

Earnings before depreciation & tax= 0.1720
Depreciation factor = 0.0625

(1) EBIT net of depreciation sufficient to earn a 10% DCF rate of return.

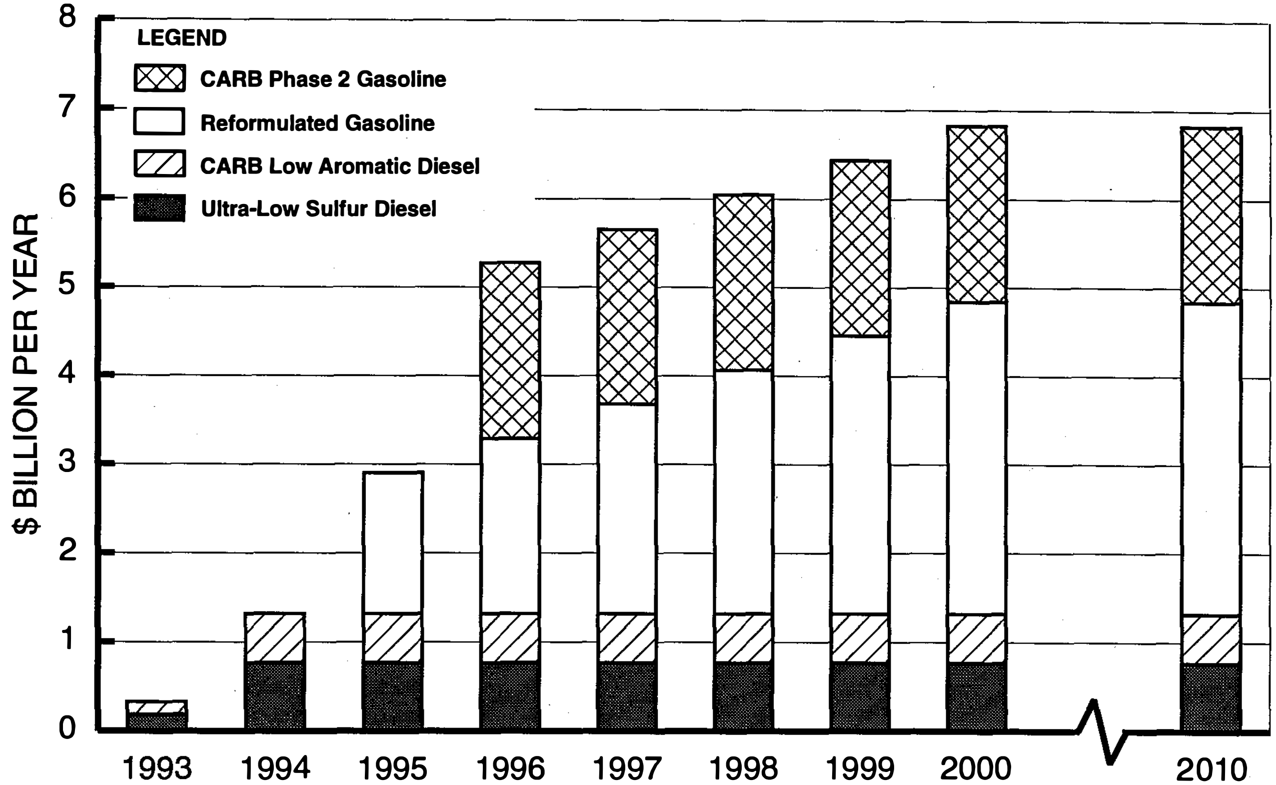


Figure APP. J.II-4. U.S. Refinery Product Quality Cost Increases (1990 Dollars).

Includes cost of capital on new capital expenditures at 10 percent discounted cash flow rate of return.
CARB = California Air Resources Board
1993, 1994 oxygenated gasoline costs not developed.

Historical Environmental Expenditures

The U.S. Department of Commerce, Bureau of the Census, has surveyed all U.S. industries for pollution abatement costs and expenditures annually for some time. Response to Form MA-200 is required by Title 13 of U.S. legal code for all manufacturing establishments with 20 employees or more. The purpose of the questionnaire is to collect total expenditures made by industry to abate pollution emissions. The survey covers current operating costs and capital expenditures made to reduce pollution in its air, water, or solid forms. Pollution abatement means the reduction or elimination of pollutants emitted from properties or activities. Pollution abatement includes prevention, treatment, and recycling. Treatment refers to the wide variety of techniques used to cool, detoxify, decompose, and separate-to-store or ameliorate.

Annual operating costs and expenses include all costs and expenses to operate and maintain plant and equipment that abate air or water pollutants and for solid waste management. This includes services provided by private contractor for solid waste collection/disposal. All pollution abatement equipment and processes in operation for the year are included regardless of the year that the equipment was installed.

These costs are included:

- Operation and maintenance of plant and equipment.
- Depreciation (or amortization) due to usage of plant and equipment.
- Materials, leasing of equipment, parts, and direct labor.
- Fuel and power as well as any increased costs due to increased consumption.
- Services provided by private contractors.
- Payments to governmental units for sewage service, including charges included in local tax bills, payments for overstrength effluent charges, and sewer district tax assessments.
- Payments to governmental units for municipal solid waste collection and disposal services.

Costs that are NOT included are expenditures for research and development, health and safety expenditures, and interest for financing pollution abatement capital expenditures. The costs are not adjusted for recovery through abatement activities such as the value of materials or energy reclaimed through the abatement activity.

Pollution Abatement Capital Expenditures (PACE) for Petroleum Manufacturing (SIC 29) have been fairly steady, averaging $460 million (then current dollars) per year from 1973 through 1989. Refining capital expenditures for pollution abatement increased sharply to $917 million in 1990 and to $1.41 billion in 1991 (Figure APP.J.II-5).

Gross Annual Costs (GAC) have increased at a more noticeable rate from $338 million in 1973 to $2.08 billion in 1984 (Figure APP.J.II-6). For the next five years, however, annual costs were relatively unchanged (although 1987 was not surveyed). Then, annual costs shot up to $2.7 billion in 1990 and to $2.85 billion in 1991.

The American Petroleum Institute has also been surveying its members for environmental protection expenditures since 1966. Their survey includes exploration and production, transportation, and marketing, as well as manufacturing operations. For purposes of this study, only the manufacturing data have been used. The same general format has been used in all the API surveys for comparability; however, the annual reports have slightly different reporting bases. The API did not extrapolate the survey data to 100 percent of the U.S. refining industry capacity until the 1990 report, although the refining capacity of the survey respondents was published for most years. (The API survey was suspended from 1985 through 1989.)

For improved comparability to the Census Bureau report, the API data were extrapolated to the U.S. refining industry total for this analysis.

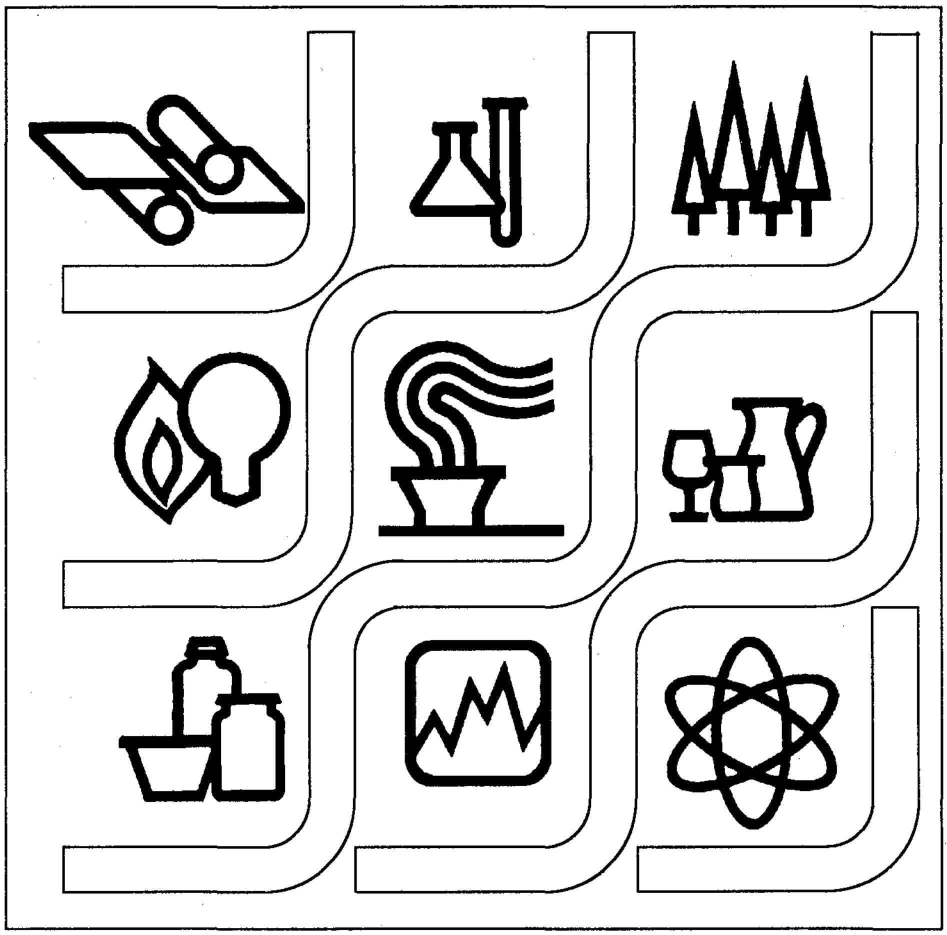
The API and NPC surveys mirror the data from the Census Bureau in that environmental capital expenditures show a dramatic increase in 1990 and 1991. Annual costs in the API survey rose faster than in the Census Bureau survey, but are in very close agreement for 1990 and 1991. Details of these sources of environmental costs are found in Table APP.J.II-2.

CURRENT INDUSTRIAL REPORTS

Pollution Abatement Costs and Expenditures, 1991

MA200(91)-1

Issued January 1993



U.S. Department of Commerce
Ronald H. Brown, Secretary
John Rollwagen, Deputy Secretary

Economics and Statistics Administration
Jeffrey Mayer, Acting Under Secretary

BUREAU OF THE CENSUS
Harry A. Scarr, Acting Director

Economics and Statistics Administration
Jeffrey Mayer, Acting Under Secretary for Economic Affairs

BUREAU OF THE CENSUS
Harry A. Scarr, Acting Director

Charles A. Waite, Associate Director for Economic Programs

INDUSTRY DIVISION
John H. Berry, Acting Chief

SUGGESTED CITATION

U.S. Bureau of the Census,
Pollution Abatement Costs and Expenditures, 1991 MA200(91)-1,
U.S. Government Printing Office, Washington, DC 1993.

For sale by Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402.

Appendix A. Pollution Abatement Form and Instructions (Form MA-200)

OMB NO. 0607-0176: Approval Expires 10/31/92

NOTICE – Response to this inquiry is **required by law (title 13, U.S. Code).** By section 9 of the same law, your report to the Census Bureau is **confidential**. It may be seen only by sworn Census employees and may be used only for statistical purposes. The law also provides that copies retained in your files are **immune from legal process.**

FORM **MA-200**
(0-09-91)

U.S. DEPARTMENT OF COMMERCE
BUREAU OF THE CENSUS

SURVEY OF POLLUTION ABATEMENT COSTS AND EXPENDITURES

In correspondence pertaining to this report refer to this **CENSUS FILE NUMBER (11 digits)**

RECODE	ADDRESS	EXTRA COPY	FOLLOWUP
TAB NUMBER		INDUSTRY	
WEIGHT	TE	EI	
AREA		PPN	

CENSUS USE ONLY

YOUR FILE COPY
(Please correct any errors in name, address, and ZIP Code)

RETURN COMPLETED FORM TO

Bureau of the Census
1201 East 10th Street
Jeffersonville, IN 47132-0001

Name of person who prepared or certified the prior year's report

This report is required only for the establishment specified in the address block of the report form. **DO NOT COMBINE** with other establishments in your company even though operations may jointly use the same pollution abatement facilities. When this occurs, apportion the expenditures and cost according to the rate of pollution abatement equipment utilization or the relative amounts of pollutants produced.

Item 1A — OPERATIONAL STATUS

Mark (X) ONE box which best describes this establishment at the end of

111 ☐ In operation
112 ☐ Temporarily idle ....
113 ☐ Sold or leased to another company — *Report new owner or operator in item 1B* ....
114 ☐ Permanently ceased operations ....

Give date Mo. | Yr.

Item 1B — NEW OWNER OR OPERATOR

121 Name

122 Number and street

123 City | 124 State | 125 ZIP Code

126 Employer Identification Number ⟶

IMPORTANT — *PLEASE READ INSTRUCTIONS AND DEFINITIONS BEFORE COMPLETING FORM*

Item 2 — IF THIS ESTABLISHMENT HAD NO OPERATING COSTS, PAYMENTS TO GOVERNMENT OR CAPITAL EXPENDITURES

Mark (X) in box for appropriate reason, ***complete Item 9 and return form.***
Please review items 3 and 4; under normal operations those expenses, such as sewage fees and trash removal in excess of $500, should be reported on this form.

211 ☐ No pollutants generated
212 ☐ Cost included in rent, taxes, lease agreement, or removal without charge or payment (such as scavenger services)
213 ☐ All costs less than $500
214 ☐ Other — *Specify* —

Item 3 — ANNUAL OPERATING COSTS FOR POLLUTION ABATEMENT

Report the annual operating costs and expenses for pollution abatement activities.

Note: This item should include the operating costs for all pollution abatement equipment and processes in operation regardless of the year the equipment was installed or process initiated. **DO NOT REDUCE** your estimate by **COSTS RECOVERED** (item 5).

Item	TYPE OF POLLUTANT											
	Air (2)			Water (3)			Solid waste					
							Hazardous (4)			Nonhazardous (5)		
(1)	Mil.	Thou.	Dol.	Mil.	Thou.	Dol.	Mil.	Thou.	Dol.	Mil.	Thou.	Dol.
a. Depreciation	301			311			321			331		
b. Labor	302			312			322			332		
c. Materials, supplies, fuel, and electricity	303			313			323			333		
d. Services, equipment leasing, and other costs	304			314			324			334		
e. TOTAL *(Sum of lines a through d)* ⟶	305			315			325			335		

Item 4 — PAYMENTS TO GOVERNMENT FOR POLLUTION REMOVAL

Total payments to governmental (Federal, State, county, local) units for —	Mil.	Thou.	Dol.
a. Public sewage services	401		
b. Municipal solid waste collection/disposal	402		

Item 5 — COSTS RECOVERED THROUGH ABATEMENT ACTIVITIES

Report the best estimate of the value of materials or energy reclaimed (costs recovered) through pollution abatement activities and either reused in production or sold by form of pollution abated.

	Mil.	Thou.	Dol.
a. Air	501		
b. Water	502		
c. Solid waste	503		
d. TOTAL *(Sum of lines 5a through 5c)* ⟶	505		

THE GREEN COPY IS FOR YOUR FILES.

Page 2

		Mil.	Thou.	Dol.
Item 6 — CAPITAL EXPENDITURES FOR ABATEMENT OF AIR POLLUTANTS	**a.** Report total expenditures for new plant and equipment designed to abate air pollutants **through end-of-line techniques.**	601		
	b. Report total expenditures for **changes-in-production process** to abate air pollutants.	602		
	c. TOTAL AIR CAPITAL ***(Sum of lines 6a and 6b)*** →	605		

d. Distribute total expenditures (on line 6c) in terms of percent by TYPE OF POLLUTANTS *(Please give best estimates.)*

EXAMPLE

			Percentage
(1) Particulates 40%	(1) Particulates	611	%
(2) Sulfur oxides 10%	(2) Sulfur oxides	612	%
(3) Nitrogen oxides, etc 35%	(3) Nitrogen oxides and carbon monoxide	613	%
(4) Hydrocarbons-voc 4%	(4) Hydrocarbons-volatile organic compounds	614	%
(5) Lead 3%	(5) Lead	615	%
(6) Hazardous air pollutants ... 1%	(6) Hazardous air pollutants	616	%
(7) Other 7%	(7) Other	617	%
(8) TOTAL 100%	**(8) TOTAL** ***(Sum of lines (1) through (7))***		**100%**

		Mil.	Thou.	Dol.
Item 7 — CAPITAL EXPENDITURES FOR ABATEMENT OF WATER POLLUTANTS	**a.** Report total expenditures for new plant and equipment designed to abate water pollutants **through end-of-line techniques.**	701		
	b. Report total expenditures for **changes-in-production process** to abate water pollutants.	702		
	c. TOTAL WATER CAPITAL ***(Sum of lines 7a and 7b)*** →	705		

		Mil.	Thou.	Dol.
Item 8 — CAPITAL EXPENDITURES FOR SOLID WASTE MANAGEMENT	**a.** Report total expenditures for new plant and equipment designed for management of solid waste. *(See specific instructions.)*	805		

b. Distribute total expenditures (on line 8a) in terms of percent by TYPE OF POLLUTANTS *(Please give best estimates.)*

EXAMPLE

			Percentage
(1) Hazardous 25%	(1) Hazardous	811	%
(2) Nonhazardous 75%	(2) Nonhazardous	812	%
(3) TOTAL 100%	**(3) TOTAL** ***(Sum of lines (1) and (2))***		**100%**

REMARKS
130

Item 9 — CERTIFICATION — This report is substantially accurate and has been prepared in accordance with instructions.

Key	Name of person to contact regarding this report *(Print or type)*	Mo.	Day	Year
131				
132	Telephone — Area code and number — Extension	Signature of authorized person		

FORM MA-200 (9-09-91)

THE GREEN COPY IS FOR YOUR FILES.

MA-200(I)
(10-91)

U.S. DEPARTMENT OF COMMERCE
BUREAU OF THE CENSUS

INSTRUCTIONS AND DEFINITIONS
1991 SURVEY OF POLLUTION ABATEMENT COSTS AND EXPENDITURES

Public reporting burden for this collection of information is estimated to vary from 15 minutes to 8 hours per response (with an average of 1 hour and 15 minutes), including time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding the burden estimate or any other aspect of this collection of information including suggestions for reducing this burden to the Associate Director for Management Services, Paperwork Reduction Project (0607-0176), Room 2027, FB 3, Bureau of the Census, Washington, DC 20233; and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Paperwork Reduction Project (0607-0176), Washington, DC 20503.

GENERAL INSTRUCTIONS

The purpose of the questionnaire is to collect total expenditures made by industry to abate pollutant emissions created by the production process. The survey covers current operating costs and capital expenditures made to reduce pollution in its air, water, or solid forms.

ANSWER ALL QUESTIONS. If you cannot answer a question from your company records, please estimate the answer carefully. In particular cases, identification of abatement expenditures may require the joint efforts of your establishment's financial and engineering staff. If your establishment did not operate for a full year, please indicate the disposition by marking the appropriate box(es) in item 1A, Operational Status.
Report all value figures in thousands of dollars.

Example: 1,125,628 dollars	Mil.	Thou.	Dol.
The **preferred** entry is	1	126	
You **may** report as follows	1	125	628

Report data on a calendar year basis for 1991. However, if your establishment uses a fiscal year that ends between 10/31/91 and 2/28/92, fiscal year data will be acceptable.

For information concerning the possible use of reporting formats other than the form provided, such as computer tape or printouts, contact the Special Surveys Branch on (301) 763-1755.

DEFINITIONS

1. **Pollution abatement** means the reduction or elimination of pollutants created by the production process. Pollution abatement includes prevention, treatment, and recycling. Treatment refers to the wide variety of techniques used to cool, detoxify, decompose, and separate-to-store or ameliorate.

   Efforts to improve environmental aesthetics or employee comfort, such as landscaping or air conditioning, should **not** be included in the answers to this survey. Do **not** include expenditures for health and safety. Do **not** include purchases of motor vehicles with pollution abatement devices. The cost of such devices will be estimated by other means.

   Some establishments manufacture equipment and materials, such as electrostatic precipitators or desulfurized fuels, to be sold to others for pollution abatement purposes. Current operating costs and capital expenditures for the production of such equipment and materials should **not** be reported.

   A. **Air pollutants** are airborne substances, including particulates (dust, fly ash, smoke), sulfur oxides, nitrogen oxides, carbon monoxide, hydrocarbons, volatile organic compounds, lead, hazardous air pollutants (arsenic, asbestos, benzene, beryllium, mercury, radioactive material, and vinyl chloride or those designated by the Clean Air Act and EPA) and other air pollutants.

   B. **Water pollutants** are harmful or objectionable water-borne substances causing alterations in water quality. They include:

   - Conventional pollutants (total suspended solids, oil and grease, BOD5)
   - Nonconventional pollutants (aluminum, ammonia, iron, barium, boron, chlorine, cobalt, fluoride, manganese, phosphorous, sulfur-hydrogen sulfide, titanium, COD)
   - Toxic metals/toxic inorganic compounds (antimony, arsenic, asbestos, beryllium, cadmium, chromium, copper, cyanide, lead, mercury, nickel, silver, thallium, zinc)
   - Toxic organic (benzene, chloroethane, chloromethane, toluene, zylene or those designated by the Clean Water Act and EPA)

2. **Solid waste management** is the collection and disposal of solid waste created by the production process, and changes-in-production processes to reduce the generation of solid waste. Collection and disposal refer to the collection, storage, transport, processing, and disposal of solid waste by incineration, sanitary or other landfill methods, and dumping in authorized areas. Contained liquids are considered solid waste.

   A. **Nonhazardous wastes** includes garbage, trash, sewage sludge, dredged spoils, incinerator residue, wrecked or discarded equipment. Include solid waste produced as a result of air and water pollution abatement.

   B. **Hazardous solid waste** is waste having one of the following four characteristics: ignitability, corrosivity, reactivity, or toxicity. Ignitable waste poses a fire hazard during routine management. Corrosive waste has an extreme pH (strongly acidic or basic) or corrodes steel used in containment. Reactive waste is explosive, readily undergoes violent changes without detonating, or reacts violently or generates toxic gases when mixed with water or moderately strong acids or bases. Toxic waste contains more than allowable concentrations of contaminants such as arsenic, lead, endrin, and toxaphene. For further details see 40 CFR 261, 21-.24 or the Resource Conservation and Recovery Act 1976, Public Law 94-580.42USCS 6921.

3. **Materials and energy recovery** refers to taking materials that cannot be converted into profitmaking output and recycling them for further use. Included are capital expenditures to recycle scrap metal, scrap paper, scrap wood, used oil, used chemicals, etc.; excluded are capital expenditures for secondary products (e.g., animal hides).

SPECIFIC INSTRUCTIONS

Report the status of operations at this plant at the end of 1991.

Item 1A — OPERATIONAL STATUS

Idle Plants — If this plant was temporarily idle during the entire period covered by this survey, this report should still be completed in its entirety.

Sold or Leased Plant — If this plant was sold or leased to another company to operate, indicate the month and year this action took place, and report the new owner or operator in item 1B. If your company owned the plant for more than 6 months, complete the survey form for all items applicable for that period of time, and return the form.

Item 2 — WHO SHOULD REPORT?

No Pollution Abatement Activities — Every concern receiving a report form which had no pollution abatement operating costs, payments to government, or capital expenditures related to the manufacturing process during 1991, should complete only items 2 and 9, and return form for processing. Failure to return the form will require the issuance of followup letters.

Pollution Abatement Activities — Every concern receiving a report form which had some pollution abatement operating costs, payment to government, or capital expenditures during 1991, is required to submit data for items 3 through 8 as applicable.

Items 3 through 5 — ANNUAL COST FOR POLLUTION ABATEMENT — 1991

Item 3 — Report the **annual operating costs and expenses** for pollution abatement incurred in 1991. Include all costs and expenses to operate and maintain plant and equipment that abate air or water pollutants and for solid waste management. **Include** services provided by private contractor for solid waste collection/disposal in item 3d. If the solid waste includes office and cafeteria trash with the industrial, report the entire amount if unable to separate.

The item should include the operating costs for all pollution abatement equipment and processes in operation during 1991 regardless of the year the equipment was installed or the process initiated.

SPECIFIC INSTRUCTIONS — Continued

Items 3 through 5 — ANNUAL COST FOR POLLUTION ABATEMENT — 1991 — Continued

INCLUDE THESE COSTS

- Operation and maintenance of plant and equipment
- Depreciation (or amortization) due to usage of plant and equipment
- Materials, leasing of equipment, parts, and direct labor
- Fuel and power as well as any increased costs due to increased consumption
- Services provided by private contractor

DO NOT INCLUDE THESE COSTS

- Expenditures for research and development
- Expenditures for health and safety
- Interest for financing pollution abatement capital expenditures
- Payment to governmental units (item 4)

Item 4a — Report all **payments to governmental units** for sewage service. Include payments for industrial sewage and payments to government for overstrength effluent charges, sewer district taxed assessment, etc. Include sewage service charges which are included in your local tax bill; estimate if necessary. If the sewage payment includes cafeteria and restroom sewage with the industrial, report the entire amount if unable to separate.

Item 4b — Report all **payments to governmental units** for municipal solid waste collection and disposal services. Included are collection cost to municipal agency (hauler) and disposal cost such as dump or burial fees at a landfill or incinerator.

Item 5 — The estimate of **costs recovered through abatement activities** may have two parts: (1) the value of materials or energy reclaimed through abatement activities that were reused in production, and (2) revenue that was obtained from the sale of materials or energy reclaimed through abatement activities. Heat is an example of reclaimed energy. Value and revenue are net of any additional cost incurred for additional processing of materials or energy to make them reusable or salable.

For air, water, and solid waste, exclude the value of material or energy if it would have been recovered, sold, or reused in production in the absence of pollution control regulations. The value of materials or energy recovered through use of a pollution abatement device installed solely for the purpose of making a manufacturing process profitable should **not** be included.

Capital expenditures for equipment or structures intended for material and energy recovery should be included in the appropriate category in items 6, 7, and 8.

Do **not** reduce annual costs of abatement (item 3) by the estimate reported here.

Items 6 through 8 — CAPITAL EXPENDITURES FOR NEW PLANT AND EQUIPMENT FOR POLLUTION ABATEMENT — 1991

Capital expenditures for new plant and equipment include new plant and equipment acquisitions (both replacement and expansion) and expenditures for construction in progress. Capital expenditures are those chargeable to your establishment's accounts for plant and equipment that are subject to depreciation or to amortization. Total capital expenditures for abatement include expenditures for both end-of-line techniques and changes-in-production processes. Include capital expenditures for equipment or structures intended for material and energy recovery. Exclude expenditures for research and development.

CAPITAL EXPENDITURES FOR ABATEMENT OF AIR POLLUTANTS — 1991

Item 6a — **End-of-line techniques** treat air pollutants after their generation in your production processes by use of separately identifiable abatement (retrofit) facilities such as dust collectors, scrubbers, precipitators, or other treatment processes. These facilities are installed exclusively for the purpose of abating pollutant emissions from your plant or property.

Item 6b — **Changes-in-production processes** reduce or eliminate the generation of pollutants by employing material substitution, improved catalysts, reuse of waste or water, and equipment alteration or replacement. These changes may involve converting equipment to handle the use of substitute fuels that generate less pollutants.

Report only the pollution abatement portion of expenditures for changes-in-production processes. Estimate this portion as the difference between actual expenditures on new plant and equipment and what your establishment would have spent for comparable plant and equipment without air pollution abatement features.

Item 6d — To estimate the impact of emission standards upon capital investment for pollution abatement in industry, it is necessary to match investment expenditures to major types of pollutants abated. **Note:** When a single device has the ability to abate more than one pollutant, the classification of the device is to be guided by the primary purpose for which the device was installed.

CAPITAL EXPENDITURES FOR ABATEMENT OF WATER POLLUTANTS — 1991

Item 7a — Same as item 6a, except that it refers to waste water treatment techniques such as trickling filters, settling ponds, clarifiers, oil spill dikes, and other separately identifiable treatment techniques.

Item 7b — Same as item 6b, except that it refers to abatement of water pollutants. The purpose of pollution abatement may be achieved by converting processes and equipment to enable recycling (closed or partially closed loop systems) or to enable additional uses of water prior to discharge. Do **not** include capital expenditures undertaken exclusively for the purpose of insuring adequate water supply for production.

CAPITAL EXPENDITURES FOR SOLID WASTE MANAGEMENT — 1991

Item 8a — Report all capital expenditures made for solid waste management. Include all capital expenditures made for the collection and disposal of solid waste, materials and energy recovery, and changes-in-production processes to reduce the generation of solid waste.

Item 8b — To estimate the impact of standards upon capital investment for pollution abatement in industry, it is necessary to match investment expenditures to the types of pollutants abated.

IF YOU HAVE ANY QUESTIONS OR SUGGESTIONS REGARDING THIS REPORT, PLEASE CALL (301) 763-1755.

Return completed form within 90 days to:

Bureau of the Census
1201 East 10th Street
Jeffersonville, IN 47132-0001

Appendix B. Pollution Abatement Form and Instructions (Form PA-1)

OMBNo. 0607-0176: Approval Expires 11/30/92

IMPORTANT: *This report is due April 22, 1992*

FORM **PA-1**
(11-27-91)

The collection of this information is required by law (Title 13 U.S.C.). Your response is accorded confidential treatment and can be used only for statistical purposes (Title 13, Sec. 9 U.S.C.). It cannot be used for purposes of taxation, investigation, or regulation. Your cooperation is needed to make the results comprehensive, accurate, and timely.

U.S. DEPARTMENT OF COMMERCE
BUREAU OF THE CENSUS

STRUCTURES AND EQUIPMENT EXPENDITURES SURVEY: SUPPLEMENT FOR POLLUTION ABATEMENT

1991

Return To: **U.S. Department of Commerce**
Bureau of the Census
Industry Division, Room 2105, FB-4
Washington, DC 20233-0001

(Please correct any error in name, address, and ZIP Code)

ASSISTANCE: Telephone (301) 763-1755

Name and title of person to contact regarding this report.	Telephone number – Area code	Number	Extension	Date

The information you provide in this report is used to assess pollution control programs and their effect on overall capital expenditures and the near-term economic situation. Questions concerning this report may be directed to the address or telephone number shown above.

Public reporting burden for this collection of information is estimated to vary from 30 to 90 minutes per response with an average of 60 minutes per response, including time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding the burden estimate or any other aspect of this collection of information including suggestions for reducing this burden to the Associate Director for Management Services, Paperwork Reduction Project 0607-0176, Room 2027, Bureau of the Census, Washington, DC 20233-0001; and to the Office of Management and Budget, Paperwork Reduction Project 0607-0176, Washington, DC 20503.

GENERAL INSTRUCTIONS AND DEFINITIONS

This questionnaire collects information on capital expenditures made by industry to abate pollutant emissions. The survey covers capital expenditures made to reduce pollution in its air, water, or solid forms. Results from this survey appear annually in the Survey of Current Business and are valuable in public and private decision making.

Report data on a calendar year basis. If your enterprise uses a fiscal year that ends near the end of the calendar year (between October 31 and February 28), fiscal year data will be acceptable. If your fiscal year ends near midyear, averaging adjacent fiscal year data will be acceptable.

If data requested are not available directly from your records, carefully prepared estimates are acceptable. In particular cases, identification of abatement expenditures may require the joint efforts of your enterprise's financial and engineering staffs.

If you have not made or do not expect to make capital expenditures for pollution abatement, just answer items 1 and 2 and return the form. Otherwise, please complete the entire form. If you're completing the entire form but have no expenditures for a particular item, please enter a zero, rather than leaving the item blank, using dashes, or putting N.A. (for not applicable).

Pollution abatement means the reduction or elimination of pollutants emitted from your property or activities. Pollution abatement includes prevention, treatment, and recycling. Treatment refers to the wide variety of techniques used to cool, detoxify, decompose, and separate-to-store or ameliorate. For further information on pollution abatement see the reverse side of this form.

Domestic new capital expenditures include expenditures for new structures and equipment, whether for replacement or expansion. Capital expenditures are costs which are generally chargeable to fixed asset accounts and for which depreciation or amortization accounts are ordinarily maintained. Report expenditures by your enterprise and its majority-owned domestic subsidiaries for structures and equipment utilized in the United States, whether purchased in the United States or abroad. Domestic refers to the 50 States and the District of Columbia.

Include expenditures for facilities under construction, but not yet in operation, and the cost of construction work performed by your employees (force-account construction work).

Exclude expenditures for land (except for land development and improvements), residential structures (except for the estimated value of the portion devoted to commercial or business use), noncapitalized maintenance and repairs, depletable assets, and mineral rights (except for capitalized exploration and development costs of mineral properties). Exclude the value of structures built, and other work performed, by your enterprise on contract to others.

An enterprise that acquires domestic new structures and equipment and then leases them to others should report expenditures for those assets. An enterprise which uses leased assets should only report the cost of capitalized improvements that it makes to those assets.

For information on reporting "sale and leaseback" arrangements and for other details on domestic new capital expenditures, see Definition of Terms on your **PE-4 Fourth Quarter Report.**

ITEM 1 — DOMESTIC NEW CAPITAL EXPENDITURES

Item	Actual 1991 (Bil. Mil. Thou. Dol.)	Expected 1992 (Bil. Mil. Thou. Dol.)
Report your **ANNUAL** expenditures for new structures and equipment (including those for pollution abatement) as reported on your PE-4 Fourth Quarter Report.	$, , ,000	$, , ,000

ITEM 2 — POLLUTION ABATEMENT DOMESTIC NEW CAPITAL EXPENDITURES

a. Except for emission abatement devices on cars and trucks, did your company have or does it expect to have expenditures for domestic new structures and equipment to manage solid waste or to abate air or water pollutant emissions from your property or activities?

1. Actual 1990 ☐ Yes ☐ No ☐ Minimal ($500. or less)
2. Expected 1991 ☐ Yes ☐ No ☐ Minimal ($500. or less)

If "yes" to actual or expected, estimate expenditures for the relevant year(s) in item 2b and complete items 3 through 5. If no expenditures reported, indicate the reason why in part 2c. If minimal for both years, sign and return form.

	Actual 1991 (Bil. Mil. Thou. Dol.)	Expected 1992 (Bil. Mil. Thou. Dol.)
b. Report your **ANNUAL** expenditures for new structures and equipment for **POLLUTION ABATEMENT**. These expenditures should equal the sum of lines 3c, 4c, and 5c from the reverse side of the form.	$, , ,000	$, , ,000

c. If no expenditures reported, mark (X) in the appropriate box, sign, and return the form to the address above.

1. ☐ No pollutants generated.
2. ☐ We buy services or use leased capital for pollution abatement or solid waste management.
3. ☐ Previously purchased capital meets our current needs.
4. ☐ Other reason — *Please specify* ____________

(CONTINUE ON THE REVERSE SIDE)

DEFINITIONS FOR ITEMS 3 THROUGH 5

Pollution abatement means the reduction or elimination of pollutants emitted from your property or activities. Pollution abatement includes prevention, treatment, and recycling. Treatment refers to the wide variety of techniques used to cool, detoxify, decompose, and separate-to-store or ameliorate.

Efforts to improve environmental aesthetics or employee comfort, such as landscaping or air conditioning, should not be included in the answers to this survey. Do not include costs of emission abatement devices on motor vehicles. The cost of such devices will be estimated by other means.

Some enterprises manufacture equipment, such as electrostatic precipitators, to be sold to others for pollution abatement purposes. Capital expenditures for the production of such equipment should not be reported.

Air pollutants are airborne substances including particulates (dust, fly ash, smoke), sulfur oxides, nitrogen oxides, carbon monoxide, hydrocarbons, odors, fluorides, lead and other heavy metals, radioactive and toxic substances.

Water pollutants are waterborne substances including phosphates, nitrates (-trites), substances that generate chemical or biochemical oxygen demand, solids, acids, bases, heavy metals, radioactive and toxic substances, synthetic organic molecules, harmful microbes, oil, grease, dyes, and heat.

Solid waste includes garbage, trash, sewage sludge, dredged spoil, incinerator residue, wrecked or discarded equipment, biological or chemical wastes, radioactive and other toxic materials. Include solid waste produced as a result of air and water pollution abatement.

ITEM 3a — End-of-line techniques treat air pollutants after their generation in your production processes by use of separately identifiable abatement facilities such as dust collectors, scrubbers, precipitators, or other treatment processes useful for retrofitting. These facilities are installed exclusively for the purpose of abating pollutant emissions from your plant or property.

ITEM 3b — Changes-in-production processes reduce or eliminate the generation of pollutants by employing material substitution, improved catalysts, reuse of waste or water, and equipment alteration. These changes may involve converting equipment to handle the use of substitute fuels that generate less pollutants.

ITEM 4a — Same as Item 3a, except that it refers to wastewater treatment techniques such as trickling filters, settling ponds, clarifiers, oil spill dikes, and other separately identifiable treatment techniques.

ITEM 4b — Same as Item 3b, except that it refers to abatement of water pollutants. The purpose of pollution abatement may be achieved by converting processes and equipment to enable recycling (closed or partially closed loop systems) or to enable additional uses of water prior to discharge. Do not include capital expenditures undertaken exclusively for the purpose of insuring adequate water supply for production.

ITEM 5 — Solid waste, management is the collection and disposal of solid waste, materials and energy recovery, and changes-in-production processes to reduce the generation of solid waste. Collection and disposal refers to the collection, storage, transport, processing, and disposal of solid waste by incineration, sanitary or other landfill methods, and dumping in authorized areas. Materials and energy recovery refers to taking materials that cannot be converted into profitmaking output and recycling them for further use. Included are capital expenditures to recycle scrap metal, scrap paper, scrap wood, etc.; excluded are capital expenditures for secondary products. (e.g., animal hides).

ITEM 5a — Hazardous solid waste is waste either explicitly regulated under the Resource Conservation and Recovery Act or having one of the following four characteristics: ignitability, corrosivity, reactivity, or toxicity. Ignitable waste poses a fire hazard during routine management. Corrosive waste has an extreme pH (strongly acidic or basic) or corrodes steel used in containment. Reactive waste is explosive, readily undergoes violent changes without detonating, or reacts violently or generates toxic gases when mixed with water or moderately strong acids or bases. Toxic waste contains more than allowable concentrations of contaminants such as arsenic, lead, endrin, and toxaphene. (For further details see 40 CFR 261.21-.24.)

ITEM 3 — AIR POLLUTION ABATEMENT DOMESTIC NEW CAPITAL EXPENDITURES

Item	Actual 1991 (Bil. Mil. Thou. Dol.)	Expected 1992 (Bil. Mil. Thou. Dol.)
a. Report your expenditures for new structures and equipment designed to abate air pollutants through end-of-line techniques.	$, , ,000	$, , ,000
b. In addition or as an alternative to end-of-line techniques, did this enterprise make expenditures to acquire or modify structures and equipment for changes-in-production processes to abate air pollutants?	☐ Yes ☐ No — *Go to c*	☐ Yes ☐ No — *Go to c*
If "yes," report the difference between these expenditures for new structures and equipment and the expenditures that you would have made for comparable structures and equipment without air pollution abatement features.	$, , ,000	$, , ,000
c. Total air capital *(Sum of lines 3a and 3b)*	$, , ,000	$, , ,000

ITEM 4 — WATER POLLUTION ABATEMENT DOMESTIC NEW CAPITAL EXPENDITURES

Item	Actual 1991	Expected 1992
a. Report your expenditures for new structures and equipment designed to abate water pollutants through end-of-line techniques.	$, , ,000	$, , ,000
b. In addition or as an alternative to end-of-line techniques, did this enterprise make expenditures to acquire or modify structures and equipment for changes-in-production processes to abate water pollutants?	☐ Yes ☐ No — *Go to c*	☐ Yes ☐ No — *Go to c*
If "yes," report the difference between these expenditures for new structures and equipment and the expenditures that you would have made for comparable structures and equipment without water pollution abatement features.	$, , ,000	$, , ,000
c. Total water capital *(Sum of lines 4a and 4b)*	$, , ,000	$, , ,000

ITEM 5 — SOLID WASTE MANAGEMENT DOMESTIC NEW CAPITAL EXPENDITURES

Item	Actual 1991	Expected 1992
Report your expenditures on new structures and equipment designed for management of: **a.** Hazardous solid waste	$, , ,000	$, , ,000
b. Nonhazardous solid waste	$, , ,000	$, , ,000
c. Total solid waste management capital *(Sum of lines 5a and 5b)*	$, , ,000	$, , ,000

REMARKS — Suggestions for improvements in this questionnaire are solicited.

FORM PA-1 (11-27-91)

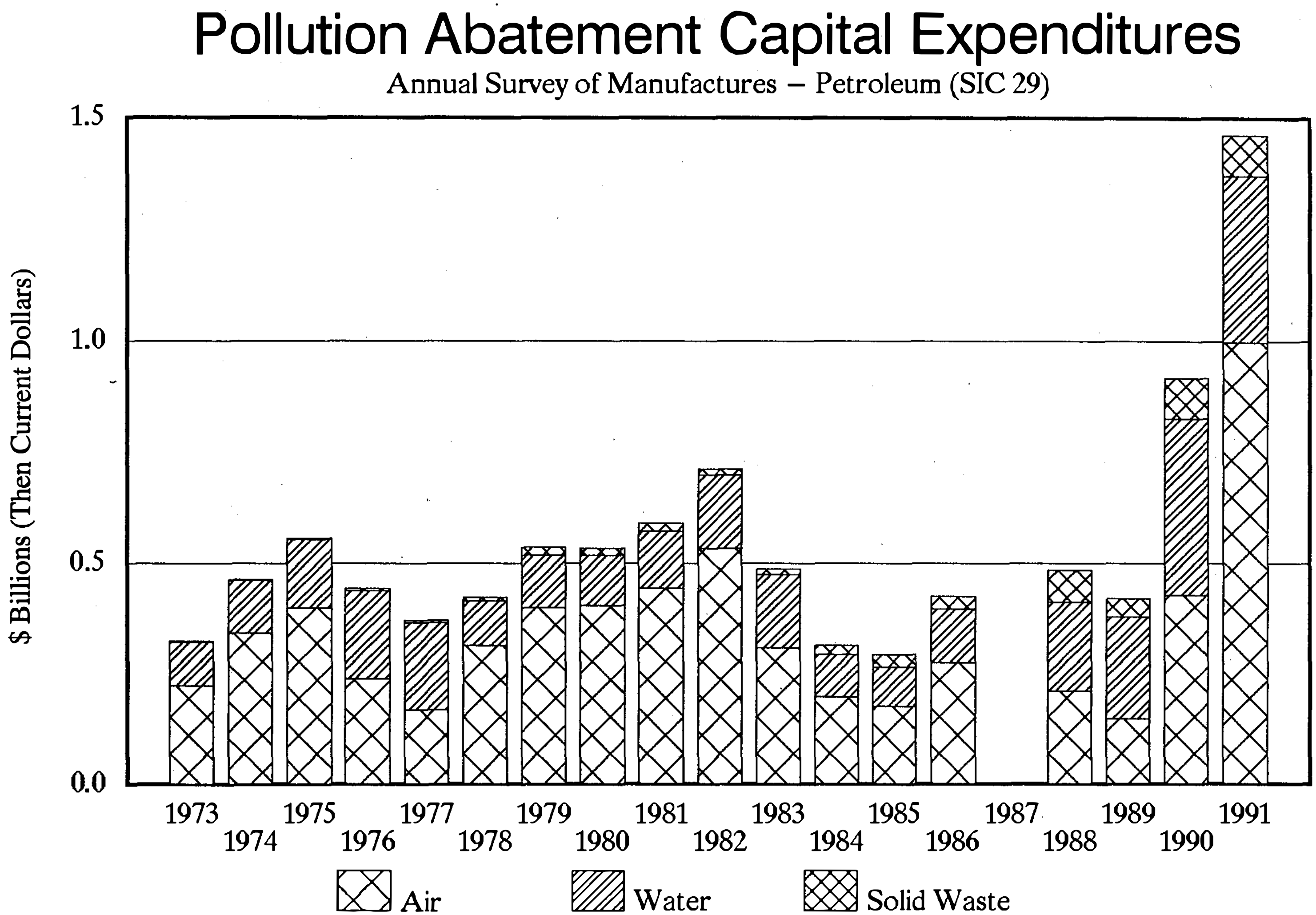
TABLE APP. J.II-4

Comparison of Environmental Expenditures from API and Department of Commerce Data

	......API Environmental Expenditures - Manufacturing...... ($ MILLIONS)										....Dept. of Commerce.... MA-200 report Petroleum (SIC 29) Pollution Abatement		....NPC Survey....	
			Capital Expenditures ......Survey responses......					Administrative, Operating & Maintenance Expenses					
	Total U.S. Industry	Refining Response	Total	Air	Water	Solid Waste	Other	Survey	Total US	Capital Expend.	Gross Annual Costs (GAC)	Capital Expend.	O&M and Pne Time Expense
1966	100.0	80%	80.0	62.0	18.0	0.0	0.0	61.0	76.3				
1967	162.5	80%	130.0	90.0	40.0	0.0	0.0	70.0	87.5				
1968	186.3	80%	149.0	100.0	49.0	0.0	0.0	77.0	96.3				
1969	232.5	80%	186.0	130.0	56.0	0.0	0.0	91.0	113.8				
1970	237.5	80%	190.0	115.0	70.0	5.0	0.0	147.0	183.8				
1971	585.0	80%	468.0	329.0	112.0	27.0	0.0	204.0	255.0				
1972	446.3	80%	357.0	264.0	86.0	7.0	0.0	280.0	350.0				
1973	587.5	80%	470.0	369.0	93.0	8.0	0.0	333.0	416.3	321.8	337.8		
1974	640.0	80%	512.0	373.0	123.0	16.0	0.0	430.0	537.5	462.3	420.1		
1975	743.1	80%	593.0	450.0	130.0	13.0	0.0	479.0	600.3	555.7	563.1		
1976	745.0	80%	596.0	385.0	203.0	8.0	0.0	820.0	1,025.0	441.4	774.8		
1977	550.0	80%	440.0	230.0	189.0	21.0	0.0	1,068.0	1,335.0	369.2	960.3		
1978	528.8	80%	423.0	332.0	83.0	8.0	0.0	1,145.0	1,431.3	420.1	1,010.4		
1979	802.9	70%	562.0	448.0	100.0	14.0	0.0	1,327.0	1,895.7	534.3	1,173.8		
1980	923.9	71%	656.0	498.0	123.0	35.0	0.0	1,824.0	2,569.0	531.9	1,418.0		
1981	703.7	81%	570.0	403.0	146.0	21.0	0.0	1,952.0	2,409.9	590.6	1,685.5		
1982	1,023.5	81%	829.0	631.0	170.0	28.0	0.0	1,984.0	2,449.4	712.1	1,800.8		
1983	700.0	77%	539.0	386.0	129.0	24.0	0.0	1,907.0	2,476.6	485.0	1,893.7		
1984	439.0	82%	360.0	235.0	101.0	24.0	0.0	1,907.0	2,325.6	311.7	2,083.5		
1985										290.4	2,063.4		
1986										424.3	2,005.2	888.0	1,895.0
1987												1,305.0	1,405.0
1988										482.8	2,005.5	1,364.0	1,951.0
1989										417.6	2,170.0	787.0	2,254.0
1990	1,286.0	100%	1,286.0	601.0	569.0	100.0	16.0	2,424.0	2,424.0	916.8	2,704.9	1,216.0	2,677.0
1991	1,809.0	100%	1,809.0	1,240.0	467.0	65.0	37.0	2,309.0	2,309.0	1,462.5	2,849.0		
Totals	13,432.3		11,205.0	7,671.0	3,057.0	424.0	53.0	20,839.0	25,367.0	9,730.5	27,919.8		
Averages	639.6	81.0%	533.6	365.3	145.6	20.2	2.5	992.3	1,208.0	540.6	1,551.1		
Count	21	21	21	21	21	21	21	21	21	18	18		

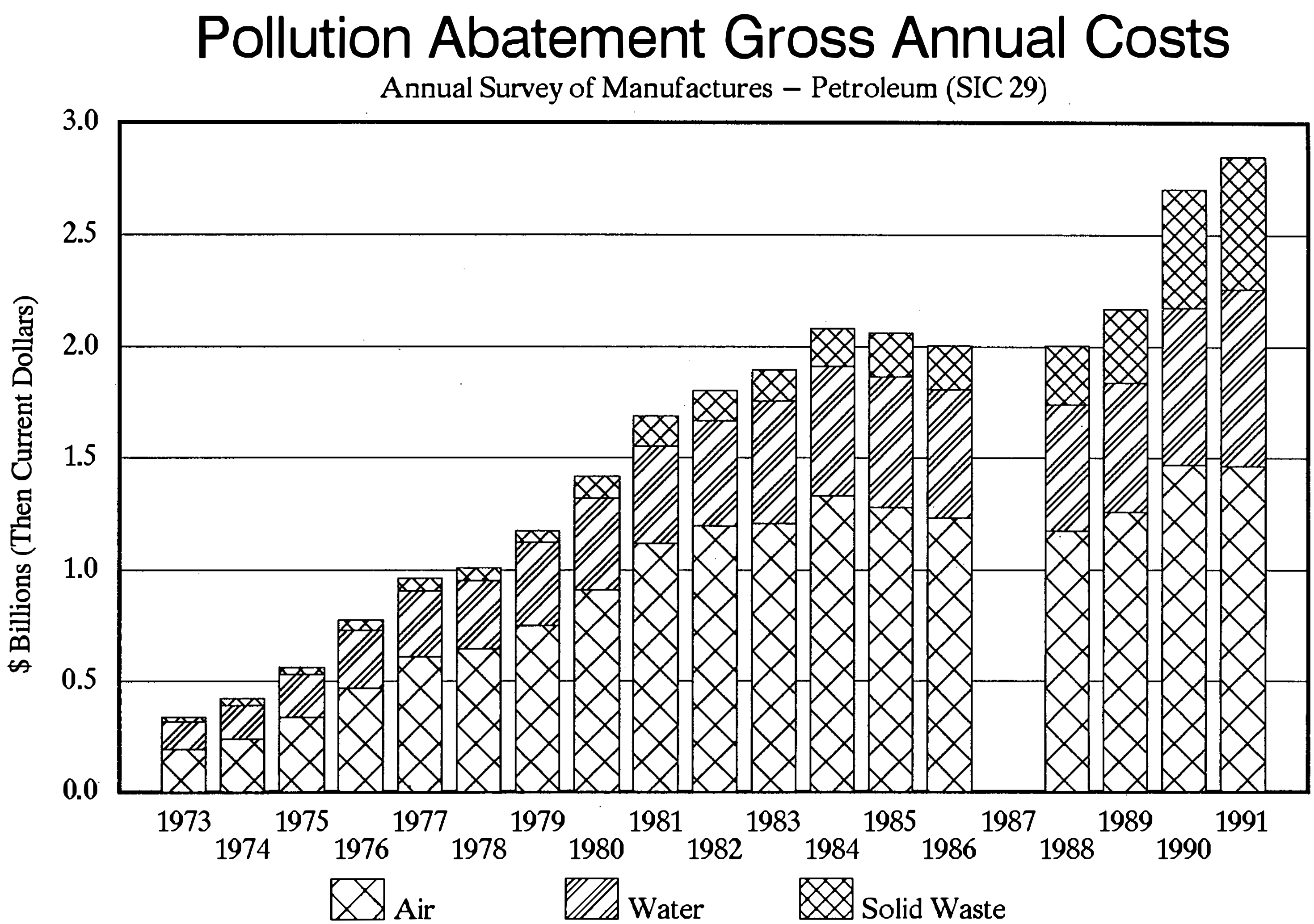
Source: Environmental Expenditures of the
United States Petroleum Industry,1975-1984
and other draft reports.
American Petroleum Institute
Washington,D.C.

FIGURE J.II-5



Source: U.S. Department of Commerce report MA 200–1.
No survey was taken for 1987.

FIGURE J.II-6



Source: U.S. Department of Commerce MA200–1
No survey was taken for 1987.

Table APP.J.II-5

POLLUTION ABATEMENT CAPITAL EXPENDITURES AND OPERATING COSTS BY FORM OF ABATEMENT
ALL INDUSTRIES (SIC 2)
$ MILLIONS (THEN CURRENT DOLLARS)

	Annual Survey of Manufactures (ASM)		Pollution Abatement Capital Expenditures (PACE)				Pollution Abatement Gross Annual Costs (GAC) including payments to Governmental Units				Standard Error of Change		Standard Error of Estimate (percent)	
Year	Total Value of Shipments	Total New Capital Expenditures	Total	Air	Water	Solid Waste	Total	Air	Water	Solid Waste	PACE	GAC	PACE	GAC
1991	2,826,207.3	98,816.4	7,390.1	3,706.3	2,814.6	869.2	17,386.8	5,033.5	6,345.0	6,008.3	4	2	4	2
1990	2,873,501.6	101,953.1	6,030.8	2,562.0	2,651.4	817.5	17,070.7	5,010.9	6,416.4	5,643.4	4	2	2	2
1989	2,793,014.5	97,186.7	4,309.0	1,819.0	1,824.5	665.5	15,625.6	4,694.2	5,853.4	5,078.0	6	2	3	2
1988	2,682,605.9	80,571.7	3,423.3	1,524.1	1,289.4	609.7	14,008.2	4,466.5	5,275.9	4,265.8				2
1987	2,475,901.0	78,647.8												
1986	2,260,314.6	76,354.5	2,846.9	1,462.9	1,038.7	345.3	12,258.1	4,261.0	4,820.2	3,176.9			1	2
1985	2,280,183.8	83,058.3	2,809.7	1,292.3	1,017.9	499.5	11,667.9	4,330.2	4,609.5	2,738.3			1	1
1984	2,253,847.2	75,185.8	2,171.8	1,037.8	887.8	246.9	10,888.1	4,189.3	4,296.4	2,402.5			2	1
1983	2,054,853.3	61,930.5	2,045.0	1,029.0	819.0	197.1	9,925.1	3,806.9	3,943.2	2,175.0			3	1
1982	1,960,205.8	74,561.6	3,024.1	1,828.2	977.4	218.5	8,565.0	3,455.9	3,488.5	1,619.9			3	1
1981	2,017,542.5	78,632.3	3,484.9	2,193.6	1,028.4	263.1	9,109.9	3,697.8	3,554.3	1,855.7	-1	12	1	1
1980	1,850,927.0	70,568.8	3,502.9	2,105.5	1,146.5	251.0	8,141.8	3,297.8	3,193.1	1,650.6	-2	10	3	1
1979	1,727,214.6	61,533.0	3,564.5	2,071.9	1,245.7	246.9	7,399.9	3,061.8	3,015.6	1,322.5	9	8	1	1
1978	1,523,429.9	55,243.9	3,315.9	1,871.5	1,262.9	181.2	6,327.5	2,546.6	2,550.4	1,230.3	-6	16	1	2
1977	1,358,526.4	47,459.0	3,522.6	1,667.9	1,695.1	159.9	5,470.2	2,259.3	2,221.6	989.7	0	21	1	1
1976	1,185,695.3	40,669.9	3,531.7	1,797.8	1,599.2	134.8	4,539.2	1,888.2	1,824.0	827.1	-3	24	2	1
1975	1,039,377.4	37,262.1	3,637.6	2,235.7	1,280.1	121.8	3,673.1	1,508.1	1,496.6	669.7	17	18	1	1
1974	1,017,846.9	35,698.7	3,101.1	1,947.5	1,008.8	144.7	3,102.8	1,210.7	1,261.4	630.7	32	27	1	1
1973	875,443.2	26,972.9	2,353.7	1,417.5	827.8	108.2	2,445.2	960.5	993.3	491.7			2	1

SOURCE: U.S. Department of Commerce
Economics and Statistics Administration
BUREAU OF THE CENSUS
CURRENT INDUSTRIAL REPORTS
Pollution Abatement
Costs and Expenditures
MA200-1, 1980-1991

Table APP.J.II-6

POLLUTION ABATEMENT CAPITAL EXPENDITURES AND OPERATING COSTS BY FORM OF ABATEMENT
PETROLEUM AND COAL PRODUCTS (SIC 29)
$ MILLIONS (THEN CURRENT DOLLARS)

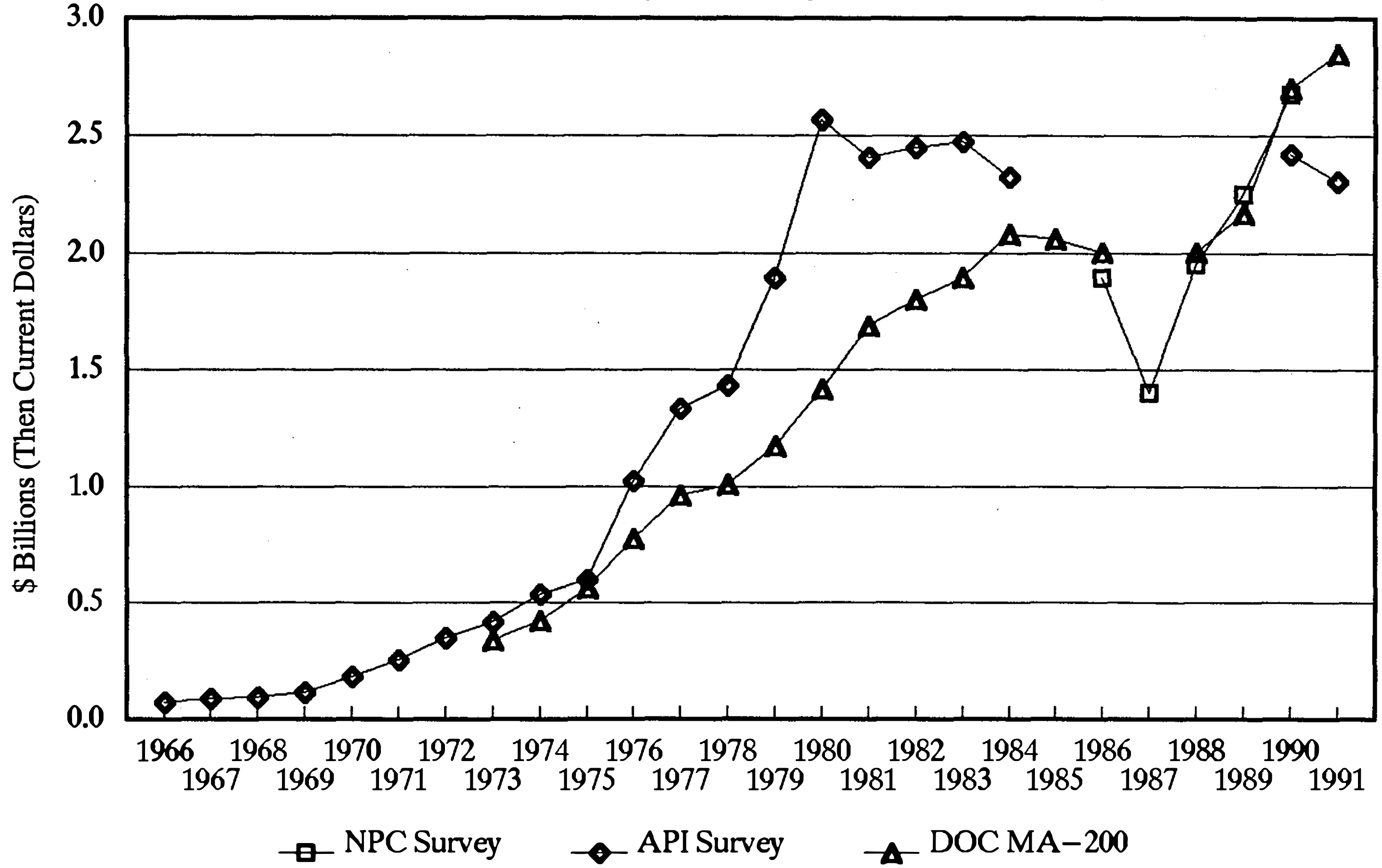
	Annual Survey of Manufactures (ASM)		Pollution Abatement Capital Expenditures (PACE)				Pollution Abatement Gross Annual Costs (GAC) including payments to Governmental Units				Standard Error of Change		Standard Error of Estimate (percent)	
Year	Total Value of Shipments	Total New Capital Expenditures	Total	Air	Water	Solid Waste	Total	Air	Water	Solid Waste	PACE	GAC	PACE	GAC
1991	158,076.4	5,895.9	1,462.5	996.7	373.3	92.5	2,849.0	1,464.7	793.9	590.4	3	2	2	3
1990	172,588.6	4,158.1	916.8	425.7	400.8	90.3	2,704.9	1,472.2	701.9	530.8	7	4	3	4
1989	143,702.1	3,331.2	417.6	146.5	230.4	40.7	2,170.0	1,258.2	578.7	333.0	3	2	3	2
1988	131,414.8	2,614.1	482.8	208.3	203.7	70.8	2,005.5	1,175.8	561.7	268.0			2	2
1987														
1986	124,878.3	2,577.5	424.3	273.6	121.5	29.2	2,005.2	1,230.9	578.0	196.4			1	1
1985	179,134.9	3,438.0	290.4	175.0	88.4	27.0	2,063.4	1,278.5	586.5	198.5			1	1
1984	189,010.9	3,774.6	311.7	195.1	96.8	19.8	2,083.5	1,327.9	583.8	171.1			1	1
1983	192,570.3	4,583.0	485.0	308.2	164.7	12.0	1,893.7	1,203.6	552.3	137.9			3	3
1982	208,918.6	6,578.9	712.1	533.2	165.7	13.1	1,800.8	1,195.1	472.0	133.7			3	1
1981	224,131.4	5,157.9	590.6	440.8	131.7	18.2	1,685.5	1,118.0	437.2	130.2	11	19	1	1
1980	198,673.1	3,614.5	531.9	402.3	114.2	15.4	1,418.0	910.1	406.9	101.0	-1	21	3	1
1979	148,366.6	3,272.9	534.3	397.8	119.4	17.1	1,173.8	750.7	370.8	52.3	27	18	8	7
1978	103,871.1	2,286.1	420.1	311.8	100.7	7.6	1,010.4	644.7	308.1	57.7	14	5	2	1
1977	97,452.7	2,261.3	369.2	168.0	196.0	5.3	960.3	609.1	293.1	58.1	-16	24	1	1
1976	82,347.0	2,836.8	441.4	236.5	199.8	5.2	774.8	466.1	263.3	45.3	-21	38	1	1
1975	69,484.6	2,417.8	555.7	398.2	155.7	1.7	563.1	339.4	192.1	31.7	20	34	1	1
1974	58,875.8	1,845.1	462.3	341.3	119.7	1.3	420.1	238.3	153.3	28.5	44	24	1	5
1973	34,899.0	1,107.0	321.8	222.5	96.1	3.2	337.8	192.5	125.4	19.9			3	5

SOURCE: U.S. Department of Commerce
Economics and Statistics Administration
BUREAU OF THE CENSUS
CURRENT INDUSTRIAL REPORTS
Pollution Abatement
Costs and Expenditures
MA200-1, 1980-1991

FIGURE J.II-7

Environmental Expenses for U.S. Refining Industry

API and NPC Surveys versus Dept. of Commerce Survey

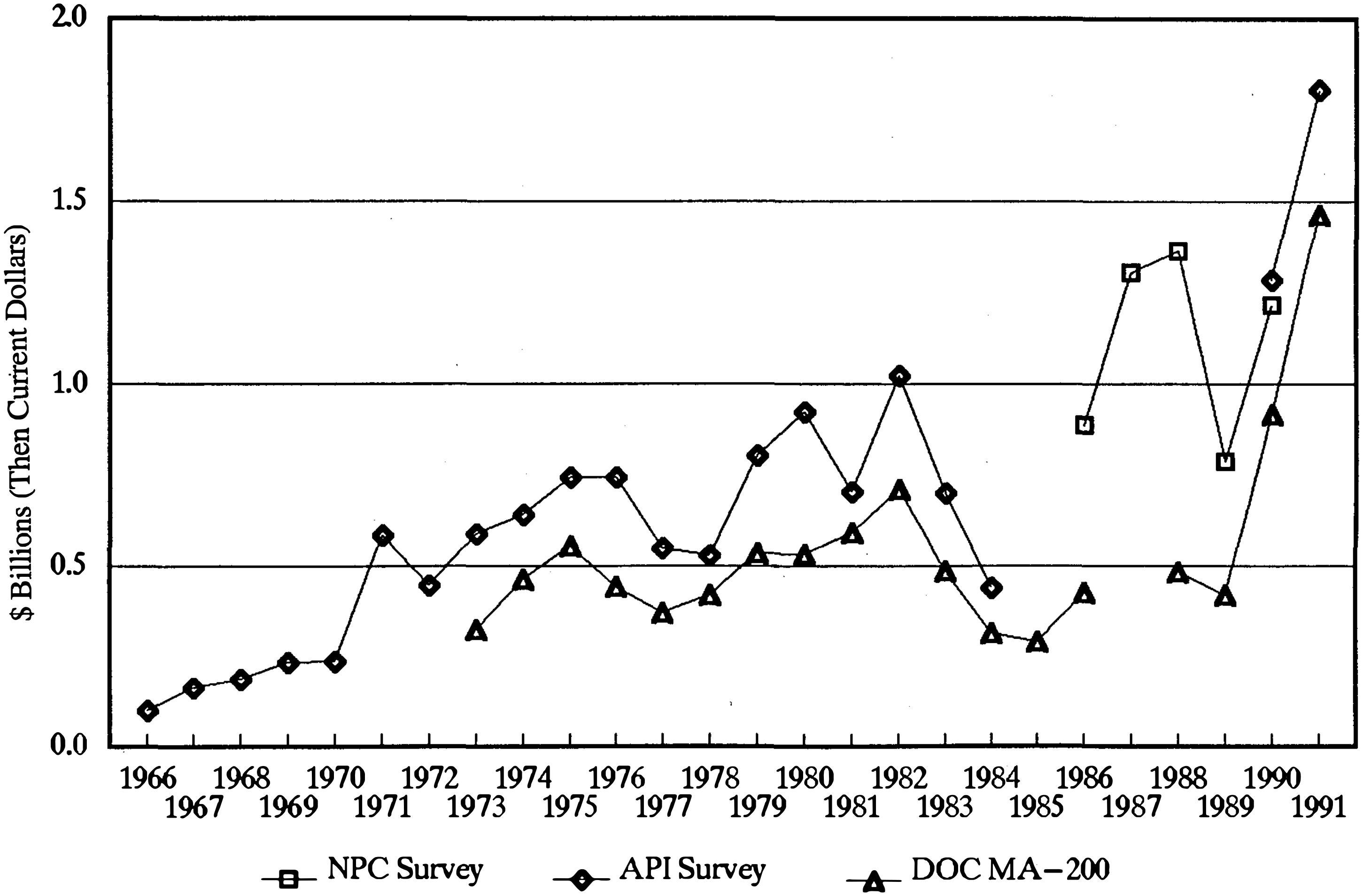


Sources: API survey results extrapolated to total U.S. refining capacity. NPC survey (1986–1990). Department of Commerce report MA–200 Annual Survey of Manufactures – Petroleum (SIC 29).

FIGURE J.II-8

Environmental Capital Expenditures for U.S. Refining Industry

API and NPC Surveys versus Dept. of Commerce Survey

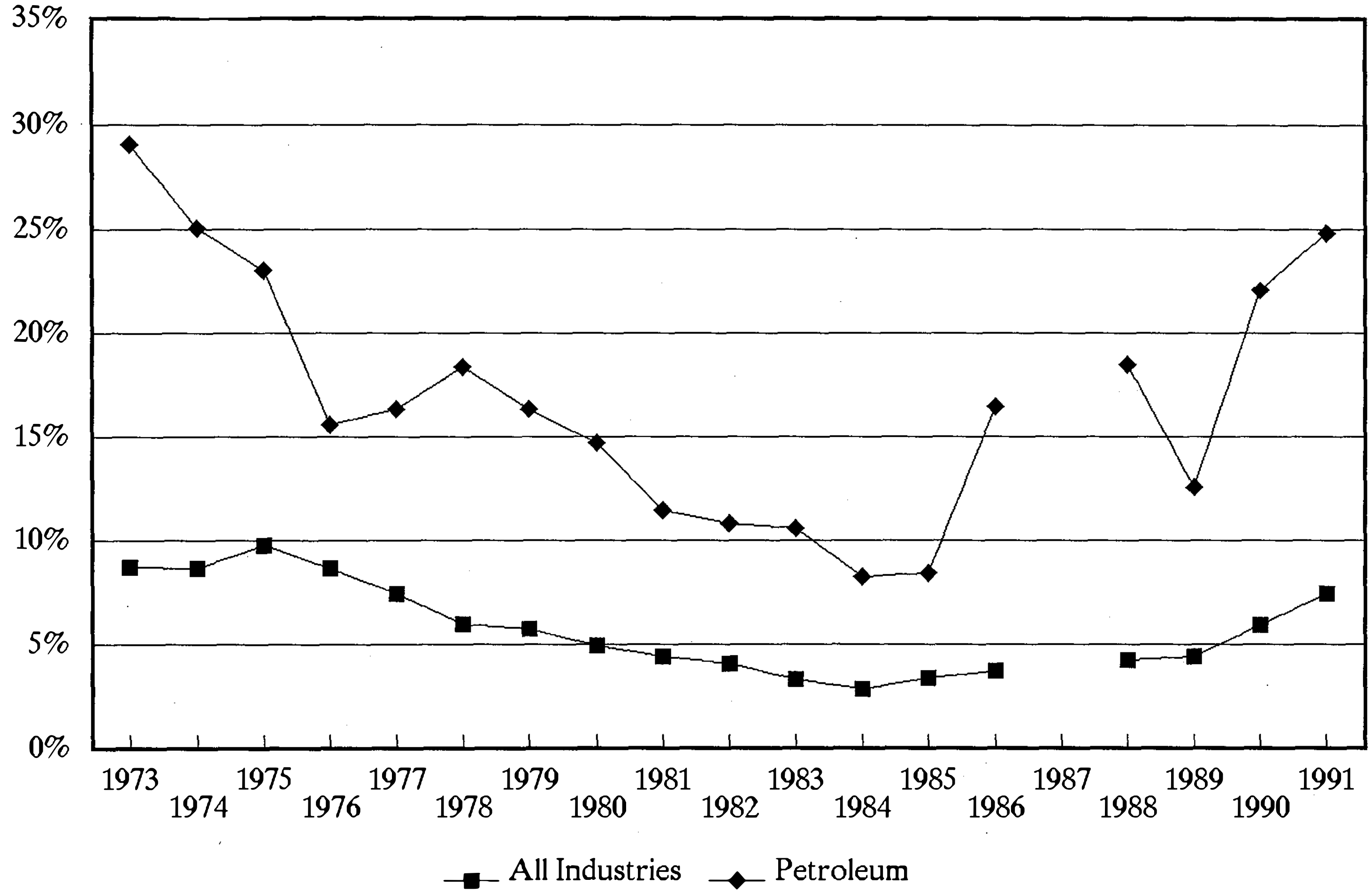


Sources: API survey results extrapolated to total U.S. refining capacity. NPC survey (1986–1990). Department of Commerce report MA–200 Annual Survey of Manufactures – Petroleum (SIC 29).

FIGURE J.II-9

Pollution Abatement as Percent of Total Capital Expenditures

All Industries (SIC 2) and Petroleum (SIC 29)

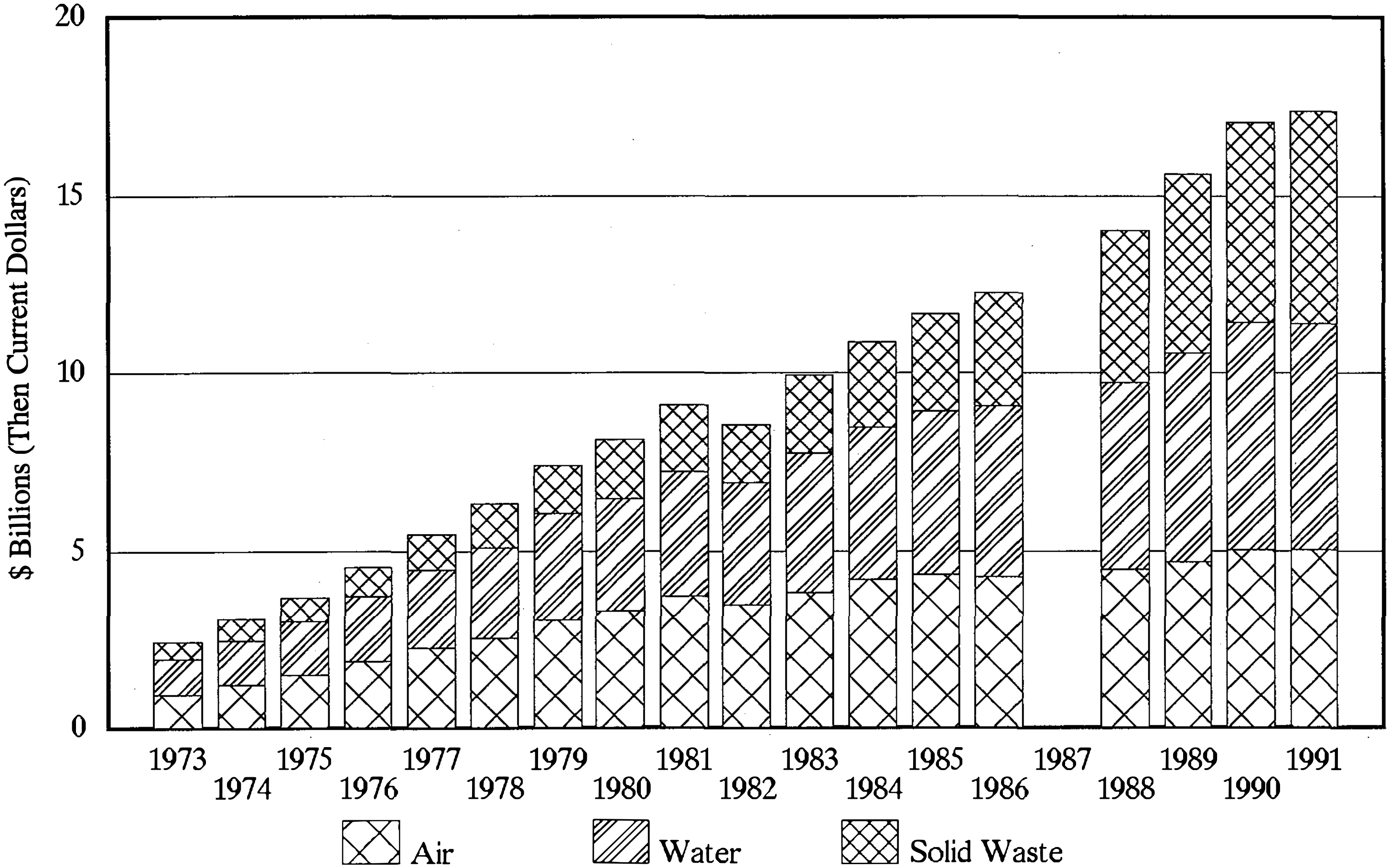


Source: U.S. Bureau of Census, Pollution Abatement Costs and Expenditures, MA200-1.
No survey was taken for 1987.

FIGURE J.II-10

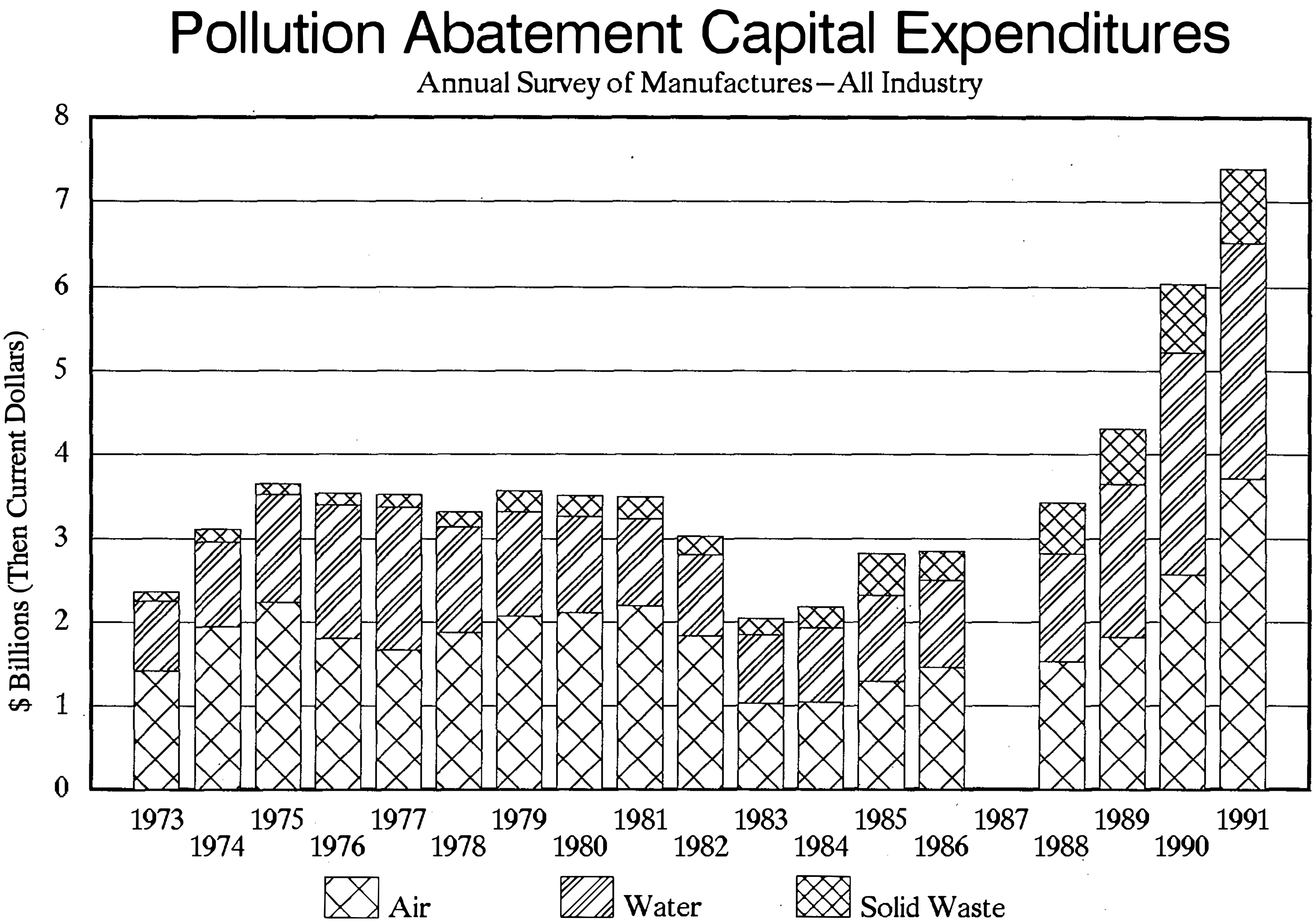
Pollution Abatement Gross Annual Costs

Annual Survey of Manufactures' – All Industries



Source: U.S. Bureau of the Census,Pollution Abatement Costs and Expenditures, MA200–1 Table 1.
No survey was taken for 1987.

FIGURE J.II-11.



Source: U.S. Bureau of the Census, Pollution Abatement Costs and Expenditures, MA200–1.
No survey was taken for 1987.

SECTION III

INDUSTRY FINANCIAL BACKGROUND

Structure of the Financial Reporting System
Form EIA-28

Reporting Format

The FRS data system is designed to permit review of the functional performance of major energy-producing companies in total, as well as by specific functions and geographic areas of operation. The financial reporting schedules obtain data on revenues, cost, and profits, thereby indicating financial flows and performance characteristics. In addition, Form EIA-28 collects balance sheet data (i.e., accumulated property, plant, and equipment, etc.), along with data on new investment in these accounts. To complement the financial data, a series of statistical schedules are included to trace physical activity patterns and to evaluate several physical/financial relationships.

In greater detail, the structure of the reporting package is as follows:

1. Financial Reporting

   a. The starting point is the three basic financial statements required by the Securities and Exchange Commission (SEC) Form 10-K:

      i. Consolidating Statement of Income (Schedule 5110)
      ii. Selected Consolidating Financial Data (Balance Sheets) (Schedule 5120)
      iii. Consolidated Statement of Cash Flows (Schedule 5131)

   b. Corporate-wide financial information is first disaggregated by functional lines (segments) on Schedule 5110 and 5120 as follows:

      i. Petroleum
      ii. Coal
      iii. Other Energy (includes Nuclear)
      iv. Nonenergy (includes Chemicals)

   c. Nonenergy data is collected to describe corporate resource investment strategy and to allow aggregation of the FRS detailed schedules into the consolidated company amounts.

2. Operating and Statistical Information

   a. For each type of energy activity, complementary operating information is obtained through the following schedules:

      i. Petroleum (5211-5246)
      ii. Coal (5341)

b. The schedules are designed to correspond to the financial information so that level of effort in the financial sense can be compared to physical results.

3. Complementary Schedules

   a. Examine corporate research and development funding priorities (Schedule 5111)

   b. Reveal impact of tax policy on financial results of reporting companies (Schedule 5112)

   c. Monitor raw material acquisition and refined product disposition strategies of FRS companies (5211-5212)

   d. Trace changes in reserves for petroleum (including natural gas) (5246) and coal (5341).

Petroleum Segment Overview

The petroleum line of business is further disaggregated into segments. These segments are presented as though each were a separate entity, with certain limitations, entering into transactions with other segments and third parties.

The following lists each segment within the petroleum line of business along with a brief description of that segment's principal revenue-generating product or service.

1. *U.S. Production.* Produces and sells U.S. crude oil, natural gas, and natural gas liquids. For FRS purpose sales of U.S. crude oil can be only made to the U.S. refining/marketing segment. Natural gas and natural gas liquids can be purchased from or sold directly to U.S./foreign third parties, unconsolidated affiliates, and other U.S./foreign segments.

2. *U.S. Refining/Marketing.* Purchases raw materials from the U.S. production segment, the foreign refining/marketing segment and third parties for refining or sale to third parties. The segment also purchases directly from the foreign production segment for those companies that do not have foreign refining/marketing and import all foreign production and purchases.

3. *U.S. Pipelines.* Transports crude oil, natural gas, and natural gas liquids through Federal or State regulated pipeline operations.

4. *Foreign Production.* Produces and sells foreign crude oil, natural gas, and natural gas liquids. Oil sales are made to the foreign refining/marketing segment unless the company does not have foreign refinery operations

and imports all foreign oil production and purchases. Companies that meet these criteria may sell directly to the U.S. refining/marketing segment.

5. *Foreign Refining/Marketing.* Purchases raw materials from foreign production segments and U.S. refining/marketing segments, refines and sells to third parties, and refining/marketing segments.

6. *International Marine.* Provides marine transportation of foreign and U.S. source crude oil.

Selection of FRS Reporting Companies

Twenty-seven companies were initially notified of a requirement to file Form EIA-28. This group was initially chosen from the top 50 publicly-owned U.S. crude oil producers, in 1976, who had at least 1 percent of either the production or the reserves of oil, gas, coal, or uranium in the United States; or 1 percent of refining capacity or petroleum product sales in the United States. General Electric (GE) was originally included in the group, because of its interest in Pathfinder Mines Corporation (Pathfinder), which was a uranium-producing company. However, GE did not file Form EIA-28 because Pathfinders's financial statements were not consolidated into the financial statement of GE as a FRS reporting company. Pathfinder was not included in the FRS database.

Mergers, acquisitions and spinoffs together with the selection criteria applied to 1990 data resulted in the list of companies shown in the following tabulation.

Financial Analysis Guide

To depict the activities of the FRS companies classified by the various energy industries, several indicators have been selected to show the amounts and geographic distribution of production, profits, cash generated, accumulated investment, and annual new investment. These indicators are compared across segments, across functions within segments, and geographically. They are the same, or similar, to indicators which have been in regular use by financial analysts and economists for many years. However, to avoid potential misunderstandings, a discussion follows of the measures used, their significance, and their limitations.

All of these measures are based upon the existing framework of financial reporting now used by industry, which relies on Generally Accepted Accounting Principles (GAAP). GAAP is the set of accounting principles by which industry reflects the financial results of operations, cash flows and financial position of individual business enterprises. The two primary problems one must contend with in using present GAAP-based data is that not all companies use the same GAAP accounting methods (e.g., full cost versus successful efforts in petroleum) and GAAP is based upon historical cost accounting principles (inflationary distortions and market values are not reflected). Both of these can cause a degree of noncomparability of reported data, across companies in the case of accounting methods, and through time in the case of historical cost accounting. In spite of these problems, the data are still regarded as meaningful, especially for trend analysis.

The financial measure of the production and distribution of raw materials and refined products is operating revenues, or sales. Under GAAP this measure is based on arms-length transactions with third parties. However, in the FRS system the concept of sales has been extended to include sales from one segment to another. In such an approach, one segment's sales become another segment's costs, which must be eliminated in consolidation.

Profits are the measure of financial return for company activities. In the FRS system, profits are expressed in terms of net income, operating income, and contribution to net income. The first term applies only to the consolidated company profits, and represents income after the provision for income tax expense. Operating income applies both to the segments and to the consolidated company and is the net of operating revenues and operating expenses. Contribution to net income is meant to be the equivalent of net income for individual segments. Contribution to net income is the sum of operating income, gains (losses) from asset sales, and income from unconsolidated affiliates less income taxes. The term net income is not used for individual segment since several corporate level items are not allocated to the segment level. Interest expense is the largest item not allocated.

Accumulated investment is expressed by (1) total assets, (2) net property, plant, and equipment (PP&E), (3) investments and advances to unconsolidated affiliates, and (4) net investment in place.

Total assets is used in the context of the consolidated company figures, and is the total of the left-hand, or asset side, of the balance sheet.

Net PP&E is frequently used as a measure of resources committed by an enterprise to an industry or segment. In the energy industry, net PP&E accounts for the bulk of the consolidated assets.

Investments and advances to unconsolidated affiliates is of interest because many energy companies extend the range of their activities through subsidiaries which are less than 50-percent owned.

Finally, net investment in place is the total of: (1) net PP&E and (2) investments and advances to unconsolidated affiliates.

Nontraceables and Eliminations

One of the objectives of the FRS system is to allow economic and financial analysis of the energy industry to be performed by function. These functions, referred to in the FRS system as segments, are presented as separate entities with their own income statements. They reflect sales and purchases not only to and from unaffiliated parties, but also to and from other segments. Because the segments are not separate entities, but are part of an integrated firm, two special classifications are defined which allow reconciliation of consolidated company figures with those of the segments.

The first is the nontraceable classification, which covers those items included in the consolidated financial statements but not allocated to the segments. The second is the eliminations classification, which prevents double counting of inter-segment transactions when the segments are consolidated into total company figures.

The nontraceable classification captures assets, liabilities, revenues, and expense items, which cannot reasonably be attributed to the activities of a segment. In the FRS data, this classification reflects general overhead for the consolidated firm and financial activities which represent corporate level activities. While the financial transactions may play a key role in the firm's ability to do business, such transactions are not allocated to activities in an individual segment. The cash, corporate investments, interest income, and interest expense are examples of this.

The need for the eliminations classification arises when the product of one segment is sold to a second segment, which in turn sells the product again.

FRS Database History

The Form EIA-28, Financial Reporting System (FRS), database has existed in three formats during its 18-year history (In addition, there have been minor, periodic adjustments since 1987. The only one worth noting is the change from a Statement of Sources and Uses of Funds to a Statement of Cash Flows, effective in the 1986 reporting year). The first version of the Form EIA-28 and its database covered years 1974-1980. The second version covered years 1981-1986. The third and current version began with the 1987 reporting year and is approved through the 1992 reporting year.

The first full reporting year for the first version of the form was 1977. It consisted of 47 separate schedules containing 8,775 data elements, and was 136 pages long.[1] This version of the database contained a significant amount of detail at the consolidated level, at each line of business, and in the breadth of operating statistics.

---

[1] In order to extend the range of data back through 1974, an abbreviated version of the form was collected for the years 1974 through 1976. Almost 2,900 data elements (one-third of the total) were collected for each of these years, and consisted primarily of summary data from 26 of the 47 schedules.

However, not all of the data collected was loaded into the database. About 1,000 elements were not unique to individual companies—such as joint venture information—and were maintained only in their hard copy format.

In 1982 (for the 1981 reporting year) the form was shortened by 72 percent, to 2,468 elements. The format was still the same, with data collected at the consolidated level, four energy lines of business (petroleum, coal, nuclear, and other energy), and nonenergy. The 1981-1986 form consisted of 19 schedules, and was 35 pages long. Although data was still collected by each line of business, most of the decline was at the line of business level, where more than 81 percent of the form was eliminated compared to a 58-percent decline at the consolidated level.

In 1988 (for the 1987 reporting year) the form was shortened by another 33 percent, to 1,650 elements. The consolidated level was shortened by 32 percent, primarily by combining other energy with nuclear energy. Petroleum data declined by 10 percent, coal by 74 percent, and separate income statement schedules for the remaining lines of business (coal, nuclear and other energy, and nonenergy) were eliminated altogether (although income statements for each of these lines of business were incorporated into Schedule 5110, Consolidating Statement of Income). The form currently has 14 schedules, and is 27 pages long.

Table APP.J.III-1
Historical Results - Refining & Marketing
Domestic Petroleum Sector Operating Results
Based on DOE/EIA-0206 "Performance Profiles of Major Energy Producers"
$ Millions (then current dollars)

FRS CO. U.S. CAPITAL EXPENDITURES	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Refining	4,041	4,973	3,683	3,681	2,380	1,710	1,866	3,024	2,344	3,027
Marketing -Wholesale/Retail	1,202	1,389	1,158	2,812	1,843	1,571	2,163	2,653	2,804	2,821
Pipelines and Transportation	780	573	391	288	352	1,025	311	266	270	439
Total Refining and Marketing	6,023	6,935	5,232	6,781	4,575	4,306	4,340	5,943	5,418	6,287
FRS COMPANIES U.S. OPERATIONS										
Refining/Marketing Net Income	1,278	1,913	1,636	105	2,281	1,641	1,073	5,443	4,522	2,206
Less:Imputed RMT Interest										
Net Income After Interest Expense										
Refining/Marketing DD&A	1,948	2,194	2,187	2,393	2,432	2,555	2,685	2,732	2,883	2,974
Estimated Deferred Taxes	779	1,160	1,576	1,949	2,293	1,919	1,193	945	644	464
Gross Cash Flow	4,005	5,267	5,399	4,447	7,006	6,115	4,951	9,120	8,049	5,644
Less:Imputed RMT Dividends										
Less:Capital Expenditures	6,023	6,935	5,232	6,781	4,575	4,306	4,340	5,943	5,418	6,287
RMT Net Cash Flow	(2,018)	(1,668)	167	(2,334)	2,431	1,809	611	3,177	2,631	(643)
Cumulative Net Cash Flow	(2,018)	(3,686)	(3,519)	(5,853)	(3,422)	(1,613)	(1,002)	2,175	4,806	4,163
FRS COMPANIES NET BOOK VALUE										
Plant,Property & Equipment	47,616	50,472	52,999	53,013	55,451	59,032	61,926	60,679	63,997	69,188
Accumulated Depreciation	19,127	19,055	20,146	19,363	21,129	23,259	26,167	24,975	25,973	28,031
Net P,P & E	28,489	31,417	32,853	33,650	34,322	35,773	35,759	35,704	38,024	41,157
Investments & Advances	672	637	977	669	586	690	889	1,374	1,385	1,427
Net Investment in Place	29,161	32,054	33,830	34,319	34,908	36,463	36,648	37,078	39,409	42,584
Return on Net Investment,%	4.4%	6.0%	4.8%	0.3%	6.5%	4.5%	2.9%	14.7%	11.5%	5.2%
Net Investment in Place/Bbl. of Capacity	2,003	2,350	2,600	2,687	2,767	2,911	2,941	3,019	3,430	3,745
Additions per Bbl. of Capacity	414	508	402	531	363	344	348	484	472	553
FRS Net Income cents per gallon output	0.7	1.2	1.0	0.1	1.4	0.9	0.6	2.9	2.6	1.3
FRS Net Income ($ 1990)	1,834	2,584	2,124	131	2,735	1,917	1,215	5,930	4,718	2,206
FRS Net Income cents per gallon($ 1990)	1.1	1.6	1.3	0.1	1.6	1.1	0.7	3.2	2.7	1.3

Table APP.J.III-1
Historical Results - Transportation
Domestic Petroleum Sector Operating Results
Based on DOE/EIA-0206 "Performance Profiles of Major Energy Producers"
$ Millions (then current dollars)

FRS CO. U.S. CAPITAL EXPENDITURES	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Refining										
Marketing -Wholesale/Retail										
Pipelines and Transportation	477	418	258	643	158	254	571	344	272	467
Total Petroleum Pipelines	477	418	258	643	158	254	571	344	272	467
FRS COMPANIES U.S. OPERATIONS										
Petroleum Pipelines Net Income	1,509	1,937	1,726	1,999	1,699	1,727	1,897	1,539	1,390	1,514
Less:Imputed RMT Interest										
Net Income After Interest Expense										
Petroleum Pipelines D,D&A	530	504	509	470	504	482	581	577	568	525
Estimated Deferred Taxes	0	0	0	0	0	0	0	0	0	0
Gross Cash Flow	2,039	2,441	2,235	2,469	2,203	2,209	2,478	2,116	1,958	2,039
Less:Imputed RMT Dividends										
Less:Capital Expenditures	477	418	258	643	158	254	571	344	272	467
RMT Net Cash Flow	1,562	2,023	1,977	1,826	2,045	1,955	1,907	1,772	1,686	1,572
Cumulative Net Cash Flow	1,562	3,585	5,562	7,388	9,433	11,388	13,295	15,067	16,753	18,325
FRS COMPANIES NET BOOK VALUE										
Plant,Property & Equipment	13,423	12,722	12,790	13,026	12,915	13,441	15,408	15,773	16,312	16,686
Accumulated Depreciation	4,286	4,215	4,631	4,970	4,984	5,820	7,088	7,597	8,242	8,732
Net P,P & E	9,137	8,507	8,159	8,056	7,931	7,621	8,320	8,176	8,070	7,954
Investments & Advances	224	224	317	393	568	587	591	648	706	795
Net Investment in Place	9,361	8,731	8,476	8,449	8,499	8,208	8,911	8,824	8,776	8,749
Return on Net Investment,%	16.1%	22.2%	20.4%	23.7%	20.0%	21.0%	21.3%	17.4%	15.8%	17.3%
Net Investment in Place/Bbl. of Capacity	643	640	651	662	674	655	715	719	764	769
Additions per Bbl. of Capacity	33	31	20	50	13	20	46	28	24	41
FRS Net Income cents per gallon	0.9	1.2	1.1	1.2	1.0	1.0	1.1	0.8	0.8	0.9
FRS Net Income ($ 1990)	2,165	2,617	2,241	2,487	2,037	2,018	2,147	1,677	1,450	1,514
FRS Net Income cents per gallon($ 1990)	1.3	1.6	1.4	1.5	1.2	1.1	1.2	0.9	0.8	0.9

Table APP.J.III-1
Historical Results - Combined RMT Sectors
Domestic Petroleum Combined RMT Operating Results
Based on DOE/EIA-0206 "Performance Profiles of Major Energy Producers"
$ Millions (then current dollars)

FRS CO. U.S. CAPITAL EXPENDITURES	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Refining	4,041	4,973	3,683	3,681	2,380	1,710	1,866	3,024	2,344	3,027
Marketing -Wholesale/Retail	1,202	1,389	1,158	2,812	1,843	1,571	2,163	2,653	2,804	2,821
Pipelines and Transportation	1,257	991	649	931	510	1,279	882	610	542	906
Total Petroleum	6,500	7,353	5,490	7,424	4,733	4,560	4,911	6,287	5,690	6,754
FRS COMPANIES U.S. OPERATIONS										
RMT Net Income Before Interest	2,787	3,850	3,362	2,104	3,980	3,368	2,970	6,982	5,912	3,720
Less:Imputed RMT Interest	630	669	638	797	893	886	993	1,151	1,096	1,097
RMT Net Income After Interest	2,157	3,181	2,724	1,307	3,087	2,482	1,977	5,831	4,816	2,623
Plus:Petroleum RMT D,D&A	2,478	2,698	2,696	2,863	2,936	3,037	3,266	3,309	3,451	3,499
Plus:Estimated RMT Deferred Taxes	779	1,160	1,576	1,949	2,293	1,919	1,193	945	644	464
RMT Gross Cash Flow	5,414	7,039	6,996	6,119	8,316	7,438	6,436	10,085	8,911	6,586
Less:Imputed RMT Dividends	1,127	1,452	1,519	1,292	1,705	1,826	1,469	2,391	2,726	1,794
Less:Capital Expenditures	6,500	7,353	5,490	7,424	4,733	4,560	4,911	6,287	5,690	6,754
RMT Net Cash Flow	(2,213)	(1,766)	(13)	(2,597)	1,878	1,052	56	1,407	495	(1,962)
Cumulative RMT Net Cash Flow	(2,213)	(3,979)	(3,992)	(6,589)	(4,711)	(3,659)	(3,603)	(2,196)	(1,701)	(3,663)
FRS COMPANIES NET BOOK VALUE										
Plant,Property & Equipment	61,039	63,194	65,789	66,039	68,366	72,473	77,334	76,452	80,309	85,874
Accumulated Depreciation	23,413	23,270	24,777	24,333	26,113	29,079	33,255	32,572	34,215	36,763
Net P,P & E	37,626	39,924	41,012	41,706	42,253	43,394	44,079	43,880	46,094	49,111
Investments & Advances	896	861	1,294	1,062	1,154	1,277	1,480	2,022	2,091	2,222
Net Investment in Place	38,522	40,785	42,306	42,768	43,407	44,671	45,559	45,902	48,185	51,333
Return on Net Investment,%	7.2%	9.4%	7.9%	4.9%	9.2%	7.5%	6.5%	15.2%	12.3%	7.2%
Net Investment in Place/Bbl. of Capacity	2,646	2,990	3,251	3,349	3,441	3,566	3,656	3,738	4,194	4,514
Additions per Bbl. of Capacity	446	539	422	581	375	364	394	512	495	594
FRS Net Income cents per gallon	1.6	2.4	2.1	1.2	2.4	1.9	1.7	3.8	3.4	2.1
FRS Net Income ($ 1990)	3,999	5,201	4,364	2,617	4,773	3,935	3,362	7,607	6,168	3,720
FRS Net Income cents per gallon($ 1990)	2.3	3.2	2.7	1.5	2.9	2.2	1.9	4.1	3.5	2.1
VALUES EXTRAPOLATED TO INDUSTRY TOTALS										
Net Income (before interest)	3,607	4,973	4,333	2,690	5,088	4,347	3,936	9,258	8,356	5,375
Net Cash Flow (after cap. expend.)	(2,864)	(2,281)	(17)	(3,320)	2,401	1,358	74	1,866	700	(2,835)
Cumulative Net Cash Flow	(2,864)	(5,145)	(5,162)	(8,482)	(6,081)	(4,723)	(4,649)	(2,783)	(2,083)	(4,918)

FRSNCF.WK3

Table APP.J.III-1
Historical Results - Combined RMT Sectors
Domestic Petroleum Combined RMT Operating Results
Based on DOE/EIA-0206 "Performance Profiles of Major Energy Producers"
$ Millions (then current dollars)

	1981-1985		1986-1990		1981-1990	
FRS CO. U.S. CAPITAL EXPENDITURES	Total	Average	Total	Average	Total	Average
Refining	18,758	3,752	11,971	2,394	30,729	3,073
Marketing -Wholesale/Retail	8,404	1,681	12,012	2,402	20,416	2,042
Pipelines and Transportation	4,338	868	4,219	844	8,557	856
Total Petroleum	31,500	6,300	28,202	5,640	59,702	5,970
FRS COMPANIES U.S. OPERATIONS						
RMT Net Income Before Interest	16,083	3,217	22,952	4,590	39,035	3,904
Less:Imputed RMT Interest	3,627	725	5,223	1,045	8,850	885
RMT Net Income After Interest	12,456	2,491	17,729	3,546	30,185	3,019
Plus:Petroleum RMT D,D&A	13,671	2,734	16,562	3,312	30,233	3,023
Plus:Estimated RMT Deferred Taxes	7,757	1,551	5,165	1,033	12,922	1,292
RMT Gross Cash Flow	33,884	6,777	39,456	7,891	73,340	7,334
Less:Imputed RMT Dividends	7,095	1,419	10,206	2,041	17,301	1,730
Less:Capital Expenditures	31,500	6,300	28,202	5,640	59,702	5,970
RMT Net Cash Flow	(4,711)	(942)	1,048	210	(3,663)	(366)
Cumulative RMT Net Cash Flow						
FRS COMPANIES NET BOOK VALUE						
Plant,Property & Equipment		64,885		78,488		71,687
Accumulated Depreciation		24,381		33,177		28,779
Net P,P & E		40,504		45,312		42,908
Investments & Advances		1,053		1,818		1,436
Net Investment in Place		41,558		47,130		44,344
Return on Net Investment,%		7.7%		9.7%		8.8%
Net Investment in Place/Bbl. of Capacity		3,671		4,164		3,534
Additions per Bbl. of Capacity	2,365	473	2,345	472	3,275	472
FRS Net Income cents per gallon		1.9		2.6		2.26
FRS Net Income ($ 1990)		4,191		4,958		4,575
FRS Net Income cents per gallon($ 1990)		2.5		2.8		2.65
VALUES EXTRAPOLATED TO INDUSTRY TOTALS						
Net Income (before interest)	20,691	4,138	31,272	6,254	51,963	5,196
Net Cash Flow (after cap. expend.)	(6,081)	(1,216)	1,163	233	(4,918)	(492)
Cumulative Net Cash Flow						

TABLE APP.J.III-2

1990 Net Investment In Place
Domestic Refining, Marketing, and Transportation for FRS Companies
($ Millions–Then Current Dollars)

	Gross Investment	Accumulated DD&A	Net PP&E	Investments & Advances	Net Investment In Place
Refining	40,356	18,742	21,614*	958	22,572
Marketing	21,463	5,940	15,523	275	15,798
Transportation	7,369	3,349	4,020	194	4,214
RMT Subtotal	**69,188**	**28,031**	**41,157**	**1,427**	**42,584**
Crude & Products Pipeline	16,189	8,442	7,747	744	8,491
Other	497	290	207	51	258
RMT Total	**85,874**	**36,763**	**49,111**	**2,222**	**51,333**

* Based on FRS at 68.9 percent of total refining industry, net investment in place, for total industry estimated at $31.4 billion

FRS = Financial Reporting System
RMT = Refining, Marketing, and Transportation
DD&A = Depletion, Depreciation, and Amortization
PP&E = Property, Plant, and Equipment

Table APP.J.III-3

REFINING, MARKETING AND TRANSPORTATION SEGMENT NET INCOME
$ MILLIONS (Then Current Dollars)

FRS COMPANIES	1991 EARNINGS	1992 EARNINGS	PERCENT CHANGE
Amerada Hess Corporation (2)	(126.3)	(151.4)	#N/A
Amoco Corporation	644.0	462.0	-28%
Atlantic Richfield Co.	266.0	346.0	30%
Ashland Oil Inc. (1)	154.2	(41.5)	-127%
BP America (1)	130.8	1.2	-99%
Chevron Corporation	(153.0)	297.0	#N/A
Coastal Corporation (1)	(61.6)	(119.1)	#N/A
E.I. DuPont (Conoco)	176.0	6.0	-97%
Exxon Corporation	514.0	156.0	-70%
Fina, Inc. (1)	42.0	24.1	-43%
Kerr-McGee Corporation	20.2	(13.0)	-164%
Marathon (1)	248.6	74.4	-70%
Mobil Corporation	116.0	(144.0)	-224%
Phillips Petroleum Company (1)	88.0	102.0	16%
Shell Oil Company	(164.0)	6.0	#N/A
Sun Company	105.0	69.0	-34%
Texaco Inc.	188.0	276.0	47%
Total Petroleum (North America) Ltd. (1)	(11.5)	2.1	#N/A
Unocal Corporation	71.0	102.0	44%
GROUP TOTAL NET INCOME	**2,247.4**	**1,454.8**	**-35%**
NUMBER REPORTING	19	19	
NON-FRS COMPANIES			
CITGO Petroleum Corporation	193.1	152.3	-21%
Crown Central Petroleum Corporation	1.6	(6.3)	-494%
Diamond Shamrock	59.1	52.4	-11%
Lyondell Petrochemical	222.0	26.0	-88%
MAPCO Petroleum Inc. (1)	39.4	45.8	16%
Murphy Oil Corporation	20.9	(6.0)	-129%
Pennzoil Company (1)	62.3	40.0	-36%
Quaker State Corporation (1)	22.1	15.7	-29%
Tesoro Petroleum Co. (1)	11.5	(9.2)	-180%
TOSCO Corporation(1)	53.9	42.7	-21%
Valero (1)	82.9	85.1	3%
GROUP TOTAL NET INCOME	**768.8**	**438.5**	**-43%**
NUMBER REPORTING	11	11	
ALL COMPANY TOTAL NET INCOME	**3,016.2**	**1,893.3**	**-37%**
NUMBER REPORTING	30	30	

(1) Segment operating profit adjusted by a 38% tax rate.
(2) Company uses Average Cost and/or FIFO inventory accounting.
NA = information not available or comparison not meaningful.

SECTION IV

PROJECTED CASH FLOWS

FRSNCF.WK3

Table APP.J.IV-1
Case A
Domestic Petroleum RMT Operating Results for Large Companies
Based on DOE/EIA-0206 "Performance Profiles of Major Energy Producers"
$ Millions (then current dollars)

	Actual	Estimated	>>>----------	----------	----------	Projected	----------	----------	----------	---------->>>
FRS CO. U.S. CAPITAL EXPENDITURES	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Refining	4,760	5,211	6,192	5,595	5,820	3,519	3,661	3,808	3,961	4,119
Marketing -Wholesale/Retail	2,463	2,911	3,027	3,148	3,274	3,406	3,543	3,686	3,834	3,987
Pipelines and Transportation	1,184	925	961	1,000	1,040	1,082	1,125	1,171	1,218	1,266
Total Petroleum	8,407	9,047	10,180	9,743	10,134	8,007	8,329	8,665	9,013	9,372
FRS COMPANIES U.S. OPERATIONS										
RMT Net Income Before Interest	2,309	1,500	4,375	4,490	4,614	4,748	4,889	5,040	5,199	5,365
Less:Imputed RMT Interest	1,010	1,133	1,287	1,392	1,473	1,552	1,568	1,585	1,603	1,622
RMT Net Income After Interest	1,299	367	3,088	3,098	3,141	3,196	3,321	3,455	3,596	3,743
Plus:Petroleum RMT D,D&A	3,794	4,037	4,428	4,876	5,256	5,636	5,821	6,016	6,222	6,438
Plus:Estimated RMT Deferred Taxes	268	483	659	853	1,006	1,057	1,053	1,008	986	989
RMT Gross Cash Flow	5,361	4,887	8,175	8,827	9,403	9,889	10,195	10,479	10,804	11,170
Less:Imputed RMT Dividends	1,860	2,007	2,192	2,318	2,415	2,509	2,528	2,548	2,570	2,593
Less:Capital Expenditures	8,407	9,047	10,180	9,743	10,134	8,007	8,329	8,665	9,013	9,372
RMT Net Cash Flow	(4,906)	(6,167)	(4,197)	(3,234)	(3,146)	(627)	(662)	(734)	(779)	(795)
Cumulative RMT Net Cash Flow	(8,569)	(14,736)	(18,933)	(22,167)	(25,313)	(25,940)	(26,602)	(27,336)	(28,115)	(28,910)
FRS COMPANIES NET BOOK VALUE										
Plant,Property & Equipment	93,061	102,108	112,288	122,031	132,165	140,172	148,501	157,166	166,179	175,551
Accumulated Depreciation	40,401	44,438	48,866	53,742	58,998	64,634	70,455	76,471	82,693	89,131
Net P,P & E	52,660	57,670	63,422	68,289	73,167	75,538	78,046	80,695	83,486	86,420
Investments & Advances	2,238	2,091	2,091	2,091	2,091	2,091	2,091	2,091	2,091	2,091
Net Investment in Place	54,898	59,761	65,513	70,380	75,258	77,629	80,137	82,786	85,577	88,511
Return on Net Investment,%	4.2%	2.5%	6.7%	6.4%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%
Net Investment in Place/Bbl. of Capacity	4,850	5,280	5,788	6,218	6,649	6,858	7,080	7,314	7,560	7,820
Additions per Bbl. of Capacity	743	799	899	861	895	707	736	766	796	828
FRS Net Income cents per gallon	1.4	0.9	2.6	2.6	2.7	2.8	2.9	3.0	3.0	3.1
FRS Net Income ($ 1990)	2,219	1,386	3,889	3,838	3,791	3,750	3,712	3,679	3,648	3,620
FRS Net Income cents per gallon($ 1990)	1.3	0.8	2.3	2.3	2.2	2.2	2.2	2.2	2.1	2.1
VALUES EXTRAPOLATED TO INDUSTRY TOTALS										
Net Income (before interest)	3,356	2,180	6,359	6,526	6,707	6,901	7,106	7,326	7,557	7,798
Net Cash Flow (after cap. expend.)	(7,131)	(8,964)	(6,101)	(4,701)	(4,573)	(911)	(962)	(1,067)	(1,132)	(1,156)
Cumulative Net Cash Flow	(12,049)	(21,013)	(27,114)	(31,814)	(36,387)	(37,299)	(38,261)	(39,328)	(40,460)	(41,616)
Debt/Debt + Equity......................	40%									
Interest Rate, A/T % per annum..........	6.25%									
Dividend Rate, % per annum..............	5.00%									
Rationalization, % capacity............			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Table APP.J.IV-1
Case A
Domestic Petroleum RMT Operating Results for Large Companies
Based on DOE/EIA-0206 "Performance Profiles of Major Energy Producers"
$ Millions (then current dollars)

	1993-2000 Projection		1991-1995		1996-2000		1991-2000	
FRS CO. U.S. CAPITAL EXPENDITURES	Total	Average	Total	Average	Total	Average	Total	Average
Refining	36,675	4,584	27,578	5,516	19,068	3,814	46,646	4,665
Marketing -Wholesale/Retail	27,905	3,488	14,823	2,965	18,456	3,691	33,279	3,328
Pipelines and Transportation	8,863	1,108	5,110	1,022	5,862	1,172	10,972	1,097
Total Petroleum	73,443	9,180	47,511	9,502	43,386	8,677	90,897	9,090
FRS COMPANIES U.S. OPERATIONS								
RMT Net Income Before Interest	38,720	4,840	17,288	3,458	25,241	5,048	42,529	4,253
Less:Imputed RMT Interest	12,082	1,510	6,295	1,259	7,930	1,586	14,225	1,423
RMT Net Income After Interest	26,638	3,330	10,993	2,199	17,311	3,462	28,304	2,830
Plus:Petroleum RMT D,D&A	44,693	5,587	22,391	4,478	30,133	6,027	52,524	5,252
Plus:Estimated RMT Deferred Taxes	7,611	951	3,269	654	5,093	1,019	8,362	836
RMT Gross Cash Flow	78,942	9,868	36,653	7,331	52,537	10,507	89,190	8,919
Less:Imputed RMT Dividends	19,673	2,459	10,792	2,158	12,748	2,550	23,540	2,354
Less:Capital Expenditures	73,443	9,180	47,511	9,502	43,386	8,677	90,897	9,090
RMT Net Cash Flow	(14,174)	(1,772)	(21,650)	(4,330)	(3,597)	(719)	(25,247)	(2,525)
Cumulative RMT Net Cash Flow								
FRS COMPANIES NET BOOK VALUE								
Plant,Property & Equipment		144,257		112,331		157,514		134,922
Accumulated Depreciation		68,124		49,289		76,677		62,983
Net P,P & E		76,133		63,042		80,837		71,939
Investments & Advances		2,091		2,120		2,091		2,106
Net Investment in Place		78,224		65,162		82,928		74,045
Return on Net Investment,%		6.2%		5.3%		6.1%		5.7%
Net Investment in Place/Bbl. of Capacity		6,911		5,757		7,326		6,542
Additions per Bbl. of Capacity	6,488	811	4,197	839	3,833	767		803
FRS Net Income cents per gallon		2.8		2.0		3.0		2.5
FRS Net Income ($ 1990)		3,741		3,025		3,682		3,353
FRS Net Income cents per gallon($ 1990)		2.2		1.8		2.2		2.0
VALUES EXTRAPOLATED TO INDUSTRY TOTALS								
Net Income (before interest)	56,281	7,035	25,129	5,026	36,689	7,338	61,818	6,182
Net Cash Flow (after cap. expend.)	(20,602)	(2,575)	(31,469)	(6,294)	(5,228)	(1,046)	(36,697)	(3,670)
Cumulative Net Cash Flow								

Debt/Debt + Equity......................	40%	Cost of capital recovery.........................	0%
Interest Rate, A/T % per annum..........	6.25%	Pct. of 1981-1991 Average Net Income............	100%
Dividend Rate, % per annum..............	5.00%	Under-recovery of added refining expenses........	0%
Rationalization, % capacity.............		Rationalization,% capacity.......................	0%

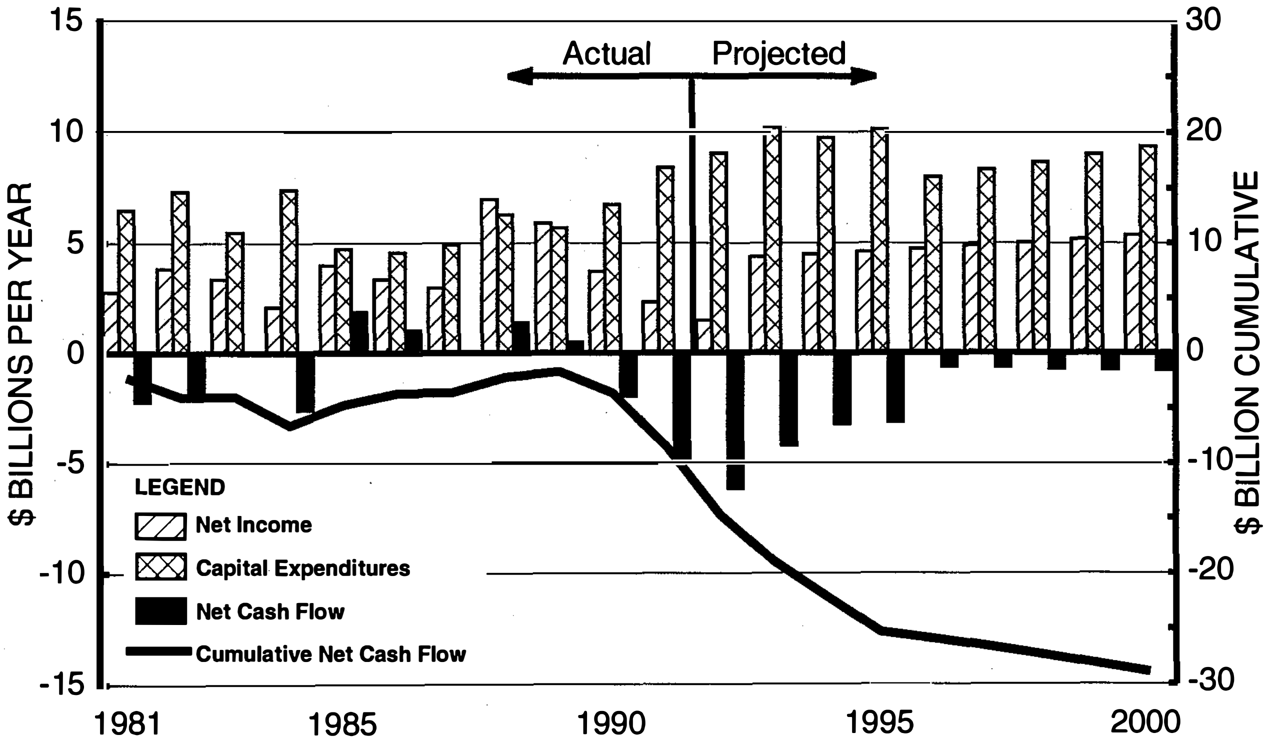
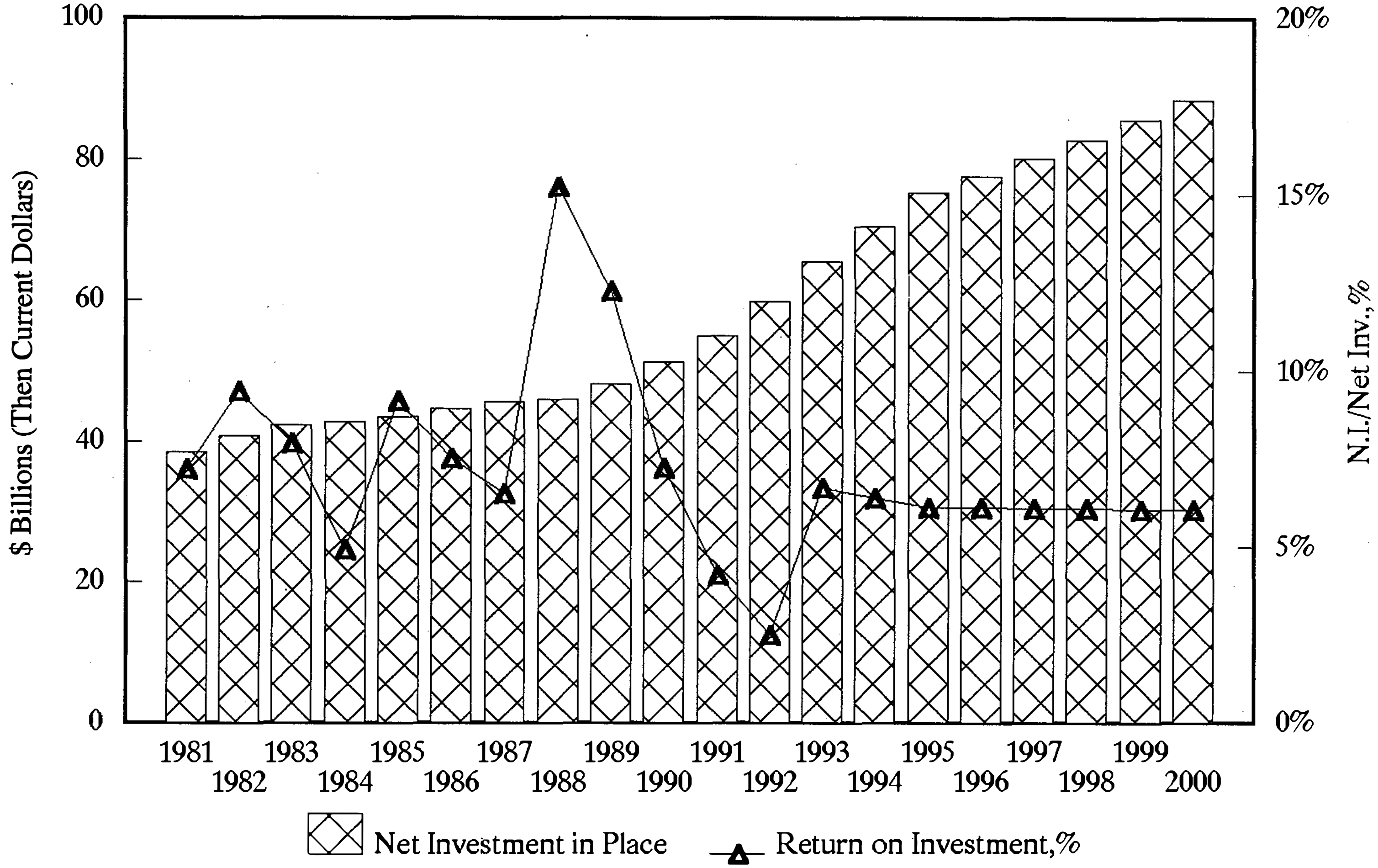


Figure APP. J.IV-1. Cumulative Net Cash Flow—Case A (Then Current Dollars) U.S. Refining, Marketing and Transportation for FRS Companies.

Note: Net income for 1993-2000 equals the 1981-1990 average in real terms.
Full passthrough of increased refining expenses but no cost of capital recovery.

Return on Net Investment

for FRS Companies Domestic Refining, Marketing & Transportation



Net income for 1993–2000 equals the 1981–1990 average in real terms.
Full passthrough of increased expenses but no capital charge recovery. (Case A)

FRSNCF.WK3

Table APP.J.IV-2
Case B
Domestic Petroleum RMT Operating Results for Large Companies
Based on DOE/EIA-0206 "Performance Profiles of Major Energy Producers"
$ Millions (then current dollars)

	Actual	Estimated	>>>---			Projected				--->>>
FRS CO. U.S. CAPITAL EXPENDITURES	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Refining	4,760	5,211	6,192	5,595	5,820	3,519	3,661	3,808	3,961	4,119
Marketing -Wholesale/Retail	2,463	2,911	3,027	3,148	3,274	3,406	3,543	3,686	3,834	3,987
Pipelines and Transportation	1,184	925	961	1,000	1,040	1,082	1,125	1,171	1,218	1,266
Total Petroleum	8,407	9,047	10,180	9,743	10,134	8,007	8,329	8,665	9,013	9,372
FRS COMPANIES U.S. OPERATIONS										
RMT Net Income Before Interest	2,309	1,500	4,873	5,267	5,682	6,037	6,325	6,629	6,947	7,278
Less:Imputed RMT Interest	1,010	1,133	1,287	1,379	1,440	1,490	1,470	1,445	1,416	1,382
RMT Net Income After Interest	1,299	367	3,586	3,888	4,242	4,547	4,855	5,184	5,531	5,896
Plus:Petroleum RMT D,D&A	3,794	4,037	4,428	4,876	5,256	5,636	5,821	6,016	6,222	6,438
Plus:Estimated RMT Deferred Taxes	268	483	659	853	1,006	1,057	1,053	1,008	986	989
RMT Gross Cash Flow	5,361	4,887	8,673	9,617	10,504	11,240	11,729	12,208	12,739	13,323
Less:Imputed RMT Dividends	1,860	2,007	2,192	2,303	2,376	2,436	2,412	2,382	2,347	2,306
Less:Capital Expenditures	8,407	9,047	10,180	9,743	10,134	8,007	8,329	8,665	9,013	9,372
RMT Net Cash Flow	(4,906)	(6,167)	(3,699)	(2,429)	(2,006)	797	988	1,161	1,379	1,645
Cumulative RMT Net Cash Flow	(8,569)	(14,736)	(18,435)	(20,864)	(22,870)	(22,073)	(21,085)	(19,924)	(18,545)	(16,900)
FRS COMPANIES NET BOOK VALUE										
Plant,Property & Equipment	93,061	102,108	112,288	122,031	132,165	140,172	148,501	157,166	166,179	175,551
Accumulated Depreciation	40,401	44,438	48,866	53,742	58,998	64,634	70,455	76,471	82,693	89,131
Net P,P & E	52,660	57,670	63,422	68,289	73,167	75,538	78,046	80,695	83,486	86,420
Investments & Advances	2,238	2,091	2,091	2,091	2,091	2,091	2,091	2,091	2,091	2,091
Net Investment in Place	54,898	59,761	65,513	70,380	75,258	77,629	80,137	82,786	85,577	88,511
Return on Net Investment,%	4.2%	2.5%	7.4%	7.5%	7.6%	7.8%	7.9%	8.0%	8.1%	8.2%
Net Investment in Place/Bbl. of Capacity	4,850	5,280	5,788	6,218	6,649	6,858	7,080	7,314	7,560	7,820
Additions per Bbl. of Capacity	743	799	899	861	895	707	736	766	796	828
FRS Net Income cents per gallon	1.4	0.9	2.9	3.1	3.3	3.5	3.7	3.9	4.1	4.3
FRS Net Income ($ 1990)	2,219	1,386	4,332	4,502	4,669	4,769	4,803	4,839	4,875	4,911
FRS Net Income cents per gallon($ 1990)	1.3	0.8	2.5	2.6	2.7	2.8	2.8	2.8	2.9	2.9
VALUES EXTRAPOLATED TO INDUSTRY TOTALS										
Net Income (before interest)	3,356	2,180	7,083	7,656	8,259	8,775	9,194	9,636	10,098	10,579
Net Cash Flow (after cap. expend.)	(7,131)	(8,964)	(5,377)	(3,531)	(2,916)	1,158	1,436	1,688	2,004	2,391
Cumulative Net Cash Flow	(12,049)	(21,013)	(26,390)	(29,921)	(32,836)	(31,678)	(30,242)	(28,554)	(26,550)	(24,159)
Debt/Debt + Equity......................	40%									
Interest Rate, A/T % per annum..........	6.25%									
Dividend Rate, % per annum..............	5.00%									
Rationalization, % capacity............			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FRSNCF.WK3

Table APP.J.IV-2
Case B
Domestic Petroleum RMT Operating Results for Large Companies
Based on DOE/EIA-0206 "Performance Profiles of Major Energy Producers"
$ Millions (then current dollars)

	1993-2000 Projection		1991-1995		1996-2000		1991-2000	
FRS CO. U.S. CAPITAL EXPENDITURES	Total	Average	Total	Average	Total	Average	Total	Average
Refining	36,675	4,584	27,578	5,516	19,068	3,814	46,646	4,665
Marketing -Wholesale/Retail	27,905	3,488	14,823	2,965	18,456	3,691	33,279	3,328
Pipelines and Transportation	8,863	1,108	5,110	1,022	5,862	1,172	10,972	1,097
Total Petroleum	73,443	9,180	47,511	9,502	43,386	8,677	90,897	9,090
FRS COMPANIES U.S. OPERATIONS								
RMT Net Income Before Interest	49,038	6,130	19,631	3,926	33,216	6,643	52,847	5,285
Less:Imputed RMT Interest	11,309	1,414	6,249	1,250	7,203	1,441	13,452	1,345
RMT Net Income After Interest	37,729	4,716	13,382	2,676	26,013	5,203	39,395	3,940
Plus:Petroleum RMT D,D&A	44,693	5,587	22,391	4,478	30,133	6,027	52,524	5,252
Plus:Estimated RMT Deferred Taxes	7,611	951	3,269	654	5,093	1,019	8,362	836
RMT Gross Cash Flow	90,033	11,254	39,042	7,808	61,239	12,248	100,281	10,028
Less:Imputed RMT Dividends	18,754	2,344	10,738	2,148	11,883	2,377	22,621	2,262
Less:Capital Expenditures	73,443	9,180	47,511	9,502	43,386	8,677	90,897	9,090
RMT Net Cash Flow	(2,164)	(271)	(19,207)	(3,841)	5,970	1,194	(13,237)	(1,324)
Cumulative RMT Net Cash Flow								
FRS COMPANIES NET BOOK VALUE								
Plant,Property & Equipment		144,257		112,331		157,514		134,922
Accumulated Depreciation		68,124		49,289		76,677		62,983
Net P,P & E		76,133		63,042		80,837		71,939
Investments & Advances		2,091		2,120		2,091		2,106
Net Investment in Place		78,224		65,162		82,928		74,045
Return on Net Investment,%		7.8%		6.0%		8.0%		7.1%
Net Investment in Place/Bbl. of Capacity		6,911		5,757		7,326		6,542
Additions per Bbl. of Capacity	6,488	811	4,197	839	3,833	767		803
FRS Net Income cents per gallon		3.6		2.3		3.9		3.1
FRS Net Income ($ 1990)		4,712		3,421		4,839		4,130
FRS Net Income cents per gallon($ 1990)		2.8		2.0		2.8		2.4
VALUES EXTRAPOLATED TO INDUSTRY TOTALS								
Net Income (before interest)	71,279	8,910	28,534	5,707	48,281	9,656	76,815	7,682
Net Cash Flow (after cap. expend.)	(3,145)	(393)	(27,918)	(5,584)	8,678	1,736	(19,240)	(1,924)
Cumulative Net Cash Flow								

Debt/Debt + Equity......................	40%	Cost of capital recovery.........................	100%
Interest Rate, A/T % per annum..........	6.25%	Pct. of 1981-1991 Average Net Income.............	100%
Dividend Rate, % per annum..............	5.00%	Under-recovery of added refining expenses........	0%
Rationalization, % capacity.............		Rationalization,% capacity.......................	0%

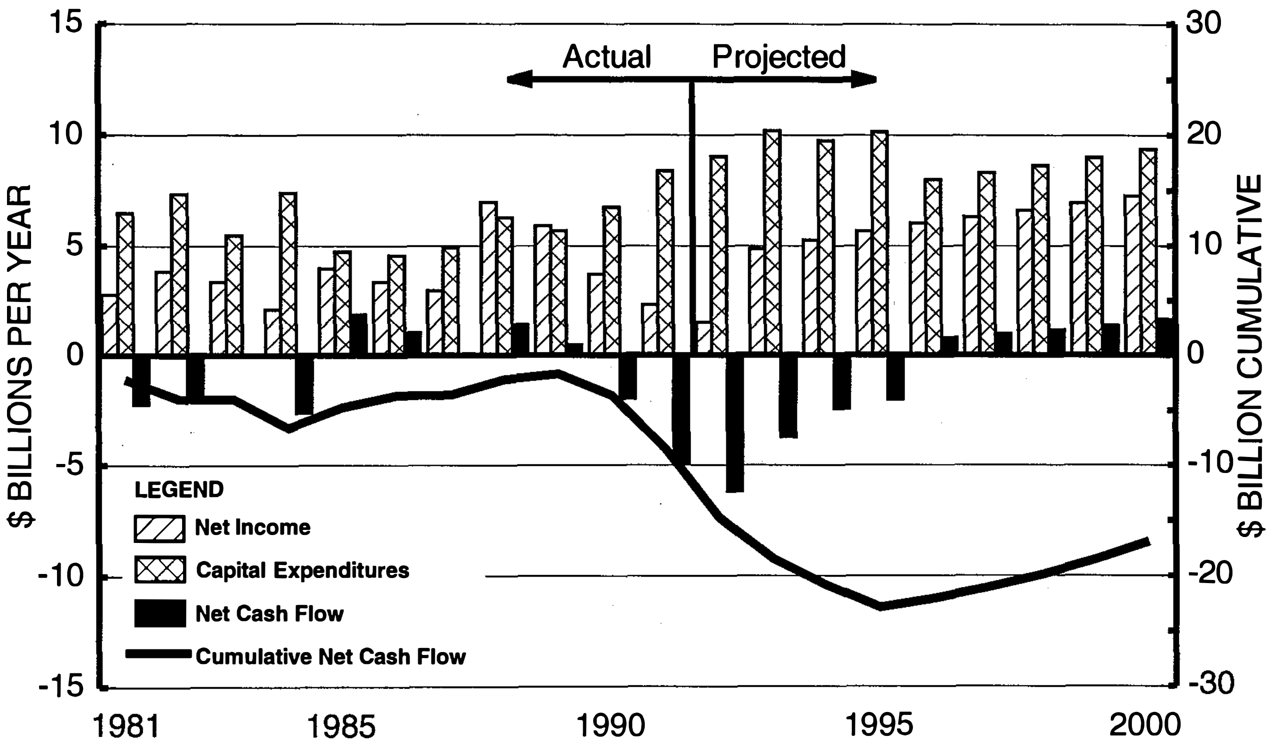


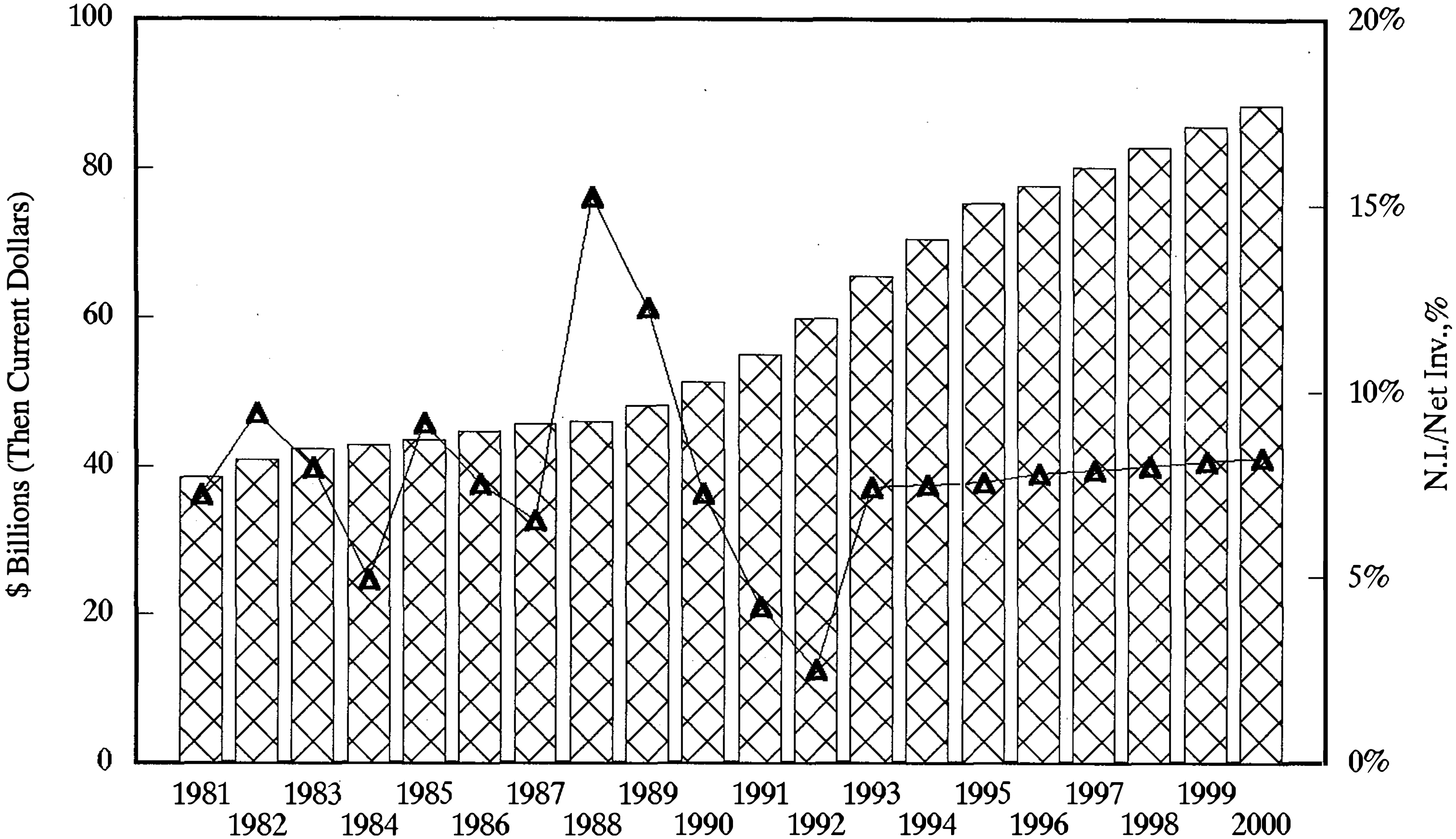
Figure APP. J.IV-3. Cumulative Net Cash Flow—Case B (Then Current Dollars) U.S. Refining, Marketing and Transportation for FRS Companies.

Note: Net income equal to Case A plus cost of capital on new environmental expenditures.

APP.J.IV-4

Return on Net Investment

for FRS Companies Domestic Refining, Marketing & Transportation



Net income for 1993–2000 equals the 1981–1990 average in real terms.
Full passthrough of increased expenses and capital charge recovery. (Case B)

FRSNCF.WK3

Table APP.J.IV-3
Case C
Domestic Petroleum RMT Operating Results for Large Companies
Based on DOE/EIA-0206 "Performance Profiles of Major Energy Producers"
$ Millions (then current dollars)

	Actual	Estimated	>>>----------	----------	----------	---------- Projected	----------	----------	----------	---------->>>
FRS CO. U.S. CAPITAL EXPENDITURES	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Refining	4,760	5,211	6,192	5,595	5,820	3,519	3,661	3,808	3,961	4,119
Marketing -Wholesale/Retail	2,463	2,911	3,027	3,148	3,274	3,406	3,543	3,686	3,834	3,987
Pipelines and Transportation	1,184	925	961	1,000	1,040	1,082	1,125	1,171	1,218	1,266
Total Petroleum	8,407	9,047	10,180	9,743	10,134	8,007	8,329	8,665	9,013	9,372
FRS COMPANIES U.S. OPERATIONS										
RMT Net Income Before Interest	2,309	1,500	6,187	6,634	7,104	7,516	7,864	8,229	8,611	9,010
Less:Imputed RMT Interest	1,010	1,133	1,287	1,347	1,372	1,383	1,320	1,249	1,169	1,079
RMT Net Income After Interest	1,299	367	4,900	5,287	5,732	6,133	6,544	6,980	7,442	7,931
Plus:Petroleum RMT D,D&A	3,794	4,037	4,428	4,876	5,256	5,636	5,821	6,016	6,222	6,438
Plus:Estimated RMT Deferred Taxes	268	483	659	853	1,006	1,057	1,053	1,008	986	989
RMT Gross Cash Flow	5,361	4,887	9,987	11,016	11,994	12,826	13,418	14,004	14,650	15,358
Less:Imputed RMT Dividends	1,860	2,007	2,192	2,264	2,294	2,307	2,232	2,146	2,050	1,942
Less:Capital Expenditures	8,407	9,047	10,180	9,743	10,134	8,007	8,329	8,665	9,013	9,372
RMT Net Cash Flow	(4,906)	(6,167)	(2,385)	(991)	(434)	2,512	2,857	3,193	3,587	4,044
Cumulative RMT Net Cash Flow	(8,569)	(14,736)	(17,121)	(18,112)	(18,546)	(16,034)	(13,177)	(9,984)	(6,397)	(2,353)
FRS COMPANIES NET BOOK VALUE										
Plant,Property & Equipment	93,061	102,108	112,288	122,031	132,165	140,172	148,501	157,166	166,179	175,551
Accumulated Depreciation	40,401	44,438	48,866	53,742	58,998	64,634	70,455	76,471	82,693	89,131
Net P,P & E	52,660	57,670	63,422	68,289	73,167	75,538	78,046	80,695	83,486	86,420
Investments & Advances	2,238	2,091	2,091	2,091	2,091	2,091	2,091	2,091	2,091	2,091
Net Investment in Place	54,898	59,761	65,513	70,380	75,258	77,629	80,137	82,786	85,577	88,511
Return on Net Investment,%	4.2%	2.5%	9.4%	9.4%	9.4%	9.7%	9.8%	9.9%	10.1%	10.2%
Net Investment in Place/Bbl. of Capacity	4,850	5,280	5,788	6,218	6,649	6,858	7,080	7,314	7,560	7,820
Additions per Bbl. of Capacity	743	799	899	861	895	707	736	766	796	828
FRS Net Income cents per gallon	1.4	0.9	3.6	3.9	4.2	4.4	4.6	4.8	5.1	5.3
FRS Net Income ($ 1990)	2,219	1,386	5,500	5,670	5,837	5,937	5,971	6,007	6,043	6,080
FRS Net Income cents per gallon($ 1990)	1.3	0.8	3.2	3.3	3.4	3.5	3.5	3.5	3.5	3.6
VALUES EXTRAPOLATED TO INDUSTRY TOTALS										
Net Income (before interest)	3,356	2,180	8,993	9,643	10,326	10,925	11,431	11,961	12,516	13,096
Net Cash Flow (after cap. expend.)	(7,131)	(8,964)	(3,467)	(1,440)	(631)	3,651	4,153	4,641	5,214	5,878
Cumulative Net Cash Flow	(12,049)	(21,013)	(24,480)	(25,920)	(26,551)	(22,900)	(18,747)	(14,106)	(8,892)	(3,014)
Debt/Debt + Equity......................	40%									
Interest Rate, A/T % per annum..........	6.25%									
Dividend Rate, % per annum..............	5.00%									
Rationalization, % capacity.............			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Table APP.J.IV-3
Case C
Domestic Petroleum RMT Operating Results for Large Companies
Based on DOE/EIA-0206 "Performance Profiles of Major Energy Producers"
$ Millions (then current dollars)

	1993-2000 Projection		1991-1995		1996-2000		1991-2000	
FRS CO. U.S. CAPITAL EXPENDITURES	Total	Average	Total	Average	Total	Average	Total	Average
Refining	36,675	4,584	27,578	5,516	19,068	3,814	46,646	4,665
Marketing -Wholesale/Retail	27,905	3,488	14,823	2,965	18,456	3,691	33,279	3,328
Pipelines and Transportation	8,863	1,108	5,110	1,022	5,862	1,172	10,972	1,097
Total Petroleum	73,443	9,180	47,511	9,502	43,386	8,677	90,897	9,090
FRS COMPANIES U.S. OPERATIONS								
RMT Net Income Before Interest	61,155	7,644	23,734	4,747	41,230	8,246	64,964	6,496
Less:Imputed RMT Interest	10,206	1,276	6,149	1,230	6,200	1,240	12,349	1,235
RMT Net Income After Interest	50,949	6,369	17,585	3,517	35,030	7,006	52,615	5,262
Plus:Petroleum RMT D,D&A	44,693	5,587	22,391	4,478	30,133	6,027	52,524	5,252
Plus:Estimated RMT Deferred Taxes	7,611	951	3,269	654	5,093	1,019	8,362	836
RMT Gross Cash Flow	103,253	12,907	43,245	8,649	70,256	14,051	113,501	11,350
Less:Imputed RMT Dividends	17,427	2,178	10,617	2,123	10,677	2,135	21,294	2,129
Less:Capital Expenditures	73,443	9,180	47,511	9,502	43,386	8,677	90,897	9,090
RMT Net Cash Flow	12,383	1,548	(14,883)	(2,977)	16,193	3,239	1,310	131
Cumulative RMT Net Cash Flow								
FRS COMPANIES NET BOOK VALUE								
Plant,Property & Equipment		144,257		112,331		157,514		134,922
Accumulated Depreciation		68,124		49,289		76,677		62,983
Net P,P & E		76,133		63,042		80,837		71,939
Investments & Advances		2,091		2,120		2,091		2,106
Net Investment in Place		78,224		65,162		82,928		74,045
Return on Net Investment,%		9.8%		7.3%		9.9%		8.8%
Net Investment in Place/Bbl. of Capacity		6,911		5,757		7,326		6,542
Additions per Bbl. of Capacity	6,488	811	4,197	839	3,833	767		803
FRS Net Income cents per gallon		4.5		2.8		4.8		3.8
FRS Net Income ($ 1990)		5,880		4,122		6,007		5,065
FRS Net Income cents per gallon($ 1990)		3.4		2.4		3.5		3.0
VALUES EXTRAPOLATED TO INDUSTRY TOTALS								
Net Income (before interest)	88,891	11,111	34,498	6,900	59,929	11,986	94,428	9,443
Net Cash Flow (after cap. expend.)	17,999	2,250	(21,633)	(4,327)	23,537	4,707	1,904	190
Cumulative Net Cash Flow								

Debt/Debt + Equity......................	40%	Cost of capital recovery.........................	100%
Interest Rate, A/T % per annum..........	6.25%	Pct. of 1981-1991 Average Net Income............	146%
Dividend Rate, % per annum..............	5.00%	Under-recovery of added refining expenses........	0%
Rationalization, % capacity.............		Rationalization,% capacity.......................	0%

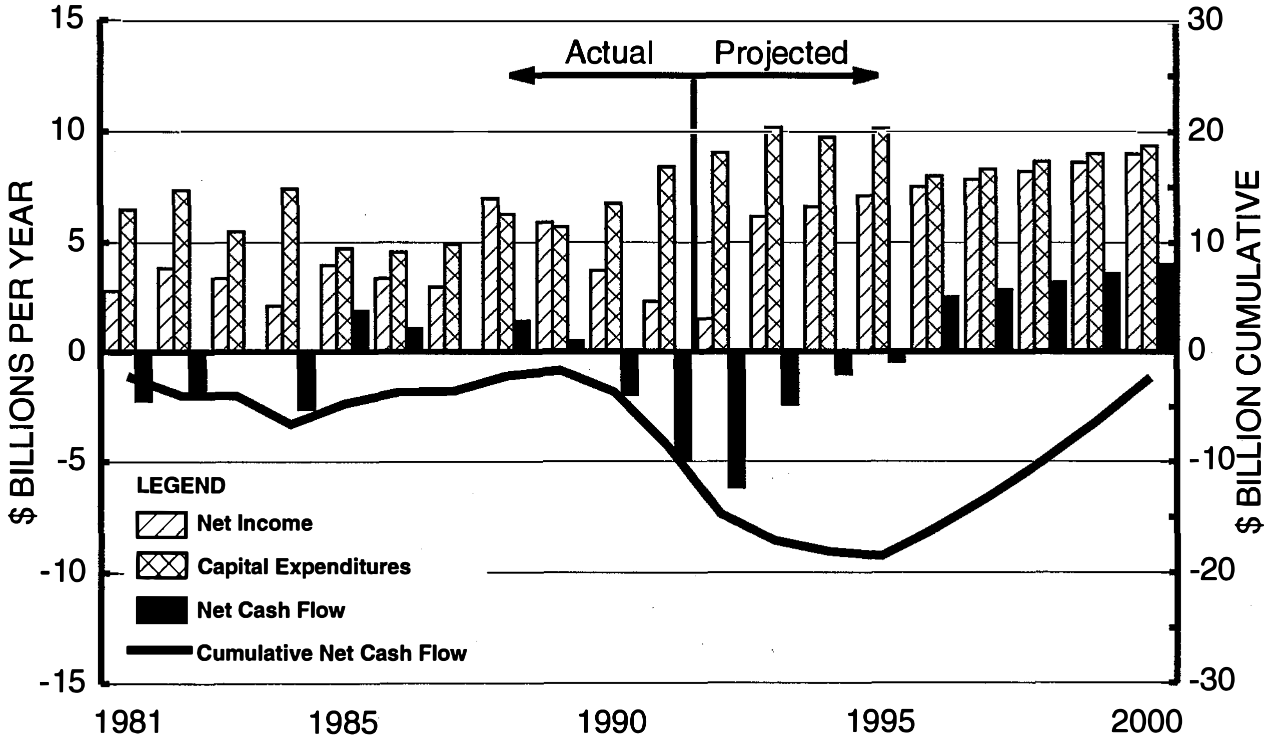
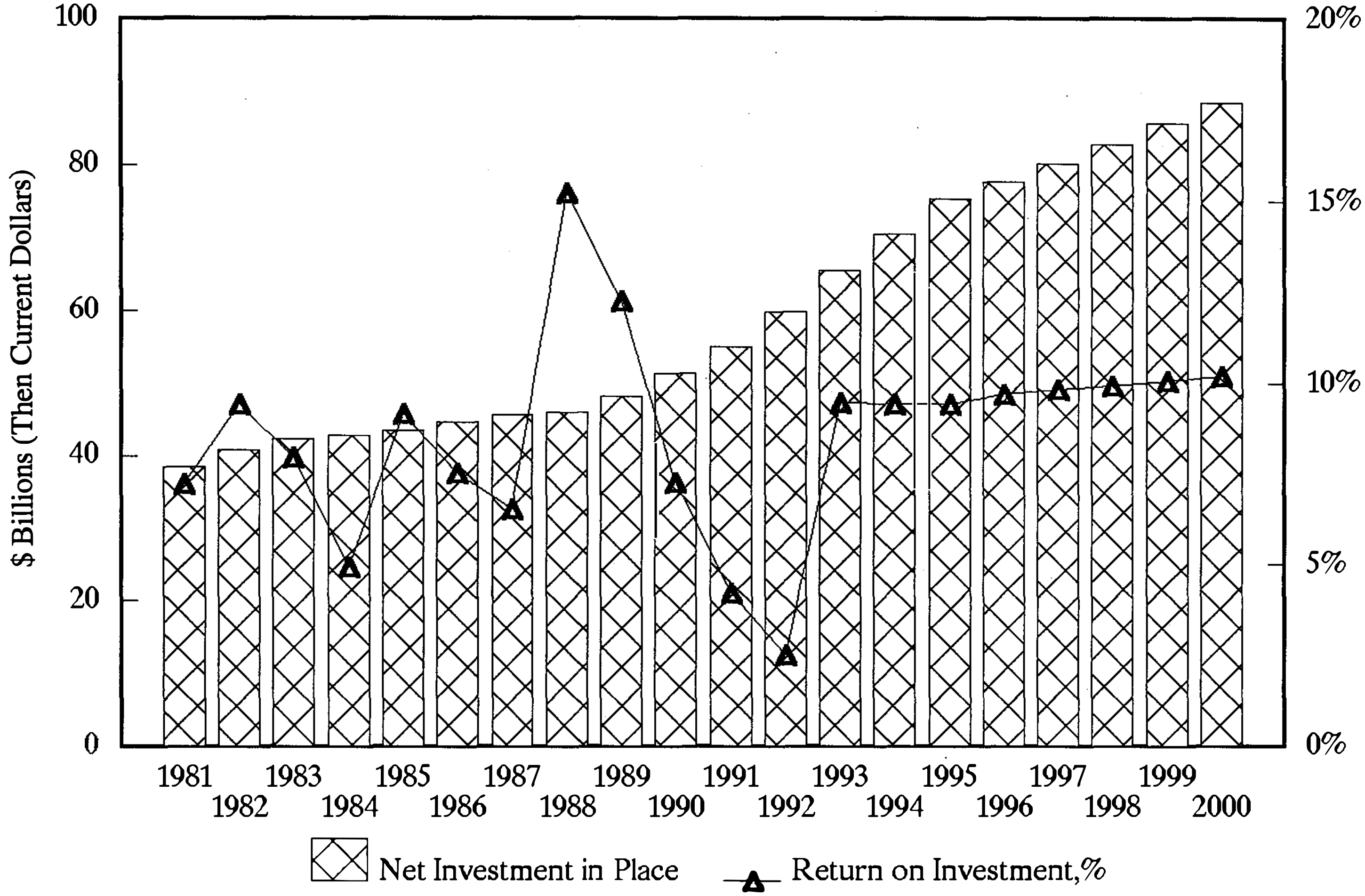


Figure APP. J.IV-5. Cumulative Net Cash Flow—Case C (Then Current Dollars) U.S. Refining, Marketing and Transportation for FRS Companies.

Note: Net income sufficient to provide average ROI for 1991-2000 equals average ROI for 1981-1990.

Return on Net Investment

for FRS Companies Domestic Refining,Marketing & Transportation



Net income for 1993–2000 equals 1.46 times the 1981–1990 average in real terms to make 1991–2000 average return on investment equal to the 1981–190 average of 8.8%. (Case C)

Consequences of Excess Capacity in A Competitive Market

The alternative scenarios of the NPC study result in decreasing refinery utilization in all cases to 1995. With industry earnings in the 1990-1992 period substantially below the ten year average, capacity reduction has been on the rise. This note makes explicit the reasons such shutdowns tend to improve the returns in an industry with a simplified example. It also underlines the difficulty in making estimates of the relation between earnings and utilization.

A competitive market is considered to have excess supply capacity when market price is less than the producers' lowest average cost of production. Here cost of production includes a cost of capital. When producers have slightly different costs of production, the least efficient (excess) capacity exits the market and market price increases with a corresponding decrease in total demand. However because the total market capacity has decreased, the remaining suppliers have increases in plant demand, i.e., industry utilization increases.

Figures APP.J.IV-7, 8 and 9 illustrate graphically this circumstance. Consider an industry with eleven plants of equal capacity and approximately equal costs of production shown in Figure APP.J.IV-7. The total market demand, D, for the eleven firm industry is at equilibrium at 1100 units and C_0 price on supply curve $S_{n=11}$ (Figure App.J.IV-8). The supply curve for the industry is just the (horizontal) sum of all the marginal cost curves of suppliers in the industry. Each plant operates at 100 units of output. This is below the level where marginal cost equals average cost (105 units of output) so every plant is not covering all its economic costs.

If there is variation in costs between suppliers, one supplier must be less efficient and will be the most likely to exit the industry. The industry supply curve is then $S_{n=10}$ and the equilibrium quantity is 1050 at price C_1. Now each remaining plant will operate closer to its optimal point where marginal and average cost are equal. At this point, output per plant is 105 units (Figure APP.J.IV-9).

The results of the exit of a plant from the industry has been to raise the suppliers' income to cover all costs, decrease demand, and increase industry utilization.

The functional relation between income and utilization described above is not supported by simple regressions. As illustrated, the change in income is dependent on how demand changes with price. But there are many markets for the outputs of refineries, making estimation uncertain.

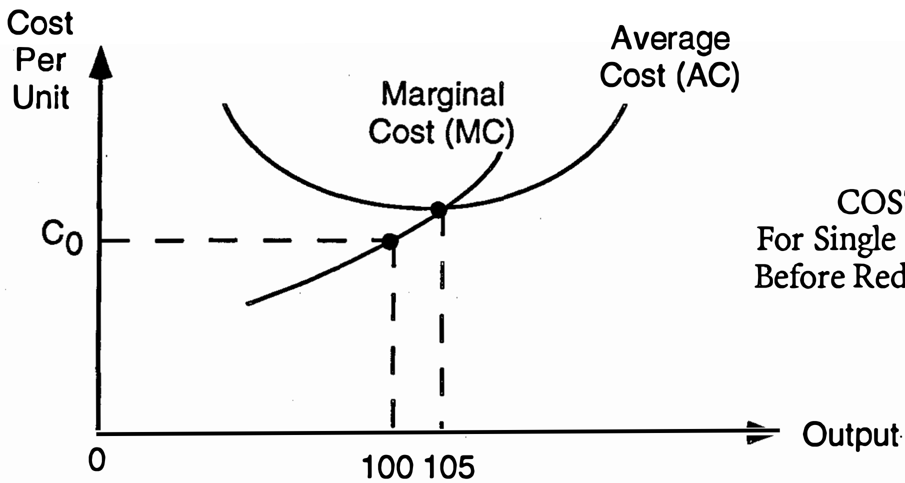


Figure APP.J.IV-7

COST OF PRODUCTION
For Single Plant (in 11 Plant Industry)
Before Reduction in Industry Capacity

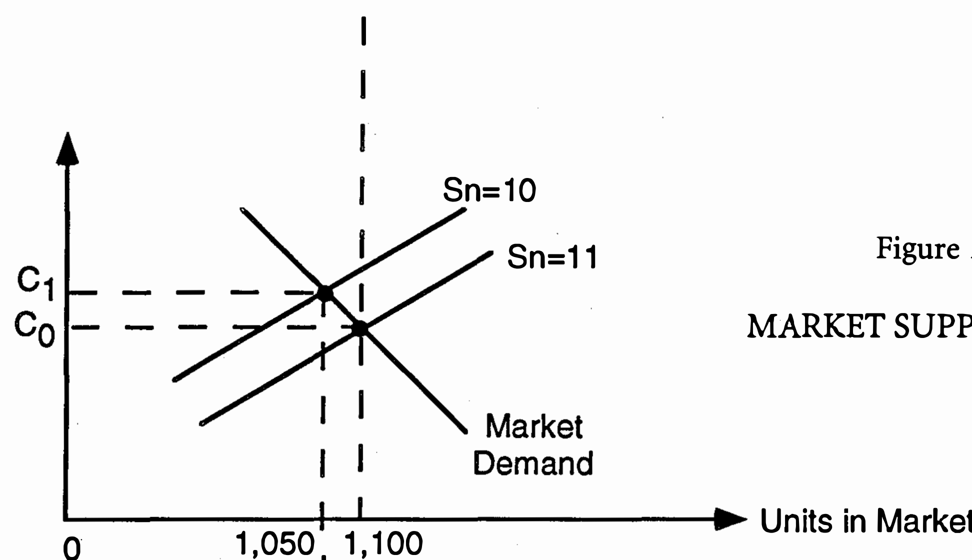


Figure APP.J.IV-8

MARKET SUPPLY AND DEMAND

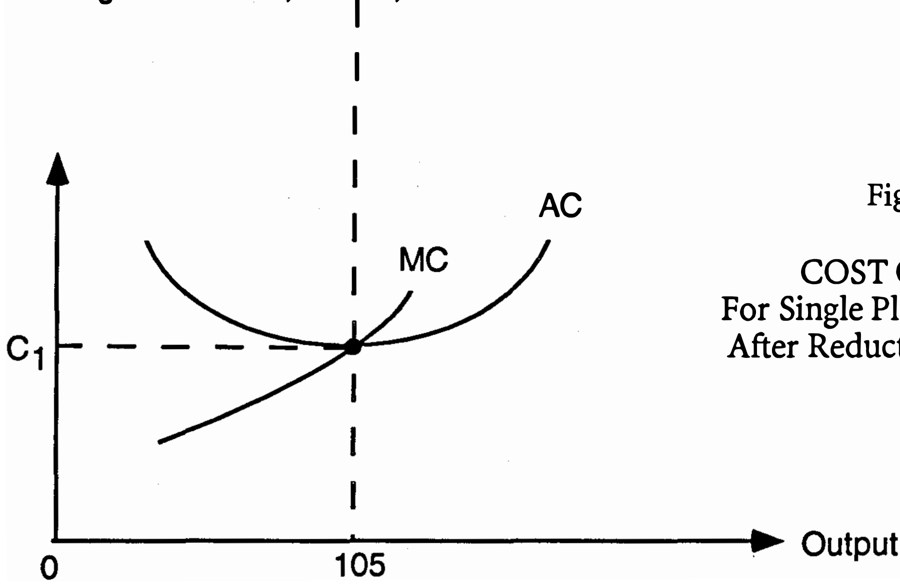


Figure APP.J.IV-9

COST OF PRODUCTION
For Single Plant (in 10 plant industry)
After Reduction in Industry Capacity

Impact of an Increase in Utilization
in a Competitive Market

SECTION V

IMPLICATIONS FOR CONSUMERS

CONSUMER DEMAND, COST INCREASES, AND SUPPLIER INCOME

Consumer Demand, Cost Increases, and Supplier Income

The efforts to comply with governmental regulations (covering both those affecting refinery emissions and product quality) result in added costs. Everything else being equal, the added cost to the consumer will reduce demand. The required oxygenated motor gasoline will reduce the amount of traditional fuel components in motor fuel, effectively reducing the amount of refining capacity needed. The reduction in required product for these two reasons will result in shutting down of capacity by rationalization of marginal refineries. And the total earnings of the remaining industry will be reduced.

Figure APP.J.V-1 shows the qualitative impact on the industry of the added costs. The industry supply curve is the aggregate of the individual cost-volume curve described in Chapter Three. The added costs are layered on the base supply curve. With the higher costs, consumers demand less product. The result is a reduction in capacity required.

After rationalization, the refineries providing the marginal product in various regions will be more efficient than the refineries removed from operations, lowering all costs but those of regulation. Consumer costs will be higher by the added costs of regulation, decreased only by the lower base costs of the new marginal refineries. But this portion of the costs offset by the improved efficiency reduces the average net income for the remaining refineries (see Figure APP.J.V-3) compared to before the added cost (see Figure APP.J.V-2).

The implication of lower returns for the industry as a whole is greater instability, arising for more pronounced capacity building cycles. A greater portion of the industry will not be considered suitable for investment, tending to contract capacity to the point where capacity decline and/or demand growth results in sharply rising demand for capacity and returns on investment rise steeply. The result invariably is overbuilding and a collapse in returns, dropping industry returns lower.

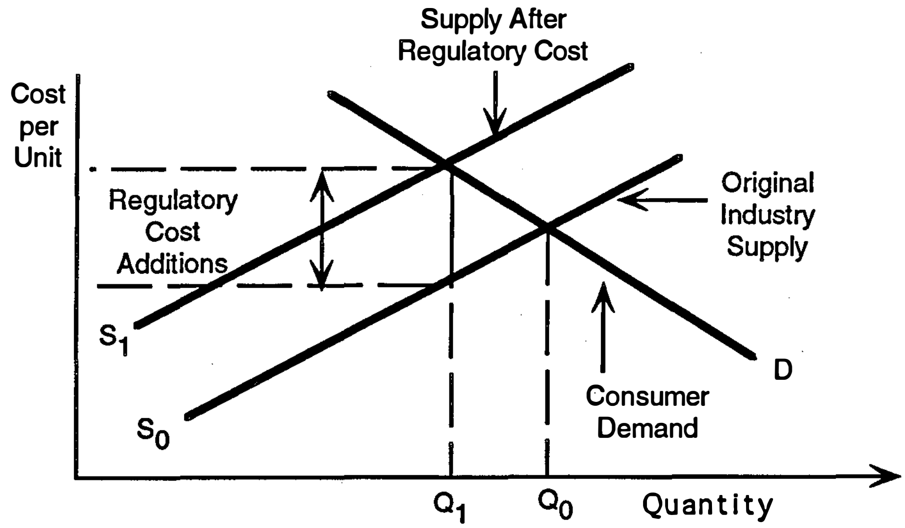


Figure APP.J.V-1

Shift of Market Equilibrium with Added Cost.

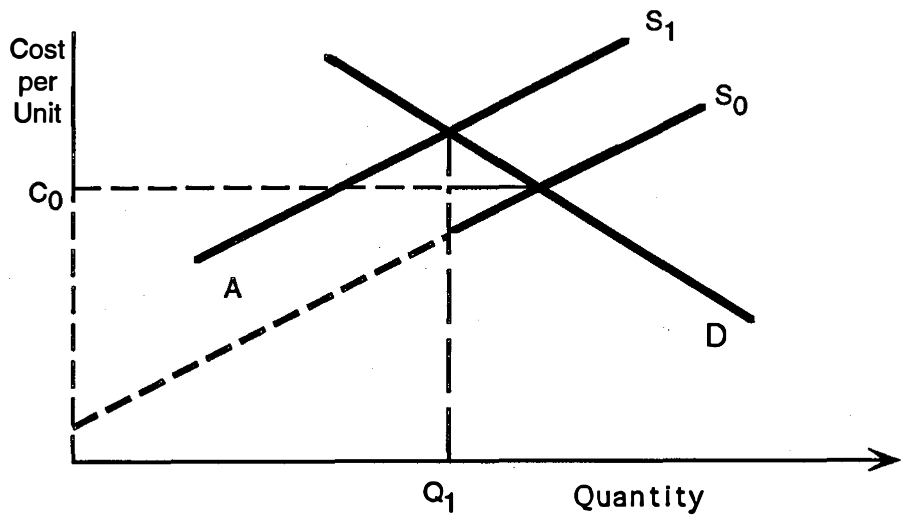


Figure APP.J.V-2

Surviving Suppliers' Earnings <u>Before</u> Added Costs.

Area A = Earnings of surviving suppliers before added costs – – – – – –

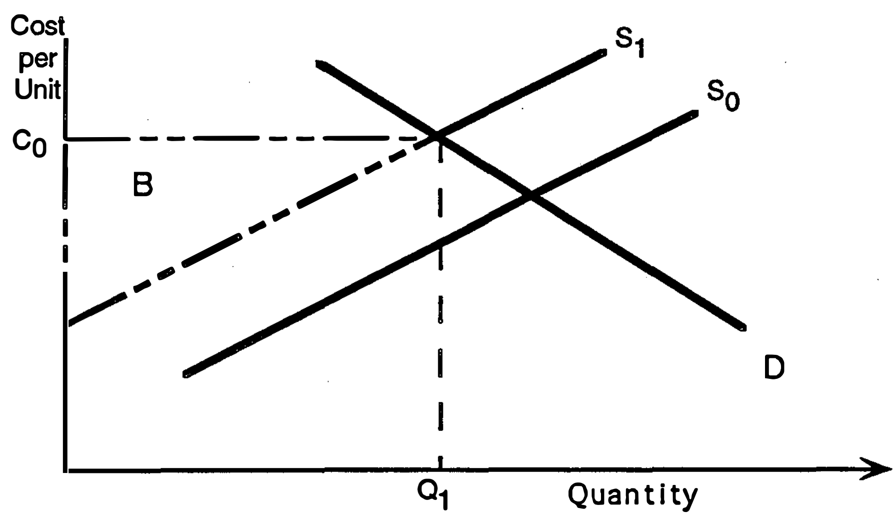


Figure APP.J.V-3

Surviving Suppliers' Earnings <u>After</u> Added Costs.

Area B = Earnings of surviving suppliers after added costs —— – – ——

Note: Area B is less than Area A - i.e., surviving suppliers' earnings decline with "full pass through" of added costs.

APPENDIX K

U.S. REFINING STATIONARY SOURCE FACILITIES

(APPENDIX TO CHAPTER TWO)

SECTION I

STUDY SUPPORT ATTACHMENTS

Paul W. Lashbrooke
Vice President
Refining and Research and Engineering

Conoco Inc.
P.O. Box 2197
Houston, TX 77252

March 10, 1992

J. H. Matkin
Chevron Research and Technology Company
Post Office Box 1627-0627
Richmond, California 94802-0627

W. R. Finger
Exxon Company, U.S.A.
Post Office Box 2180
Room 2819
Houston, Texas 77252-2180

T. S. McGowin
Texaco Refining and Marketing, Inc.
Post Office Box 1404
Houston Texas, 77251-1404

NATIONAL PETROLEUM COUNCIL
REFINING STUDY

Gentlemen:

The Facilities Task Group of the NPC Coordinating Subcommittee has developed the attached information to help assure investment and operating cost compatibility among our several study efforts.

Turner-Mason, Pace and Bechtel all provided input for these determinations and the attachment is designed to be used by them as you see fit. Our Messrs. Marcinek, Gray and Bruce have received total cooperation from Mr. Warden and Mr. Zarker to accomplish this exercise and we certainly appreciate their assistance.

If we can be of further assistance, please let us know.

Yours very truly,

P. W. Lashbrooke

Enclosure

cc: J. H. Guy
R. B. Warden
K. Zarker
A. M. Burns
Facilities Task Group

NATIONAL PETROLEUM COUNCIL REFINING STUDY

CAPITAL AND EXPENSE REQUIREMENTS FOR NEW FACILITIES

In an effort to assure comparable results from the several phases of this study, the contractors involved were asked to provide the numbers they were proposing to use for:

Geographic Location Differentials
Process Unit Investment Capital
Fixed Operating Expenses
Variable Operating Expenses
Offsite Investment Capital

and, some **Other One-Time Cost** have been defined for inclusion.

Evaluation of the numbers, as well as some arbitrary judgments, produced the attached tables.

It is recommended that the Geographic Location Differentials, Offsite Investment Capital and Other One-Time Cost factors be used by all study participants as presented. With regard to Process Unit Investment Capital, Fixed Operating Cost and Variable Operating Cost, it is recommended they be used for model tuning as required. However, knowing that spreadsheet and LP model modifications can be quite complex, each contractor is asked to closely review the factors and assumptions involved and make their own decision regarding changes. It is fully realized that all supporting assumptions may not be the same so if you are confident of your numbers, use them.

For facilities you will be estimating but which are not included in these list please exercise the same judgment factors. That is, if you detected a trend in your other numbers and made a correction, continue to do so.

For questions please contact:

Joe Marcinek	Phone:	703-846-4753
	FAX:	703-846-4742
John Gray	Phone:	606-329-5902
	FAX:	606-329-5999

\npcic0
03/11/92

NATIONAL PETROLEUM COUNCIL REFINING STUDY

GEOGRAPHIC LOCATION COST DIFFERENTIALS

LOCATION	FACTOR
U.S. Gulf Coast PAD III	1.0
U.S. East Coast PAD I	1.2
U.S. Midwest PAD II and IV	1.2
California (see note) PAD V	1.2
Middle East (Saudi Arabia)	1.2
Canada (Sarnia)	1.3
N.W. Europe (Great Britain)	1.3
Italy	1.1
Singapore / Taiwan	1.0
Venezuela	1.3

Note:

- Factors are applicable for the capital investment required to construct identical facilities at each location. Differing facility requirements should be reflected in base investments.
- The factor for California should be increased by 0.2 to reflect environmental, permitting and other complexity cost required there.

\npcic1
04/06/92

NATIONAL PETROLEUM COUNCIL REFINING STUDY

PROCESS UNITS INVESTMENT CAPITAL

PROCESS UNIT	CAPACITY, MBPSD	$ MILLION
Crude (w/o gas plant)	150	50
Vacuum	40	25
Delayed Coker (4 drums)	25	110
Distillate Hydrotreater - 800psig	30	25
Reformer (CCR) - 100 psig	35	50
FCC and Gas Plant	70	150
FCC Feed Hydrotreater-1000psig	35	40
Hydrocracker - 2000 psig/2 stg	30	110
Alkylation (Sulfuric)	19	55
MTBE	2	10
Isomerization (C5-C6)	15	25
Hydrogen Plant - MMSCFD	60	50
SRU, TG, Amine - LTPD	200	20

Note:

- Texas Gulf Coast Open Shop Construction
- Mid 1991 dollars
- Basis for Alkylation, MTBE and Isomerization is barrels of product

Example:

30 MBPSD East Coast Hydrocracker

Base cost + Location + Offsite + Other

$110 Million x (1.2 + 0.45 + 0.2) =

$204 Million (plus catalyst)

\npcic2
04/06/92

NATIONAL PETROLEUM COUNCIL REFINING STUDY

FIXED OPERATING EXPENSES

PROCESS UNIT	CAPACITY, MBPSD	$ / BPSD
Crude (w/o gas plant)	150	0.08
Vacuum	40	0.13
Delayed Coker (4 drums)	25	1.20
Distillate Hydrotreater - 800psig	30	0.23
Reformer (CCR) - 100 psig	35	0.36
FCC and Gas Plant	70	0.55
FCC Feed Hydrotreater-1000psig	35	0.28
Hydrocracker - 2000 psig/2 stg	30	0.92
Alkylation (Sulfuric)	19	0.76
MTBE	2	1.20
Isomerization (C5-C6)	15	0.30
Hydrogen Plant - MMSCFD	60	0.19
SRU, TG, Amine - LTPD	200	30.0

Note:

- Includes maintenance, taxes, insurance and offsite allocation
- Does not include any capital charge
- Hydrogen is $ / MSCF
- SRU is $ / LT

\npcic3
03/11/92

NATIONAL PETROLEUM COUNCIL REFINING STUDY

VARIABLE OPERATING EXPENSES

PROCESS UNIT	CAPACITY, MBPSD	$ / BARREL
Crude (w/o gas plant)	150	0.15
Vacuum	40	0.11
Delayed Coker (4 drums)	25	0.55
Distillate Hydrotreater - 800psig	30	0.26
Reformer (CCR) - 100 psig	35	1.12
FCC and Gas Plant	70	0.92
FCC Feed Hydrotreater-1000psig	35	0.39
Hydrocracker - 2000 psig/2 stg	30	1.20
Alkylation (Sulfuric)	19	2.00
MTBE	2	1.20
Isomerization (C5-C6)	15	0.83
Hydrogen Plant - MMSCFD	60	0.91
SRU, TG, Amine - LTPD	200	59.0

Note:

- Fuel is gas at $2.20 per MSCF
- MTBE cost assumes FCC gas as feed and full product fractionation and does not include MeOH
- Hydrogen is $ / MSCF
- SRU is $ / LT

\npcic4
04/06/92

NATIONAL PETROLEUM COUNCIL REFINING STUDY

OFFSITE INVESTMENT CAPITAL

- Total investment should be increased by 45% of the Process ISBL Capital to provide for required investments in offsites.

OTHER ONE-TIME COST

- Total investment should be increased by 20% of the Process ISBL Capital to provide for:

  - Site Preperation
  - Taxes
  - Start-up Cost
  - Owners Cost (permits, misc. engineering, etc.)
  - Other "On-Site" not anticipated

- First load catalyst cost should be included as Process Unit Investment Capital where applicable.

Bechtel

3000 Post Oak Boulevard
Houston, Texas 77056-6503
Mailing address: P.O. Box 2166
Houston, Texas 77252-2166

June 25, 1992

Conoco Incorporated
P. O. Box 2197
Houston, TX 77252

Attention: Mr. R. C. Bruce, TA3040

Subject: **NPC Study - 50,000 Barrel Light Product Tank**

Dear Ron:

As per your recent request Bechtel has developed the capital investment for a 50,000 barrel (working capacity) tank that could be storing a light hydrocarbon like motor gasoline. The tank investment is based on a double bottom, double seals on an external floater and a dome cover. A budgetary quote for the tank was received from CBI and included the dome cost from Ultraflote Corp. Other items included in the estimated investment are (1) concrete tank pad, (2) membrane lining of the dike area, (3) two transfer pumps, (4) instrumentation, (5) site improvements (6) electrical and (7) painting. No pilling costs are included.

The estimated investment is:

Item	$Million
Direct Field Costs	$1.350
Field Management	0.150
Subtotal Field	$1.500
Home Office and Engineering	0.225
Contingency	0.275
Total Investment	$2.000

Location: U.S. Gulf Coast
Time: Mid-1990

If you have any questions, please contact me.

Sincerely,

Ed. Swain

E. J. Swain

EJS:tr

cc: D. Lee

Bechtel

3000 Post Oak Boulevard
Houston, Texas 77056-6503
Mailing address: P.O. Box 2166
Houston, Texas 77252-2166

June 25, 1992

Mr. R. G. Bruce
Conoco Inc.
P.O. Box 2197
Houston, TX 77252

Subject: NPC Study - 20,000 BPSD MTBE Offshore Green Field Plant

Dear Ron:

As per your recent request Bechtel has developed capital investment and annual operating costs for a stand alone 20,000 BPSD MTBE green field plant sited in Saudi Arabia and Venezuela. The resulting estimated capital investment and annual operating and maintenance (O&M) expenses are as follows:

Item	Saudi Arabia	Venezuela
Capital Investment, $million	$343	$372
Operating & Maintenance, $MM/yr.	34.11	29.90
Operating & Maintenance, cents/gal.	12.31	10.79

Tables 1 and 2 summarize the capital investment and O&M expenses, respectively. If one wants to compare the cost of purchasing MTBE for a U.S. Refinery, the production cost of MTBE in Saudi Arabia would equal Bechtel's estimate of 12.31 cents/gal. plus the following costs:

- Butane and methanol costs
- By-product credit
- Local property tax and insurance
- Cost of capital
- Ocean freight

MTBE from Venezuela would be computed in a similar manner.

Also included are the bases and assumptions used for estimating the capital investment for the MTBE complex, Table 3.

We trust this note meets your current needs on this matter. If you have any questions, please contact me.

Sincerely

E. J. Swain

EJS:kae

cc: D. Lee
R. Ragsdale

TABLE 1

ESTIMATED CAPITAL INVESTMENT

Mid 1990 Basis
Million U. S. Dollars

	USGC Basis	Saudi Arabia	Venezuela
Onsite units (1)	$160		
Offsites	112		
Total Plant	$272		
Catalysts & Chemicals	6		
Royalties	8		
Total USGC	$286		
Saudi location		$343	
Venezuela location			$372

(1) Butane isomerization, isobutane dehydrogenation, and MTBE units.

TABLE 2

ESTIMATED

Operating & Maintenance Costs

Item	Saudi	Venezuela
	US$MM/Yr.	
Utilities	$5.00	$10.00
Catalysts & Chemicals	6.42	5.84
Maintenance M & L	10.29	11.16
Operating & Office Labor	12.40	2.90
Total O & M Cost	$34.11	$29.90
Cents/gallon (1)	12.31	10.79
Assumed Staffing:		
No. of personnel		
Manual	146	90
Non-manual	217	160

(1) Assume 330 operating days per year

TABLE 3

CAPITAL COST ESTIMATE

Basis and Assumptions

Basis and Assumptions:

- Plant capacity is 20,000 BPSD MTBE
- Cost basis is mid 1990 US dollars
- To be built on "Greenfield" site adjacent to existing industrial area
- Includes initial fill of catalysts and chemicals
- Includes a one-time Royalty payment
- Water, fuel, and electrical power is available at plant fence
- The Saudi and Venezuela costs include a camp, catering and ocean freight.

Exclusions:

- Mobile equipment, office equipment and furniture, phones, for permanent facilities
- Owners costs: Cost of land, Start-up, Operator training
- Working Capital: Cost of inventory, difference between accounts receivable and accounts payable
- Local and state taxes, import duties or fees
- Townsite or other permanent facilities for permanent staff or operators
- Building licenses and permits
- Interest during construction
- Builders risk insurance.

ATTACHMENT VII-4

Bechtel

3000 Post Oak Boulevard
Houston, Texas 77056-6503
Mailing address: P.O. Box 2166
Houston, Texas 77252-2166

August 25, 1992

Mr. R. G. Bruce
Director, Business Development
Refining and Research and Engineering
Conoco, Inc.
P. O. Box 2197
Room TA 3040
Houston, TX 77252

Subject: Offshore Refinery

Dear Mr. Bruce:

You recently requested if Bechtel could provide, as guidance, the capital investment for a green field offshore refinery. The Bechtel San Francisco office recently completed a study for a green field refinery in the Pacific Rim region. The refinery is rated at 150,000 BPSD crude distillation capacity and is considered a high conversion refinery. The capital cost is summarized as:

Item	U.S. $ Million (2nd Qtr. 1992)
Process Units	$ 968
Utilities & Offsites	591
Cat., Chem. & Royalty	41
Subtotal	$ 1,600
Design Allowance	240
Total Installed Cost	$ 1,840
Owner's Cost	100
Total Project, excluding Working Capital	$ 1,940

I hope this information helps in the overall NPC Study.

Sincerely,

E. J. Swain

E. J. Swain

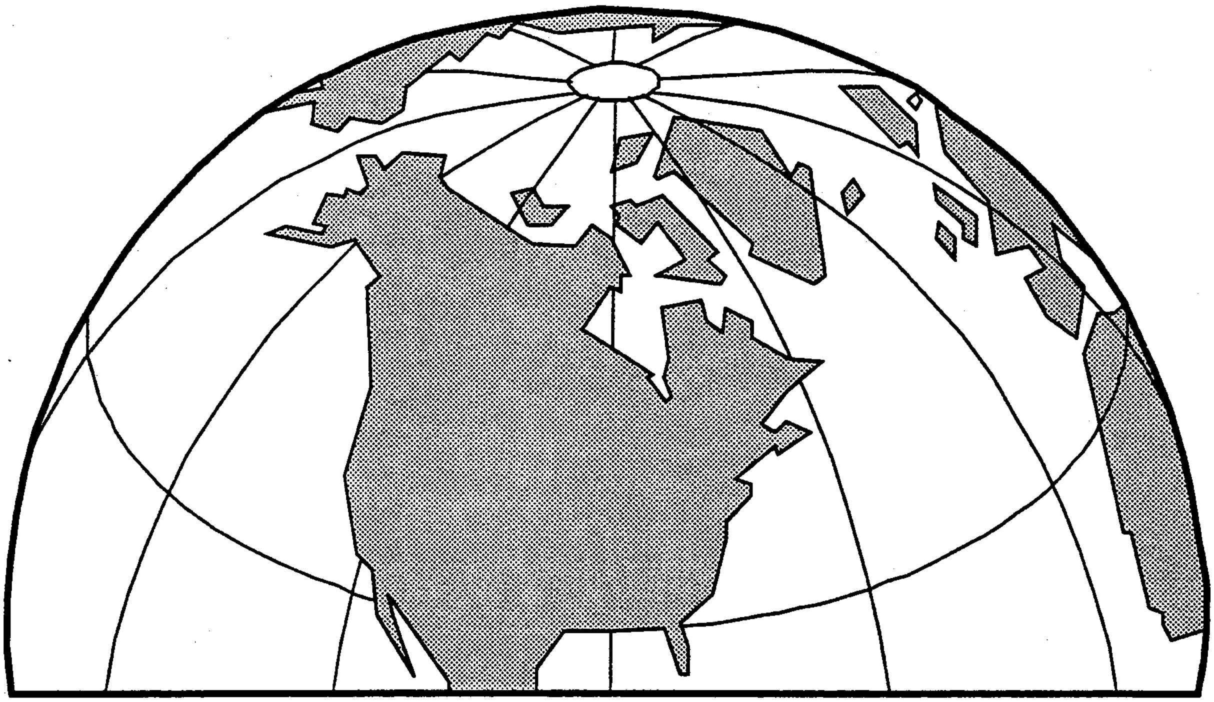
EJS:emg

Bechtel Corporation

SECTION II

BECHTEL REPORT

NATIONAL PETROLEUM COUNCIL



NPC ENVIRONMENTAL STUDY

IMPACTS OF ENVIRONMENTAL REGULATIONS ON U.S. PETROLEUM REFINERIES 1991 - 2010

Revision 3

Houston, Texas
August 25, 1993

Bechtel

3000 Post Oak Boulevard
Houston, Texas 77056-6503
Mailing address: P.O. Box 2166
Houston, Texas 77252-2166

August 25, 1993

Mr. H. F. Elkin
Senior Environmental Consultant
Sun Company, Inc.
1801 Market
Philadelphia, PA 19103

Subject: **Bechtel's NPC Environmental Methodology Cost Report - Revision 3**

Dear Mr. Elkin:

As requested by the National Petroleum Council (NPC), the following deliverable report contains Bechtel's methodology and findings on the investment impact of environmental and safety and health regulations on the U.S. petroleum refining industry. This report complements Bechtel's Cost Report released to NPC on September 1, 1992. Both Bechtel Reports will assist NPC in studying the economic impact of current and potential environmental and safety and health regulations on the U.S. petroleum refining-marketing industries.

These findings were also shared with the NPC Refinery Facilities Task Group at the NPC-Bechtel Progress Review Meetings held during the past year of 1992. Bechtel's focus was on developing control systems and programs to meet NPC's premises on those regulations affecting U.S. refinery operations (excluding clean fuels). Based on NPC's implementation schedules, Bechtel also estimated the investment and O&M expenses for the control systems and programs.

The Bechtel investment values and O&M expenses are based on mid-1990 U.S. Gulf Coast rates. NPC will utilize and adjust Bechtel's values under its assumptions for refineries sited throughout the U.S. As opted, NPC will utilize its survey data for the 1991 through 1995 time frame. It is assumed the survey data includes all refinery environmental expenditures for the 1991 through 1995 period – more than those covered under the NPC premises.

As requested by NPC, Bechtel prepared a brief description of how the Capital Investment Values and O&M Expenses developed by Bechtel were modified to arrive at the values reported in the NPC Report. The description of the transformation of values are presented in the Preface of this Revision 3 Report rather than in the Executive Summary of Revision 2 Report.

After a further review of Revision 3 Report is made by the NPC Refinery Facilities Task Group, if any additional modifications or additions are required, please contact me.

Sincerely,

E. J. Swain

E.J. Swain

cc: J. H. Guy, IV-NPC
Bechtel NPC Study Team

Bechtel Corporation

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

LIST OF TABLES

Tables **Page**

LIST OF TABLES

LIST OF TABLES

LIST OF FIGURES

LIST OF FIGURES

PREFACE

PREFACE

NPC Environmental Expenditure Values

Bechtel's part of the overall NPC Study was to determine the environmental control systems and programs that would be required by the U.S. refineries to meet the NPC's environmental premises for stationary sources. Bechtel and the NPC jointly defined the environmental control systems and programs and Bechtel then estimated the capital expenditures, one-time costs and operating and maintenance (O&M) expenses of the required facilities and programs.

The estimated capital investments values were based on mid-1990 U.S. Gulf Coast construction rates. One-time expenses were developed utilizing mid-1990 U.S. Gulf Coast conditions. The O&M expenses were developed utilizing mid-1990 U.S. Gulf Coast unit costs for labor, utilities, and chemicals. Maintenance expenses were estimated as a percentage of capital investment or as applicable to stand-alone programs.

NPC defined the time periods in which the control systems and programs may be implemented. The three periods are:

- 1991 through 1995
- 1996 through 2000
- 2001 through 2010

NPC premises do not cover all environmental expenditures that the U.S. refining industry will be incurring for the 1991 through 1995 period. However, the NPC premises do provide continuity for the methodology Bechtel employed to develop investments and costs for the two other time periods: 1996 through 2000 and 2001 through 2010. Although Bechtel developed investment and cost values for the NPC premises for the 1991 through 1995 period, the NPC elected to base their work on survey response data in that period. The survey information includes all refinery environmental expenditures for the 1991 through 1995 period. The resulting capital expenditures and one-time costs utilizing the adjusted NPC survey data for the 1991-1995 time period is shown in Table P-1.

TABLE P-1
CAPITAL EXPENDITURES AND ONE-TIME
COSTS TO MEET CURRENT ENVIRONMENTAL REGULATIONS
($ BILLION)

Environmental Sector	Capital	One-Time	Total
Air	6.80	1.10	7.90
Wastewater	3.02	0.81	3.83
Hazardous and Non-hazardous Solid Wastes	1.28	1.89	3.17
Safety and Health	1.50	0.70	2.20
Total	12.60	4.50	17.10

Note: Mid-1990 Dollars

The resulting O&M expenses utilizing the adjusted NPC survey data for the 1991-1995 time period is shown in Table P-2.

TABLE P-2
O&M EXPENSES REQUIRED
TO MEET CURRENT ENVIRONMENTAL REGULATIONS
($ BILLION PER YEAR)

Environmental Sector	1995
Air	1.90
Wastewater	0.86
Hazardous & Non-Hazardous Solid Wastes	0.74
Safety and Health	0.24
Total	3.75

Note: Mid-1990 Dollars

Bechtel developed the environmental expenditures based on using U.S. Gulf Coast conditions such as construction rates, operating labor, utilities and chemicals. As the 187 refineries are located in 37 states NPC adjusted the expenditures to reflect the site locations of the refineries. Assigning a base factor of 1.0 to the U.S. Gulf Coast, NPC developed the following geographic adjustment factors to be applied against environmental capital expenditures during the 1996 - 2000 and 2001 - 2010 time periods.

Geographic Location	Adjustment Factor
U.S. Gulf Coast (open shop)	1.0
California	1.4
Balance of U.S. (ex. California)	1.2

Adjustments for the one-time costs during the 1996 - 2000 and 2001 - 2010 time periods are similar to those used on capital expenditures. However, a California escalation factor of 1.1 was assigned to reflect added ongoing burden as judged by NPC.

The O&M expenses related to capital expenditures that may be incurring during the 1996 - 2000 and 2001 - 2010 time periods were adjusted using the same site location factors as used to adjust capital.

The NPC portion of Tables P-3, P-4, and P-5 reflect both the use of location factors and utilization of survey information for the period 1991 - 1995. The estimated capital expenditures was adjusted from $27.80 billion to $36.30 billion over a 20 year period and the estimated one-time costs from $3.16 billion to $6.98 billion. The largest adjustment of capital expenditures plus one-time costs will be occurring during the 1991 - 1995 time period going from $7.77 billion to $17.10 billion and O&M expenses will change from $0.39 billion per year (1995) to $3.75 billion per year (1995).

The NPC environmental expenditures during the 1991 - 2010 time period reflects the impact of existing and anticipated regulations related to air, wastewater, solid wastes, and safety and health facing the U.S. refineries.

TABLE P-3
CAPITAL EXPENDITURES AND ONE-TIME COST FACING THE U.S. REFINING INDUSTRY, 1991 - 2010
($ BILLION)

Bechtel Values

Environmental Sector	Capital	One-Time	Total
Air	7.50	0.04	7.54
Wastewater	12.33	0.01	12.34
Hazardous and Non-hazardous Solid Wastes	3.67	2.15	5.82
Safety and Health	4.30	0.96	5.26
Total	27.80	3.16	30.96

Note: Costs are expressed in mid-1990 U. S. Gulf Coast dollars.

NPC Values

Environmental Sector	Capital	One-Time	Total
Air	11.30	1.13	12.43
Wastewater	15.65	0.82	16.47
Hazardous and Non-hazardous Solid Wastes	4.95	4.08	9.03
Safety and Health	4.40	0.95	5.35
Total	36.30	6.98	43.28

Note: Costs are expressed in mid-1990 dollars and are site adjusted.

TABLE P-4
CAPITAL EXPENDITURES AND ONE-TIME COST FACING THE U.S. REFINING INDUSTRY BY TIME FRAME
($ BILLION)

Bechtel Values

Environmental Sector	1991-1995	1996-2000	2001-2010	Total
Air	3.55	1.90	2.09	7.54
Wastewater	1.25	4.48	6.61	12.34
Hazardous and Non-hazardous Solid Wastes	0.46	2.36	3.00	5.82
Safety and Health	2.51	1.42	1.33	5.26
Total	7.77	10.16	13.03	30.96

Note: Costs are expressed in mid-1990 U. S. Gulf Coast dollars.

NPC Values

Environmental Sector	1991-1995	1996-2000	2001-2010	Total
Air	7.90	2.13	2.40	12.43
Wastewater	3.83	5.12	7.52	16.47
Hazardous and Non-hazardous Solid Wastes	3.17	2.58	3.28	9.03
Safety and Health	2.20	1.65	1.50	5.35
Total	17.10	11.48	14.70	43.28

Note: Costs are expressed in mid-1990 dollars and are site adjusted.

TABLE P-5
ENVIRONMENTAL O&M EXPENSES
FACING THE U.S. REFINING INDUSTRY
($ BILLION)

Bechtel Values

Environmental Sector	1995	2000	2010
Air	0.23	0.45	0.15
Wastewater	0.04	0.41	0.57
Hazardous and Non-hazardous Solid Wastes	0.06	1.14	0.10
Safety and Health	0.06	0.18	0.18
Total	0.39	2.15	1.00

Note: Costs are expressed in mid-1990 U. S. Gulf Coast dollars.

NPC Values

Environmental Sector	1995	2000	2010
Air	1.90	0.50	0.15
Wastewater	0.86	0.42	0.68
Hazardous and Non-hazardous Solid Wastes	0.74	1.18	0.12
Safety and Health	0.25	0.20	0.20
Total	3.75	2.30	1.15

Note: Costs are expressed in mid-1990 dollars and are site adjusted.

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

The U.S. petroleum refining Industry will incur major costs to meet current and future environmental, safety, and health regulations. Estimated compliance costs of about $31 billion face U.S. refiners for operating refineries in an environmental clean mode during 1991 through 2010.

The $31 billion is divided among four sectors: air, wastewater, hazardous and nonhazardous solid wastes, and safety and health. The $31 billion capital expenditures by the four sectors is presented in Table ES-1.

Table ES-1
CAPITAL EXPENDITURES AND ONE-TIME COSTS FACING THE U.S. REFINING INDUSTRY
($ BILLION)

Environmental Sector	Capital	One-Time	Total
Air	7.50	0.04	7.54
Wastewater	12.33	<0.01	12.34
Hazardous and Nonhazardous Solid Wastes	3.67	2.15	5.82
Safety and Health	4.30	0.96	5.26
Total	27.80	3.16	30.96

Note: Costs are expressed in mid-1990 U.S. Gulf Coast dollars.

The estimated capital expenditures are for environmental control systems and programs to meet NPC premises. These premises incorporate many of the current and future federal environmental, safety, and health regulations and are listed in each sector.

The estimated capital requirements for the wastewater sector accounts for about 40 percent of the total expenditures. In the last few years, capital expenditures in the air sector have dominated spending by U.S. refiners. Funding for the air sector is expected to drop off after the 1991 through 1995 period, whereas spending for the wastewater sector picks up significantly after 1996. The spending pattern of the $31 billion by time frame is presented in Table ES-2.

Table ES-2
CAPITAL INVESTMENT
AND ONE-TIME COSTS
BY TIME FRAME
($ BILLION)

Environmental Sector	1991-1995	1996-2000	2001-2010	Total
Air	3.55	1.90	2.09	7.54
Wastewater	1.25	4.48	6.61	12.34
Hazardous and Nonhazardous Solid Wastes	0.46	2.36	3.00	5.82
Safety and Health	2.51	1.42	1.33	5.26
Total	7.77	10.16	13.03	30.96

Operating and maintenance (O&M) expenses that the U.S. refineries will incur due to environmental control systems and programs are listed in Table ES-3.

Table ES-3
ENVIRONMENTAL O&M EXPENSES
($ BILLION PER YEAR)

Environmental Sector	1995	2000	2010
Air	0.23	0.45	0.15
Wastewater	0.04	0.41	0.57
Hazardous and Nonhazardous Solid Wastes	0.06	1.14	0.10
Safety and Health	0.06	0.18	0.18
Total	0.39	2.18	1.00

Extending the O&M expenses shown above could result in U.S. refiners incurring costs in the range of $41 - $45 billion between 1991 through 2010 period for operating environmental control systems and programs.

Air Sector

Refinery air emissions will be reduced during the late 1990s and in the first decade of the 21st century. Improvements in ambient air quality and reduction of toxic emissions will result from regulatory initiatives that target air emissions.

The estimated cost increments for the U.S. refining industry to meet the NPC's premises on air regulations are:

	$ Billion						
Item	**1991-1995**	**1995**	**1996-2000**	**2000**	**2001-2010**	**2010**	**Total**
Capital Investment	3.54	---	1.87	---	2.09	---	7.50
One-Time Costs	<0.01	---	0.03	---	---	---	0.04
Total	3.55	---	1.90	---	2.09	---	7.54
O&M Expenses	---	0.23	---	0.45	---	0.15	---

Note: Costs are expressed in mid-1990 U.S. Gulf Coast dollars.

The estimated capital expenditures and O&M expenses are based on the control technologies and programs premised by NPC. (Programs are environmental permit applications, emission fees, enhanced inspection expenses, etc.) These premises are based upon provisions in the CAAA and anticipated rules that the various states will promulgate to further improve air quality.

The controls will be phased-in mostly during the 1991 through 2000 time frame. The NPC air premises are summarized in Table 3-6 on pages 3-14, 3-15, and 3-16 and include the implementation schedule from 1991 through 2010.

The estimated capital investment of $7.50 billion will be spread over five types of emissions as indicated below:

Emission	$ Billion	Percent
VOC	3.76	50.1
PM-10	1.63	21.7
SO_2	0.96	12.9
NO_X	0.92	12.3
Toxics	0.23	3.0

The major areas in which investments will be made are VOC and PM-10. Although spending for SO_x reduction appears to be small, it is due to the maturity of medium-large refineries already have installed sulfur recovery units (SRUs) and sulfur tail gas recovery units.

Also, spending for NO_x reduction may appear to be low. NO_x reduction is being planned for the use of ultra-low NO_x burners rather than SCRs on large process heaters (over 100 million BTU/Hour) except in severe and extreme ozone nonattainment areas. Also insufficient information was available to determine NO_x control systems on refinery steam/power generation system.

The one-time costs of $0.04 billion are for two programs:

- Enhanced inspection and maintenance
- Switching to clean fuel, natural gas replacing No. 6 fuel oil as a refinery fuel

Several control systems and programs that contribute to a major share of the O&M expenses are:

- Switching to clean fuel, natural gas replacing No. 6 fuel oil as a refinery fuel
- Conducting enhanced inspection and maintenance programs
- Operating redundant and new SRUs and tail gas sulfur recovery units

Wastewater Sector

Refinery wastewater programs being implemented during the 1990s and in the first decade of the 21st century area are a product of EPA's Clean Water Act (CWA) Reauthorization of 1990.

The incremental cost estimates for the U.S. refining industry to meet the NPC's premises of CWA are:

	$ Billion						
Item	1991-1995	1995	1996-2000	2000	2001-2010	2010	Total
Capital Investment	1.25	---	4.48	---	6.60	---	12.33
One-Time Costs	---	---	---	---	<0.01	---	<0.01
Total	1.25	---	4.48	---	6.61	---	12.34
O&M Expenses	---	0.04	---	0.41	---	0.57	---

Note: Costs are expressed in mid-1990 U.S. Gulf Coast dollars.

The NPC's premises on which estimated wastewater control systems and programs are based have been developed from existing and anticipated wastewater regulations. NPC's premises are summarized in Table 4-1 on pages 4-2, 4-3, and 4-4 and include the implementation schedule from 1991 through 2010.

The estimated capital investment of $12.33 billion will be spread over three regulations as indicated below:

Item	$ Billion	Percent
CWA Reauthorization	7.59	61.5
Groundwater Issues	3.55	28.8
Storm Water Quality	1.19	9.7

The major area of wastewater investment will be made to reduce and control the toxicity of refinery wastewater effluent during the 1996 through 2010 time frame.

The one-time cost of only $8 million is for a program to remove sediment that has been discharged into a quiescent body of surface water such as a lake. The implementation schedule for this program incurs 25 percent in period 2001 through 2010, and 75 percent after 2010.

Two control systems and programs that contribute the major share of the O&M expenses are:

- Reduction of toxicity in wastewater effluents
- Maximum practical reuse of process wastewater

Hazardous and Nonhazardous Solid Waste Sector

Refinery hazardous and nonhazardous solid waste programs being implemented during the 1990s and in the first decade of the 21st century will result from a number of regulatory initiatives that target disposal of solid waste. The premises addressed under the broad category of solid and hazard waste utilized in this study are assigned into six subcategories:

- Groundwater Issues
- Above Ground Storage Tanks
- RCRA Reauthorization
- RCRA Toxicity Characteristic (TC) Land Disposal Restrictions (LDR)
- RCRA Corrective Action
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)

The incremental cost estimates for U.S. refineries to meet the NPC's premises of solid and hazardous waste regulations are:

	$ Billion						
Item	1991-1995	1995	1996-2000	2000	2001-2010	2010	Total
Capital Investment	0.46	---	1.29	---	1.92	---	3.67
One-Time Costs	<0.01	---	1.07	---	1.08	---	2.15
Total	0.46	---	2.36	---	3.00	---	5.82
O&M Expenses	---	0.06	---	1.14	---	0.10	---

Note: Costs are expressed in mid-1990 U.S. Gulf Coast dollars.

The estimated capital expenditures and O&M expenses are based on the control technologies and programs premised by NPC. These premises are based upon provisions in the RCRA and CERCLA regulations and anticipated rules that the various states will promulgate to further improve the disposition of hazardous and nonhazardous solid wastes. These premises are summarized in Table 5-1 on pages 5-4, 5-5, and 5-6 and include the implementation schedule from 1991 through 2010.

The estimated capital investment of $3.67 billion will be spread over three areas:

Item	$ Billion	Percent
Aboveground Tanks	1.90	51.6
Other RCRA Issues	1.39	37.9
Groundwater Issues	0.38	10.5

The major areas of investment will be in the replacement of aboveground storage tankage (both light and heavy hydrocarbon service) and for RCRA corrective action on inactive hazardous SWMUs.

The estimated incremental one-time cost of $2.15 billion is for one major program - remediation of contaminated soil.

The program that contributes a major share to the O&M expenses is RCRA reauthorization - new listings. Disposal of five waste materials (non-leaded tank bottoms, spent fluid cracking catalyst, liquid waste amine streams, sulfur, and spent caustic) that are produced during normal refinery operations creates major cost for refineries.

Safety and Health Sector

New refinery safety and health programs being implemented during the 1990s and in the first decade of the 21st century will be a product of Occupational Safety and Health Administration's (OSHA) "Process Safety Management" legislation as described in 29 CFR 1920.119 and the proposed regulations as required by the CAAA of 1990.

The incremental cost estimates for the U.S. refining industry to meet the NPC's premises on safety and health are:

	$ Billion						
Item	**1991-1995**	**1995**	**1996-2000**	**2000**	**2001-2010**	**2010**	**Total**
Capital Investment	1.78	---	1.27	---	1.25	---	4.30
One-Time Costs	0.73	---	0.15	---	0.08	---	0.96
Total	2.51	---	1.42	---	1.33	---	5.26
O&M Expenses	---	0.06	---	0.18	---	0.18	---

Note: Costs are expressed in mid-1990 U.S. Gulf Coast dollars.

The estimated capital expenditures and O&M expenses are based on the control technologies and programs premises by NPC. The premises reflect NPC and the petroleum industry perceptions of the potential EPA regulations for process safety and health. The NPC's premises are summarized in Table 6-1 on pages 6-2 and 6-3 and includes the implementation schedule from 1991 through 2010.

The estimated capital investment of $4.30 billion will be spread over three areas:

Item	$ Billion	Percent
Phase-out Hazardous Materials (HF)	2.46	57.0
Process Safety Management (PSM) Programs	1.47	34.3
Others	0.37	8.7

The major area of process safety and health investment during the 1991 through 1995 time frame will be made on PSM programs. The phase-out of hazardous materials-replacement of HF acid alkylation units with H_2SO_4 acid alkylation units - may occur in the 1996 through 2010 time frame. The investment for the replacement of the HF acid alkylation units account for the major portion of the investment during the two time periods of 1996 through 2000 and 2001 through 2010.

The estimated one-time costs of $0.96 billion will be spread over four areas:

Item	$ Billion	Percent
PSM Programs and Training	0.34	35.8
Phase-out Hazardous Materials (HF)	0.16	16.7
Controlling Worker Exposure	0.16	16.7
Others	0.30	30.8

The one-time costs are rather small for a refinery but they cover a number of programs.

The O&M expenses during the 1991 through 1995 time frame are for six programs. In the 1996 through 2010 period, the O&M expense is for H_2SO_4 acid alkylation units that have replaced HF acid alkylation units.

Major Compliance Costs

In analyzing the environmental regulations that contribute to the estimated compliance costs of $27.80 billion, ten regulations and their associated costs of $23.31 billion accounts for about 84 percent of the total costs. The major compliance costs are listed in Table ES-4.

The regulation with the highest compliance cost covers the need to reduce the toxicity of refinery wastewater. An estimated cost of $6.59 billion will be required to implement projects to achieve the program of reducing the toxicity of refinery wastewater.

Regulations affecting refinery above ground storage tanks is the next largest compliance cost at an estimated investment of $4.54 billion. The $4.54 billion compliance costs for storage tanks fall into three sectors: (1) Air Sector-VOC at $0.59 billion, (2) Wastewater Sector-Groundwater at $2.05 billion, and (3) Hazardous and Nonhazardous Solid Wastes Sector-Storage Tanks at $1.90 billion. Storage tanks are a good example of a refinery facility affected by several regulations which can compound its total compliance costs.

The estimated one-time cost of $2.15 billion to remediate contaminated soil accounts for 68 percent of the total one-time costs of $3.16 billion. The estimated quantity of contaminated soil was derived from NPC Survey data. However, the degree of contamination for the reported quantity of soil is unknown. The program priced to handle the contaminated soil is closure in place (capping) and applies to the total 187 refineries. Other options to handle the contaminated soil leads to higher costs. These option cases are covered under sensitivity analysis discussions.

Table ES-4

MAJOR COMPLIANCE COSTS
(1991 THROUGH 2010)

Sector/Item	Capital Investment ($ Billion)	One-Time Costs ($ Billion)	O&M Expenses ($ Billion Per Year)
Air			
VOC	3.76		
PM-10	1.63		
SO_2	0.97		
Wastewater			
CWA Reauthorization			
Reduce Toxicity	6.59		
Storm Water	1.20		
Groundwater			
Storage Tanks	2.05		
Hazardous and Nonhazardous Solid Wastes			
Storage Tanks	1.90		
SWMUs-Inactive Hazardous	1.27		
Remediate Contaminated Soil		2.15	
New Listing			1.01
Safety and Health			
HF Alkylation Replacement	2.46		
PSM Program	1.48		
Total	23.31		

A major O&M expense of $ 1.01 billion per year is for the disposal of five waste materials that are produced during normal refinery operations. The five waste materials are:

- Non-leaded tank bottoms
- Spent fluid cracking catalyst
- Liquid waste amine streams
- Sulfur
- Spent Caustic

The large yearly O&M expense for disposal of these five waste materials could be an incentive for refiners to develop operational procedures or processes to reduce the production of these five waste materials.

Environmental Compliance Costs Versus Refinery Capacity

"Are there benefits from economies of scale in the refining industry when considering environmental compliance costs?" In an attempt to determine if there are any benefits from economies of scale, the 187 refineries comprising the U.S. refining industry as of January 1, 1990, were assigned into nine groups based on crude distillation capacity. The distribution of the 187 refineries into the mine groups are:

Group	Crude Capacity, kBPSD	Number of Refineries	Average Capacity, kBPSD
a	1.0 - 10.0	26	6.8
b	10.0 - 25.0	24	16.6
c	25.0 - 50.0	40	38.7
d	50.0 - 75.0	28	61.8
e	75.0 - 100.0	12	88.2
f	100.0 - 150.0	24	126.0
g	150.0 - 200.0	11	173.7
h	200.0 - 300.0	14	253.2
i	300.0 Plus	8	376.3

Process configuration, supporting offsite facilities, land, and manpower requirements, etc., can be averaged for each of the nine groups. This enables the environmental control systems and programs to be better defined for refineries in each group. NPC Survey data was sorted into the nine refining groups and provided guidance to develop the number and capacities of environmental control systems and programs for each group.

The capital investment for environmental control systems and programs for the four sectors were developed for refineries in each of the nine groupings. The capital investment for each of the nine groupings are shown for the three time periods in Table ES-5. Between 1991 and 2010, a refiner in Group a will have to invest $28 million to be in compliance. A refiner in Group i to be in compliance would have to invest $500 million in the same 20-year period.

The compliance costs per refinery by refinery group by the three time periods are shown in Figure ES-1. The data illustrates that yearly capital requirements are evenly distributed throughout the twenty-year period.

The one-time compliance costs per refinery by refinery group are presented in Table ES-6. Although the one-time compliance costs appear to be minor, they could occur over a one or two-year period. This could create a cash flow problem for some refiners.

When the compliance costs (capital plus one-time) per refiner per refinery group is expressed as dollar per barrel, the economy of scale appears to exist. The dollar per barrel data is presented in Table ES-7 and is illustrated in Figure ES-2. The small refiner in Group a will be incurring a compliance cost of about $4,400 per barrel, whereas a refiner in Group i will incur a compliance cost of about $1,400 per barrel. A Group a refiner will need to spend $30 million over 20 years to be in compliance. However, his product margin may not generate sufficient funds to cover compliance costs. This same funding problem could also affect Groups b and c refiners.

The estimated compliance costs are based on mid-1990 Gulf Coast rates. When NPC location factors are used, the following dollar per barrel compliance costs are developed:

	Dollar Per Barrel	
Group	Gulf Coast Costs (1)	Location Adj. (2)
a	4,385	5,135
b	2,625	3,070
c	2,385	2,805
d	2,190	2,565
e	1,990	2,315
f	2,115	2,515
g	1,730	1,980
h	1,615	1,825
i	1,380	1,415

(1) Capital Investment and one-time costs based on mid-1990 U.S. Gulf Coast.
(2) Capital Investment and one-time costs based on mid-1990 and adjusted for refineries located in No. 3PADD, California, and all other states.

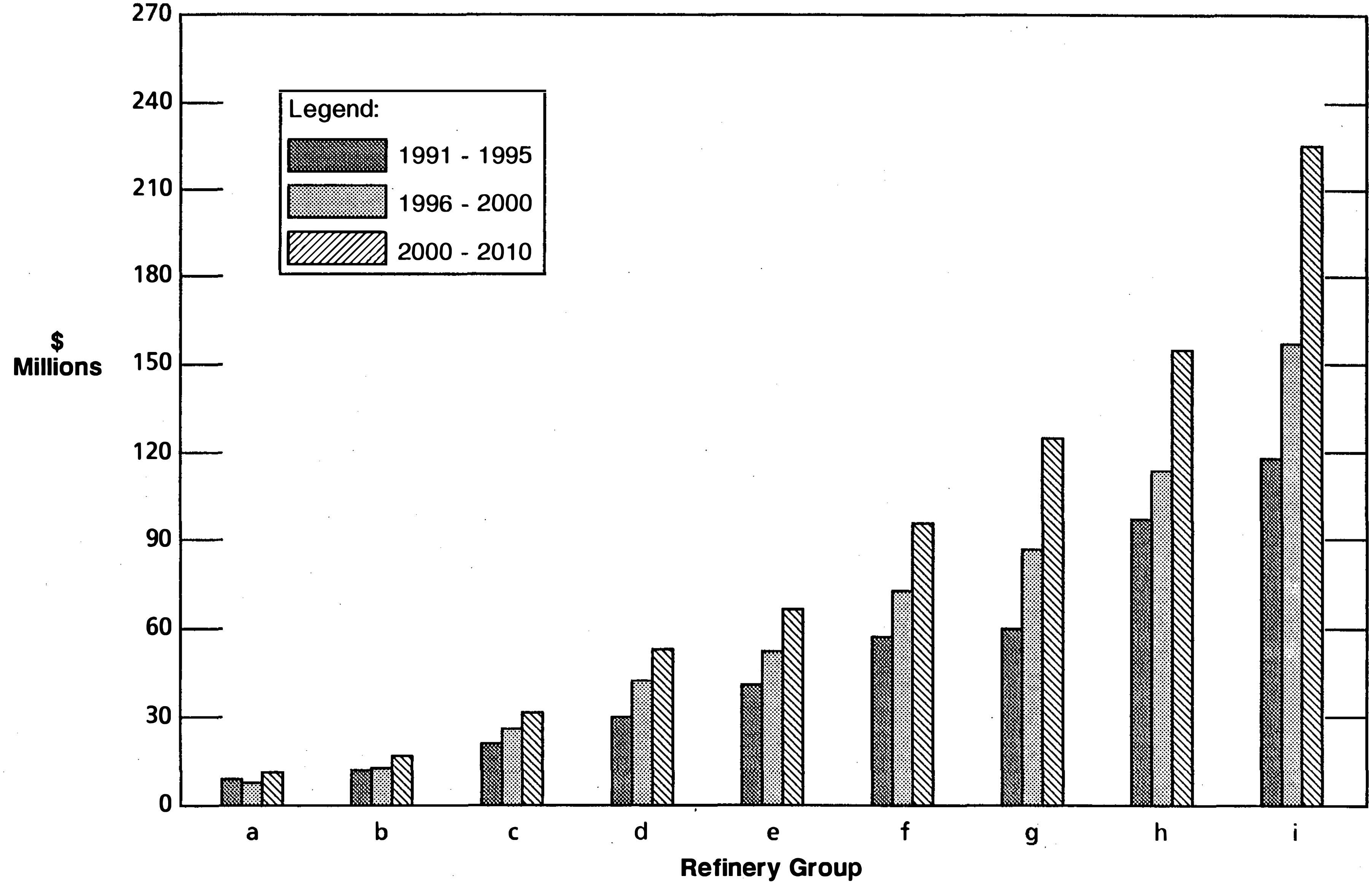
Table ES-5

SUMMARY OF CAPITAL INVESTMENT COMPLIANCE COSTS
($ MILLION)

Group	No. of Refineries Per Group	Capital Investment Per Group	Capital Investment Per Refinery 1991 - 1995	1996 - 2000	2001 - 2010	Total
a	26	738	9	8	11	28
b	24	995	12	13	17	42
c	40	3,123	21	26	32	79
d	28	3,513	30	42	53	125
e	12	1,923	41	53	66	160
f	24	5,411	57	73	95	225
g	11	2,995	60	87	125	272
h	14	5,115	97	114	154	365
i	8	4,000	118	157	225	500
Total	187	27,813	--	--	--	--

Figure ES-1

CAPITAL INVESTMENT PER REFINERY FOR FOUR CONTROL TECHNOLOGIES BY REFINERY GROUP AND TIME PERIODS



1092001-2

Table ES-6

SUMMARY OF ONE-TIME COMPLIANCE COSTS
($ MILLION)

Group	No. of Refineries Per Group	One-Time Costs Per Group	One-Time Costs Per Refinery 1991 - 1995	1996 - 2000	2001 - 2010	Total
a	26	36	<1	<1	<1	2
b	24	495	<1	<1	<1	2
c	40	568	2	6	5	13
d	28	278	3	4	3	10
e	12	183	4	6	6	16
f	24	980	6	18	17	41
g	11	311	8	11	10	29
h	14	603	11	16	16	43
i	8	151	12	4	8	19
Total	187	3,605	--	--	--	--

Table ES-7

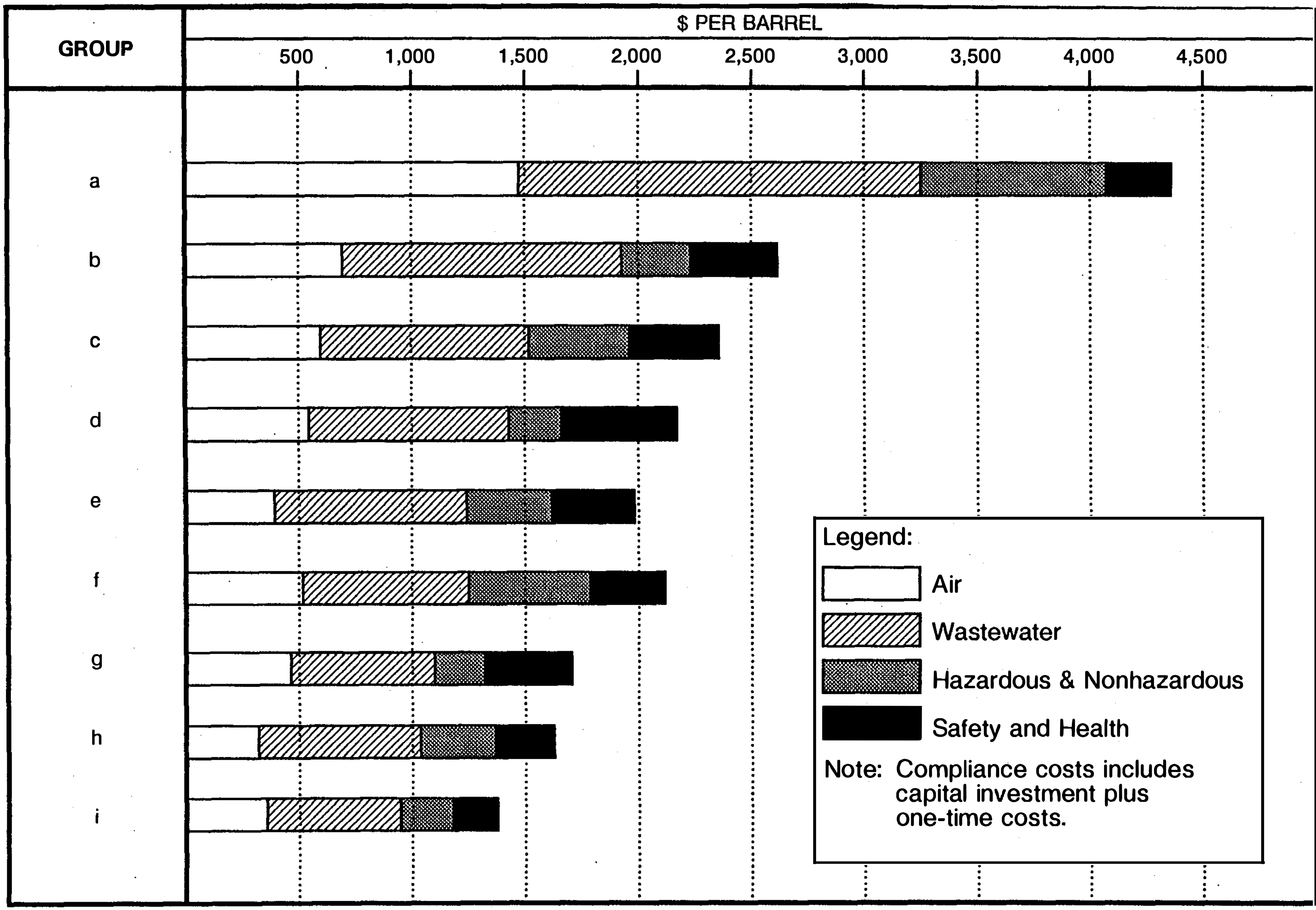
SUMMARY OF DOLLAR PER BARREL COMPLIANCE COSTS BY REFINERY GROUPS

			Per Refinery					
				$ Per Barrel				
Group	No. of Refineries Per Group	Average Crude Capacity, kBPSD	Total Capital $ Million	Air Sector	Wastewater Sector	Hazardous and Nonhazardous Sector	Safety and Health Sector	Total
a	26	6.8	30	1,495	1,765	830	295	4,385
b	24	16.6	44	730	1,205	295	395	2,625
c	40	38.7	92	600	905	465	415	2,385
d	28	61.8	135	550	885	245	510	2,190
e	12	88.2	176	410	840	360	380	1,990
f	24	126.0	266	505	745	550	315	2,115
g	11	173.7	301	455	655	230	390	1,730
h	14	253.2	408	325	700	345	245	1,615
i	8	376.3	519	370	580	240	190	1,380
Total	187							

Note: Total Capital Investment Equals Capital Investment Plus One-Time Costs

Figure ES-2

DOLLARS PER BARREL COMPLIANCE COSTS BY REFINERY GROUPS PER REFINERY



1092001-2

The economies of scale become even more predominant when location factors are considered. Group a, b and c refineries would require greater product margins to cover even the larger compliance costs. This could cause funding problems for some of the small refineries. In the worst case scenario, they may be forced to close their operations.

Sensitivity Analysis

At the direction of NPC, the following nine sensitivity analyses were evaluated for the cost impacts of possible changes and/or modifications in air and hazardous and nonhazardous solid wastes regulations. Each of the nine sensitivity cases could have a major capital impact on the U.S. refining industry that would range from $0.51 billion to $85.12 billion.

NPC considered five regulations of having some likelihood of being imposed. The estimated capital investment and one-time costs for these potential regulations are presented in Table ES-8.

- VOC from PRVs on large columns and fractionators, $0.72 billion. As indicated from responses on the NPC Survey, refineries in Groups f, h, and i would incur major investment to install new relief header and flare systems for collecting VOC from PRVs, crude column vents, and main fractionator vents on down stream processing units.

- Retrofit surface improvements and landfill contaminated soil, $2.67 billion. The NPC survey indicates 28 refineries would be involved in this program. The contaminated soil removed in the retrofitting process would be landfilled. While this assumes the soil is not RCRA hazardous, it does assume that the soil be disposed of in a RCRA landfill. The five refineries in Group b could incur an estimated one-time cost of $0.71 billion, about 27 percent of the total one-time costs.

- Remove contaminated soil to landfill, $6.60 billion. The total 187 refineries are involved in this sensitivity analysis. The contaminated soil is assumed to be nonhazardous and is placed in a RCRA type landfill. The 24 refineries in Group f could incur the largest incremental one-time cost of $2.44 billion, about 37 percent of the total cost of $6.60 billion.

- Remove active hazardous SWMUs and incinerate soil, $1.55 billion. The NPC survey indicates 14 refineries would be involved in this program. The contaminated soil is removed and the assumption is made that the material is incinerated, 50 percent onsite and 50 percent offsite. The four refineries in Groups g and h would be impacted by about $0.24 billion.

- Remove contaminated soil from under replaced light and heavy hydrocarbon storage tanks and landfill the soil, $0.51 billion. All 187 refineries are involved in this sensitivity analysis. Old storage tanks are replaced and contaminated soil under leaking tanks is removed and placed in a RCRA type landfill. The 14 refineries in each Group f and h could incur large one-time costs for disposing of the contaminated soil from under the leaking tanks, $0.14 billion per group.

NPC has considered four regulations of having limited probability of being imposed. Their estimated one-time costs are presented in Table ES-9.

- Retrofit surface improvements and incinerate contaminated soil, $7.54 billion. The NPC survey indicates 28 refineries would be involved in this program. The contaminated soil is assumed to be a RCRA hazardous waste and is incinerated offsite. The five refineries in Group b would incur about $2.00 billion in one-time costs, about 26 percent of the total cost of $7.54 billion.

- Remove contaminated soil and incinerate, $83.56 billion. All 187 refineries are involved in this sensitivity analysis. The contaminated soil is assumed to be hazardous waste and therefore would be incinerated offsite. The 24 refineries in Group f would incur the largest incremental one-time cost of $30.76 billion, about 37 percent of the total cost of $83.56 billion.

- Remove inactive hazardous SWMUs and incinerate soil, $85.12 billion. All 187 refineries are involved in this sensitivity analysis. The contaminated soil is removed and the assumption is made that the material is incinerated, 50 percent onsite and 50 percent offsite. The 14 refineries in each Group f and h and the 8 refineries in Group i would incur major one-time costs, $25.91 billion, $23.25 billion, and $16.61 billion, respectively.

- Remove contaminated soil from under replaced light and heavy hydrocarbon storage tanks and incinerate the soil, $2.37 billion. The total 187 refineries are involved in this sensitivity analysis. Old storage tanks are replaced and treatment of the contaminated soil under leaking tanks is done by incineration. The 14 refineries in each Group f and h could incur large one-time costs for incinerating the contaminated soil from under the leaking tanks, $0.65 billion and $0.57 billion, respectively.

Table ES-8
COST OF POSSIBLE LINE ITEMS THAT COULD BE IMPOSED BY REGULATIONS
($ BILLION)

Item	Capital Investment	One-Time Costs
Air Sector		
VOC from PRVs on Large Columns and Fractionators, Header/Flare System	0.72	-
Hazardous and Nonhazardous Solid Waste Sector		
Retrofit Surface Impoundments, Landfill Contaminated Soil	-	2.67
Remove Contaminated Soil to Landfill	-	6.60
Remove Active Hazardous SWMUs and Incinerate Soil	-	1.95
Remove Contaminated Soil From Under Replaced Light and Heavy Hydrocarbon Storage Tanks and Landfill the Soil	-	0.51
Total	0.72	11.73

Table ES-9
COST OF POSSIBLE LINE ITEMS THAT HAVE LIMITED PROBABILITY OF BEING IMPOSED BY REGULATIONS
($ BILLION)

Item	One-Time Costs
Hazardous and Nonhazardous Solid Wastes Sector	
Retrofit Surface Impoundments, Incinerate Contaminated Soil	7.54
Remove Contaminated Soil and Incinerate	83.56
Remove Inactive Hazardous SWMUs and Incinerate Soil	85.12
Remove Contaminated Soil from Under Replaced Light and Heavy Hydrocarbon Storage Tanks and Incinerate the Soil	2.37
Total	178.59

1.O INTRODUCTION

1.0 INTRODUCTION

Bechtel Corporation has been retained by the National Petroleum Council (NPC) to assist them in conducting a study to determine the economic impact on the U.S. refining-marketing industries to meet present and potential EPA regulations:

- Air
- Wastewater
- Hazardous and Nonhazardous Solid Wastes
- Safety and Health

Bechtel's part of the overall NPC Study was to determine the environmental control systems and programs that would be required by the U.S. refineries to meet the NPC's environmental premises. Bechtel defined the environmental control systems and programs and then estimated the capital expenditures, operating and maintenance (O&M) expenses, and one-time costs of the required facilities and programs.

The estimated capital investment values are based on mid-1990 U.S. Gulf Coast construction rates. The O&M expenses were developed utilizing mid-1990 U.S. Gulf Coast unit costs for labor, utilities, and chemicals. Maintenance expenses were estimated as a percentage of capital investment. One-time expenses were developed utilizing mid-1990 U.S. Gulf Coast conditions.

NPC defined the time periods in which the control systems and programs may be implemented. The three periods are:

- 1991 through 1995
- 1996 through 2000
- 2001 through 2010

NPC premises do not cover all environmental expenditures that the U.S. refining industry will be incurring for the 1991 through 1995 period. However, the NPC premises do provide continuity for the methodology Bechtel employed to develop investments and costs for the two other time periods: 1996 through 2000 and 2001 through 2010. **Although Bechtel developed investment and cost values for the NPC premises for the 1991 through 1995 period, the NPC Task Force elected to base their work on survey response data in that period. The survey information includes all refinery environmental expenditures for the 1991 through 1995 period.**

The Department of Energy (DOE) reported that there were 187 operating and idle refineries as of January 1, 1991, with total crude distillation capacity of 16,425,500 barrels per stream day (BPSD). It is assumed these 187 refineries will exist through the 1991 to 2010 period. Therefore, all environmental investment and costs values are based on a constant refining population.

The 187 refineries were assigned to nine groups based on crude capacity. The refineries within each of the nine groups established an average refinery in regard to processing and offsite complexity. Therefore, the environmental control systems and programs to be installed by refineries within each of the nine groups are similar in process configuration and size. This averaging concept provides better estimates of investments, one-time costs, and O&M expenses for the environmental control systems and programs that are required.

A number of sensitivity analyses were made on the seven premises as requested by the NPC Task Force. These analyses are shown at the end of each environmental sector in the report.

2.0 BASIS

2.0 BASIS

Bechtel's contribution to the overall NPC Study was to determine the environmental control systems and programs associated with the U.S. refining industry requirements to meet the NPC's environmental premises. Bechtel defined the environmental control systems and programs then estimated the capital expenditures, O&M expenses, and one-time costs of these required facilities and programs. The following assumptions were used to develop the database from which the required environmental control systems and programs were estimated.

2.1 U.S. Petroleum Refining Industry Characteristics

The following criteria were used in preparing process configuration and the supporting facilities and utility systems for the U.S. petroleum refining industry:

- Operating and idle refineries as of January 1, 1991
- Operating and idle refineries with crude distillation capacity
- Offshore refinery capacity is not included; refineries (operable or idle) in Puerto Rico and Virgin Islands are not included

Utilizing the list of U.S. refineries prepared by the DOE and the above criteria, there were 187 operating refineries as of January 1, 1991, with total a crude distillation capacity of 16,425,000 BPSD.

The 187 refineries were divided into nine groupings (Table 2-1) by crude distillation capacity as follows:

Group	Crude Capacity, BPSD		
a	1,000	-	10,000
b	10,001	-	25,000
c	25,001	-	50,000
d	50,001	-	75,000
e	75,001	-	100,000
f	100,001	-	150,000
g	150,001	-	200,000
h	200,001	-	300,000
i	300,001	-	Plus

The 57 refineries that have crude distillation of 100,001 BPSD plus, account for over 70 percent of the crude distillation capacity.

Table 2-1

U.S. OPERATING AND IDLE REFINING CAPACITY (as of 01/01/91)

Grouping	No. of Refineries	Total Capacity, kBPSD	Percent	Average Capacity, kBPSD
a	26	175	1.1	6.8
b	24	400	2.4	16.6
c	40	1,545	9.4	38.7
d	28	1,730	10.5	61.8
e	12	1,060	6.4	88.2
f	24	3,025	18.4	126.0
g	11	1,935	11.8	175.7
h	14	3,545	21.6	253.2
i	8	3,010	18.4	376.3
Total	187	16,425	100.0	--

Table 2-2 represents an additional division of the refineries into the five Petroleum Administration for Defense (PAD) Districts. The five PAD Districts are identified in Figure 2-1.

2.2 Typical Process Configuration

Assumptions utilized to develop the simplified block flow diagrams of the process configuration associated within each of the nine groupings of refineries were processing unit capacities as stated in:

- Processing unit capacities in DOE reports and *Oil & Gas Journal* articles
- Processing facilities in operation as of January 1, 1991
- Estimated process configurations that contain the atmospheric crude distillation unit and associated processing facilities for upgrading the 650 °F minus hydrocarbon streams. Process configurations of Group i refineries (300,001 BPSD plus crude capacity) are illustrated in Figure 2-2.
- Estimated process configurations that contains the vacuum distillation unit and associated processing facilities for upgrading the 650 °F plus hydrocarbon streams. Process configurations of Group i refineries (300,001 BPSD plus crude capacity) are illustrated in Figure 2-3.

Table 2-2

U.S. OPERATING AND IDLE REFINERIES GROUPED BY NUMBER, SIZE, AND PAD DISTRICTS (AS OF 01/01/91)

No. of Refineries	PAD Districts					
Grouping	No. 1	No. 2	No. 3	No. 4	No. 5	Total
a	5	3	10	2	6	26
b	2	2	8	3	9	24
c	3	6	13	10	8	40
d	2	13	7	2	4	28
e	1	3	3	-	5	12
f	4	4	8	-	8	24
g	4	3	3	-	1	11
h	-	3	8	-	3	14
i	-	1	7	-	-	8
Total	21	38	67	17	44	187

Crude Capacity, kBPSD	PAD Districts					
Grouping	No. 1	No. 2	No. 3	No. 4	No. 5	Total
a	30	20	65	15	45	175
b	30	35	140	50	145	400
c	120	225	475	395	330	1,545
d	115	810	450	105	250	1,730
e	85	255	275	-	445	1,060
f	485	555	950	-	1,035	3,025
g	700	525	535	-	175	1,935
h	-	715	2,035	-	795	3,545
i	-	360	2,650	-	-	3,010
Total	1,565	3,500	7,575	565	3,220	16,425

Figure 2-1

PETROLEUM ADMINISTRATION FOR DEFENSE (PAD) DISTRICTS

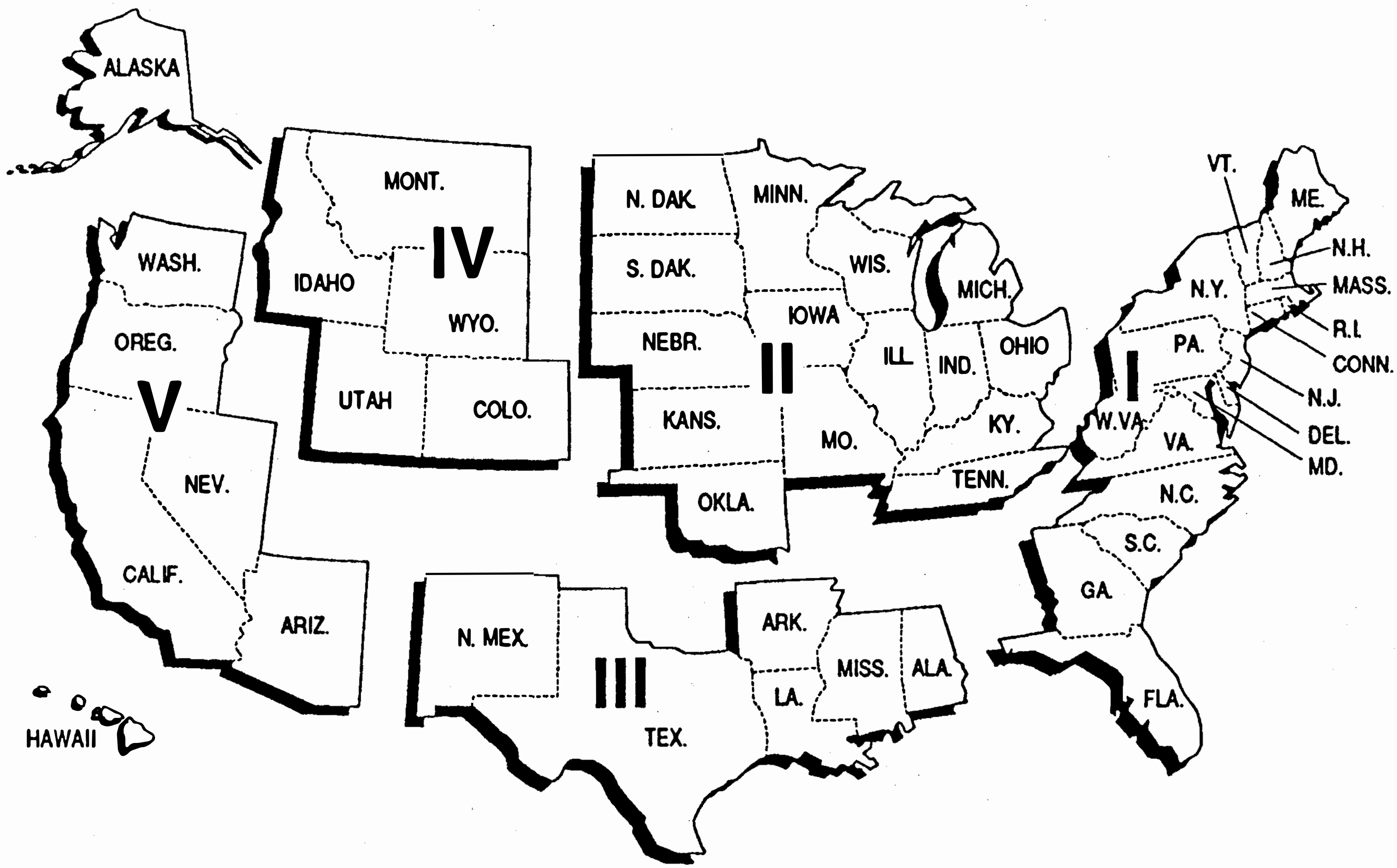


Figure 2-2

PROCESS CONFIGURATION FOR REFINERIES IN THE 300,001 BPSD PLUS Crude Distillation Capacity Range

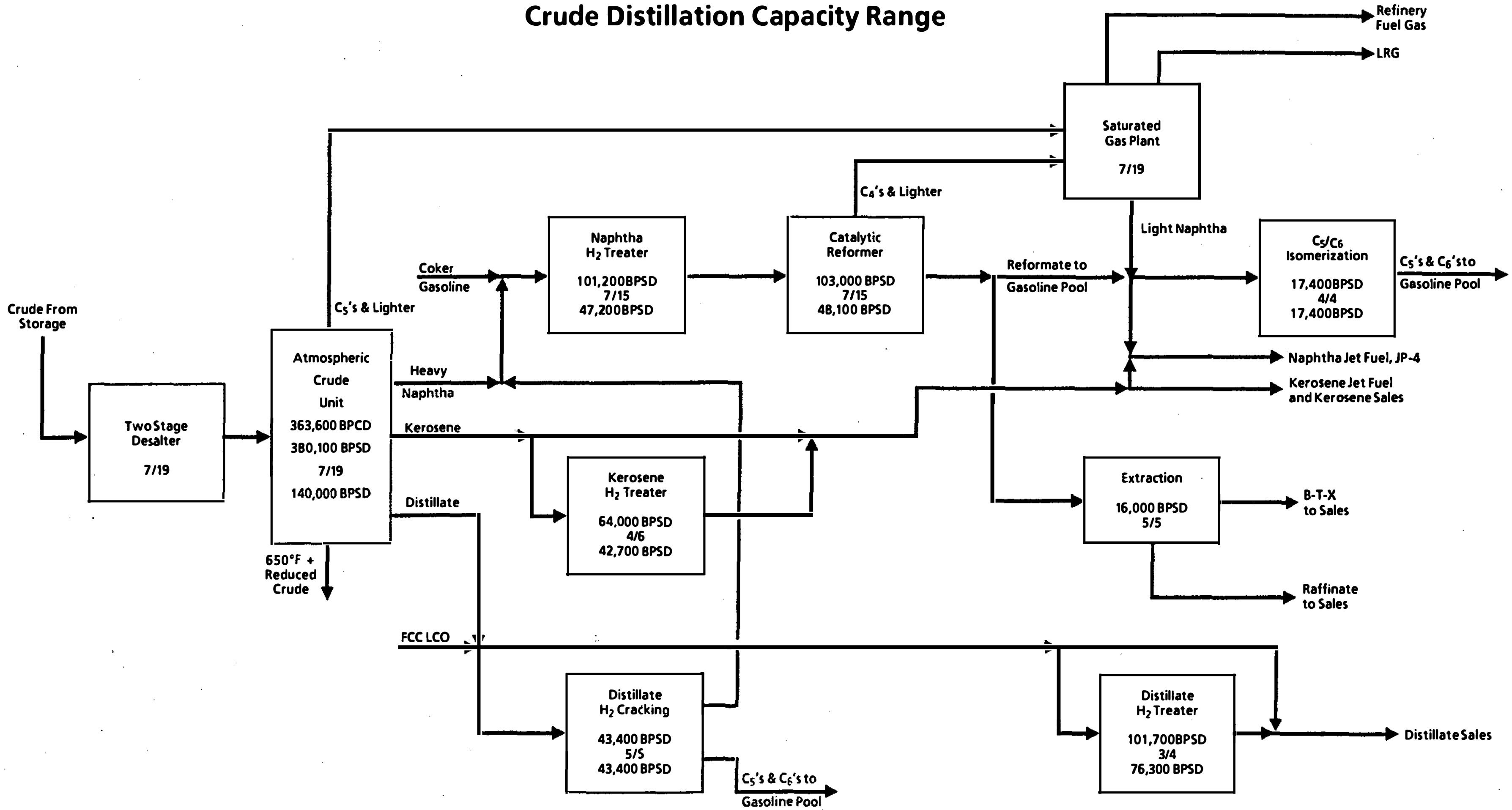
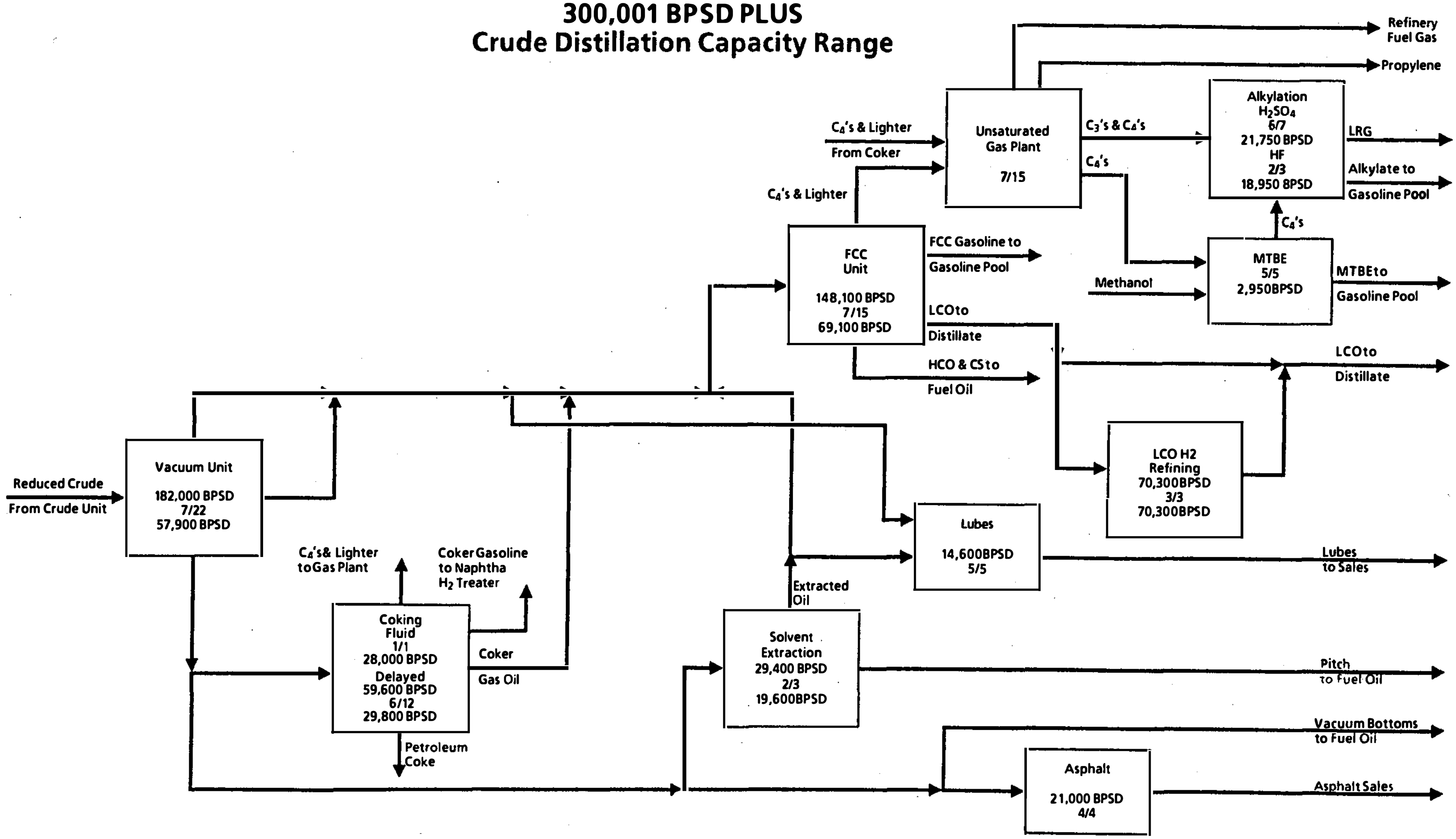


Figure 2-3

PROCESS CONFIGURATION FOR REFINERIES IN THE 300,001 BPSD PLUS Crude Distillation Capacity Range



Process units are shown on the block flow when two or more units are in operation within the grouping. Processing unit capacity is reported two ways:

- Average capacity by number of refineries having the processing facilities
- Average capacity by number of total units

Example: 4/7 within a processing system. There are four refineries that have the processing unit. There are seven processing units within the four refineries.

2.2.1 Desalters

U.S. vendors of crude oil desalters were contacted. They reported that to their knowledge all U.S. refineries have desalting units associated with their crude oil distillation units. Furthermore, it is assumed that single-stage desalters are in refineries with capacities between 1,000 BPSD to 25,000 BPSD. Refineries with capacities greater than 25,000 BPSD have two-stage desalters due to more bottom-of-the-barrel conversion units utilized in larger refineries. Each crude distillation unit has its own desalting unit.

2.2.2 Gas Plants

Gas plants within refinery operations perform the function of separating mixed hydrocarbons into purified streams. There are two generic gas plants: saturated gas plant and unsaturated gas plant.

- Saturated gas plants process a mix of light saturated hydrocarbons from a number of processing units and produce fairly pure products. Feed streams to a saturated gas plant may be:

  - Crude distillation gases
  - Crude distillation light naphtha
  - Catalytic reformer stabilizer gases
  - Hydroprocessing unit stripper gases

  Product streams from the gas plant may be:

  - Refinery fuel gas
  - Propane
  - Mixed butanes
  - Light naphtha

It is assumed that in small refineries, saturated gas plants are installed to recover Liquefied Refinery Gases (LRG) from crude units and catalytic reformers. In large refineries the number of gas plants are tied to the number of crude units.

- Unsaturated gas plants process a mix of light paraffinic/olefinic hydrocarbons from a number of processing units and produce fairly pure products. Feed streams to an unsaturated gas plant may be:

  - FCC fractionator overhead gases
  - FCC light gasoline
  - Thermal processing unit stabilizer gases

  Product streams from the gas plant may be:

  - Refinery fuel gas
  - Propane/propylene
  - Butanes/butylenes

  It is assumed that a refinery with an FCC unit will have an unsaturated gas plant. The number of unsaturated gas plants each refinery has is based on the number of FCC units within the refinery.

2.2.3 Hydroprocessing

There are three types of hydroprocessing facilities in the U.S. refining industry. They are:

- Hydrotreating, essentially no reduction in molecular size of feed occurs; mild desulfurization and/or olefinic saturation
- Hydrorefining, 10 percent or less of the feed is reduced in molecular size; severe desulfurization, denitrification, and aromatic saturation
- Hydrocracking, 50 percent or more of the feed is reduced in molecular size

2.2.4 Lubes

The manufacturing of bulk lube stocks can require a number of processing steps. The simplified process configuration shows a single block for lube operations.

2.2.5 Asphalt

Asphalt blending stock may be produced directly off the vacuum unit or, depending on the crude oil being processed, the vacuum bottoms may require air blowing. Insufficient data is not available to identify refineries that have asphalt air blowing facilities.

2.2.6 Solvent Extraction

Some refineries process vacuum bottoms through a solvent extraction facility. The extracted oil may be routed to the lube facilities or be fed to a FCC unit or a heavy oil hydrocracker.

2.2.7 Treating Units

Chemical and non-chemical treating systems on propane, mixed butanes, light naphtha, jet fuels, etc., that utilize technologies from several major process licensors are not included in the description of the refinery configuration. However, these units are considered when determining operating labor requirements.

2.3 Supporting Facilities and Utility Systems

The following assumptions were utilized to develop an estimate of the supporting facilities and utility systems associated within each of the nine groupings of U.S. refineries crude distillation capacity. The data utilized to develop the facilities and systems were from the DOE reports and *Oil & Gas Journal* articles. The estimated supporting facilities and utility systems configuration for those refineries in Group i (300,001 BPSD plus crude capacity) is presented in Figure 2-4.

2.3.1 Tankage

There are three groups of tankage within a refinery:

- Crude oil and other raw materials
- Intermediate products
- Finished products

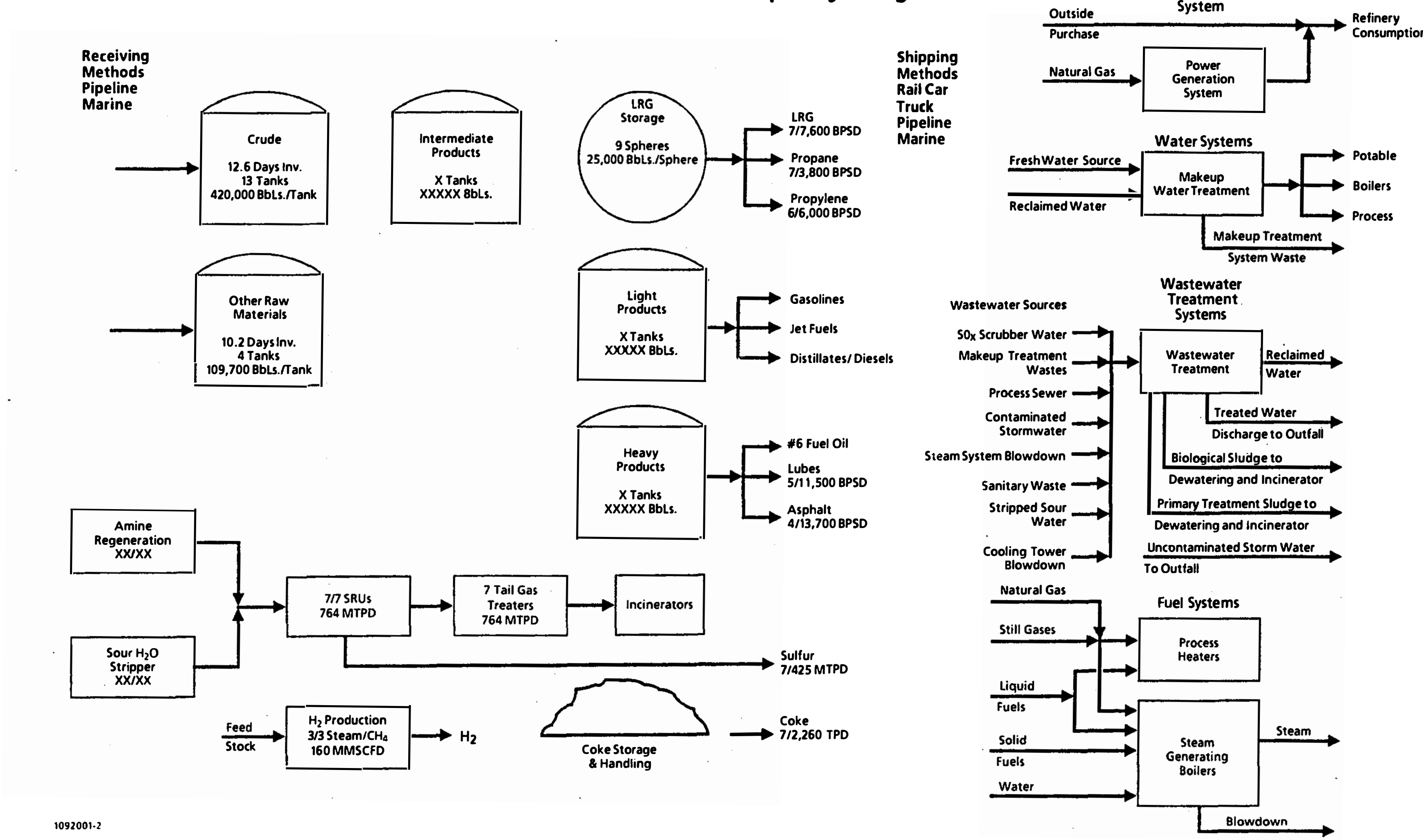
DOE reports crude oil shell storage capacity by PAD District as of January 1, 1991, to be:

PAD District	Storage Capacity, 1,000 Barrels	Crude Capacity, kBPSD	Maximum Days Inventory
No. 1	25,803	1,565	16.5
No. 2	28,019	3,500	8.0
No. 3	96,926	7,575	12.8
No. 4	4,682	565	8.3
No. 5	45,805	3,220	14.2

The maximum days of crude oil inventory for each district is then based on the crude oil distillation capacity and the crude oil storage capacity. The estimated maximum crude oil inventory within each of the nine refinery groupings is a weighted average of crude distillation capacity of each district's refineries within the group.

Figure 2-4

SUPPORT FACILITIES AND UTILITIES FOR REFINERIES IN THE 300,001 BPSD PLUS Crude Distillation Capacity Range



1092001-2

The number and capacity of crude oil tankage were determined for each refinery grouping based on the following assumptions:

Grouping	Crude Capacity, kBPSD	Crude Oil Inventory, Days	No. of Tanks	Tank Capacity Barrels
a	6.8	13.7	3	35,800
b	16.6	13.1	4	67,700
c	38.7	11.4	5	100,700
d	61.8	11.1	6	131,600
e	88.2	12.3	7	181,300
f	126.0	13.8	7	325,000
g	175.7	13.9	8	386,700
h	253.2	12.6	8	443,100
i	376.3	12.6	13	420,000

Tank capacity should be of sufficient volume to contain a minimum of two days crude oil charge. Also, tank capacity is a standard size with a maximum height of 48 feet. The days of crude oil inventory aids in determining the size (land requirement) of the tank farm.

DOE reports shell storage capacity for finished refined products of motor gasolines, middle distillates, jet fuels, residual fuel oils, asphalts, and lubes by PAD District as of January 1, 1991, to be:

PAD District	Storage Capacity, 1,000 Barrels	Crude Capacity, kBPSD	Maximum Days Inventory
No. 1	73,775	1,565	47.1
No. 2	85,466	3,500	24.4
No. 3	145,601	7,575	19.2
No. 4	16,682	565	29.5
No. 5	58,773	3,220	18.2

The maximum days of finished product inventory for each district is then based on the crude oil distillation capacity and the finished product storage capacity. A simple assumption is made: the finished product yield is equivalent to crude oil input. The estimated finished product inventory within each of the nine refinery groupings is a weighted average of crude distillation capacity of each district's refineries within the group. The tankage capacity of finished product inventory aids in determining the size (land requirement) of the tank farm.

Additionally, the values of tankage numbers and capacities were derived from responses of six questions from the NPC Survey. Refinery tankage, as defined by the NPC Survey, was in two groupings: light hydrocarbons (>0.75 psi vapor pressure) and heavy hydrocarbons (<0.75 psi vapor pressure). The number of light hydrocarbon tanks in 187 refineries is estimated at 7,101. The type of tank and age of the light hydrocarbon tankage is presented in Figure 2-5. The number of heavy hydrocarbon tanks in 187 refineries is estimated at 11,123. The type of tank and age of the heavy hydrocarbon tankage is presented in Figure 2-6.

The estimated investment for the modified and new tankage will be assigned to three environmental sectors:

- The estimated investment for domes are assigned to the Air Sector

- The estimated investment to retrofit all existing storage tanks (light and heavy hydrocarbons) with double bottoms are allocated to the Wastewater Sector - Groundwater Issues, groundwater pollution from storage tanks

- Replacement of 50 percent of the light and heavy hydrocarbon tanks over 40 years old. The estimated investment for replacement of tanks is allocated to the Hazardous and Nonhazardous Solid Wastes Sector - Groundwater

LRG storage will be in pressure tanks to handle mixed butanes, propane, and propylene. Estimated propane yields are based on refineries that have fluid catalytic cracking units and associated alkylation or polymerization units. Average propane yields are based on 1990 refinery yields as reported by DOE.

Estimated propylene yields are based on refineries that are reported to be producers/marketers of propylene streams. Propylene stream may be refinery, chemical, or polymer grade. Average propylene yields are based on 1990 refinery yields as reported by DOE.

LRG storage type is based on using pressurized bullet-type tanks in small refineries that fall into the following two groups of crude distillation capacity:

- 1,000 BPSD to 10,000 BPSD

- 10,001 BPSD to 25,000 BPSD

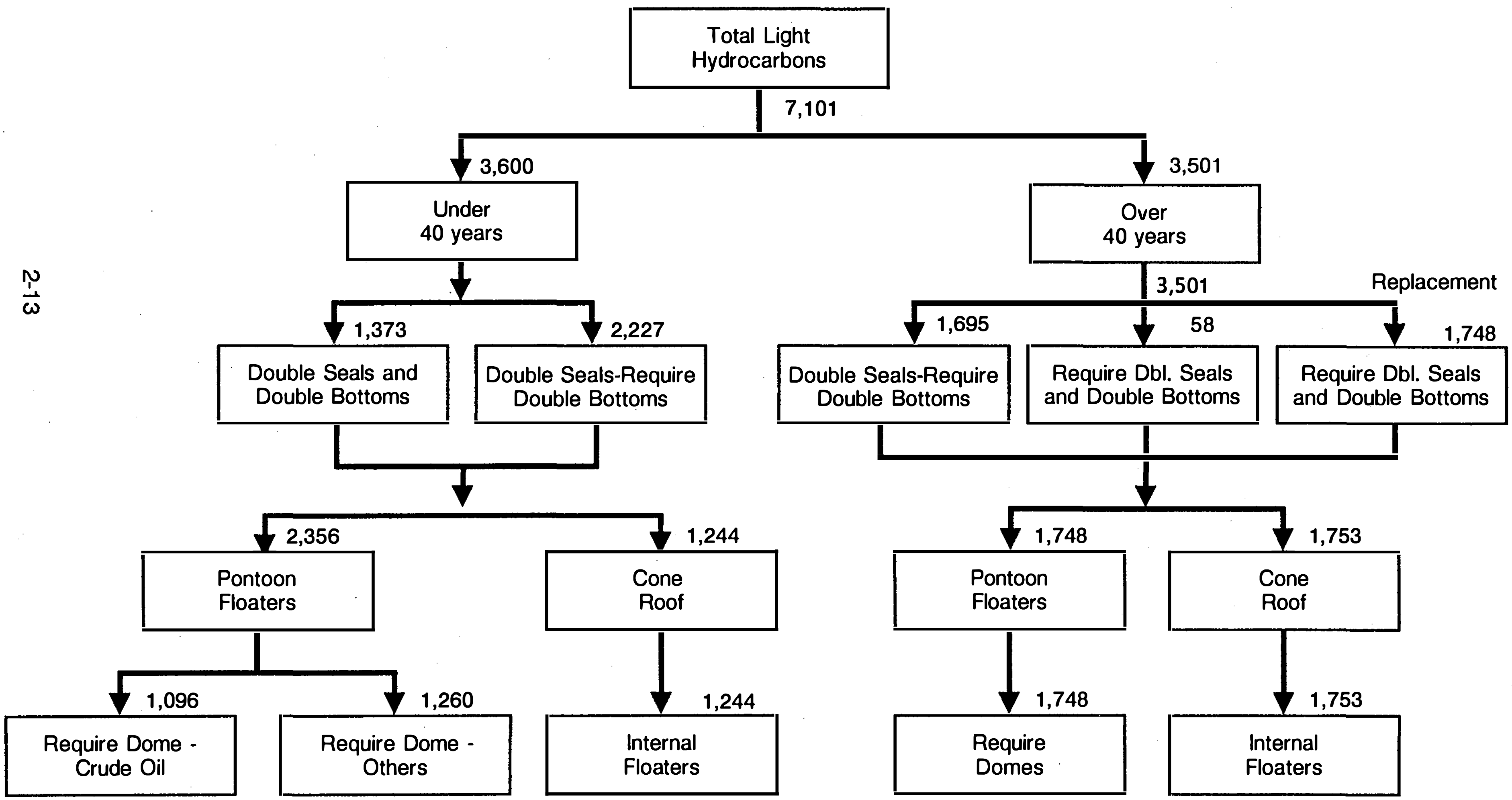
Pressurized storage in larger refineries is assumed to be in spheres. Number of bullets or spheres at a refinery is based on two storage vessels per product. Capacity of a bullet-type tank or sphere is based on a five-day inventory of the LRG product.

2.3.2 Asphalt

Estimated asphalt yields are based on reported producers of asphalt and based on 1990 refinery yields as reported by DOE. It is assumed that asphalt will be bulk shipped from heated storage tanks.

Figure 2-5

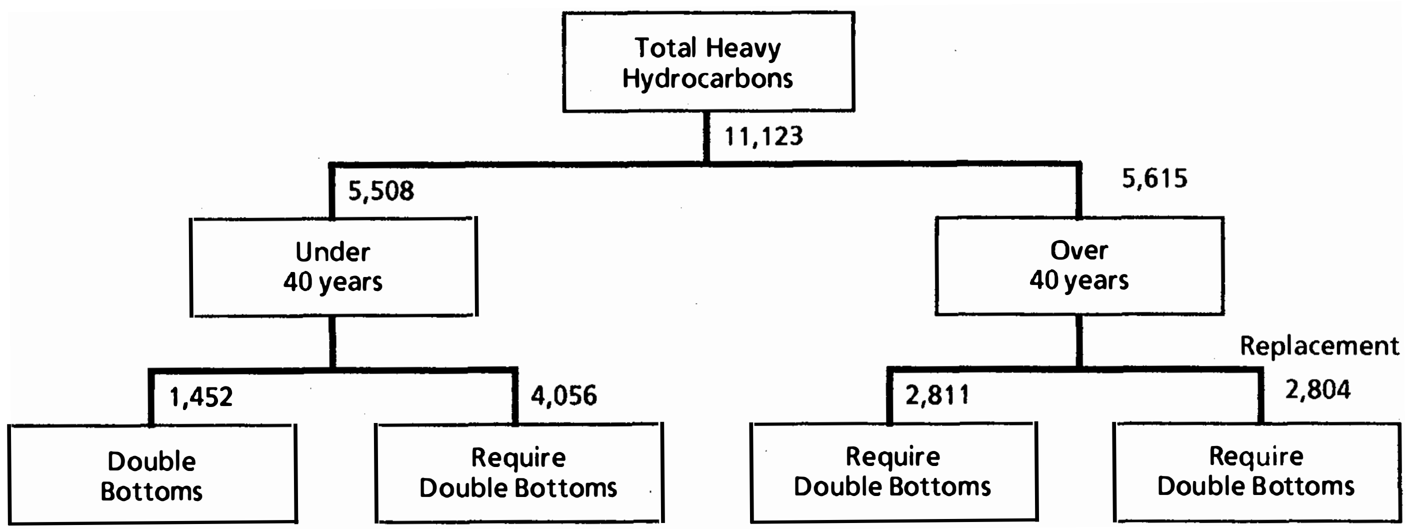
LIGHT HYDROCARBON TANKAGE



1092001-2

Figure 2-6

HEAVY HYDROCARBON TANKAGE



2.3.3 Lubes

Estimated lube yields are based on reported producers of lubes and based on 1990 refinery yields as reported by DOE. It is assumed that lubes will be bulk shipped from refinery storage.

2.3.4 Petroleum Coke

Estimated petroleum coke yields are based on reported producers of coke from delayed and fluid coking units and based on 1990 refinery yields as reported by DOE. Coke inventory stored at the refinery in enclosures is assumed to be 10 days of production.

2.3.5 Sulfur

Sulfur recovery units and their capacities are from DOE reports and *Oil & Gas Journal* reports. Estimated sulfur recovery quantities are from *Oil & Gas Journal* reports and data from the U.S. Bureau of Mines.

Estimated number and capacity of tail gas treaters are based on refineries that recover 20 or more metric tons of sulfur per day. Recovered sulfur will be stored and shipped from the refinery in a molten phase. Liquid sulfur inventory at the refinery is assumed to be five days of production.

2.3.6 Power

In estimating the power system configuration of refineries with crude distillation capacity under 50,000 BPSD, it is assumed they will purchase all their power needs. Refineries with crude oil distillation capacity over 50,000 BPSD may generate some or all of their power requirements.

2.3.7 Wastewater Treatment System

The systems illustrated are ones currently being installed by the large refineries. The small refineries will modify their existing wastewater treatment systems to the updated systems to meet wastewater environmental regulations.

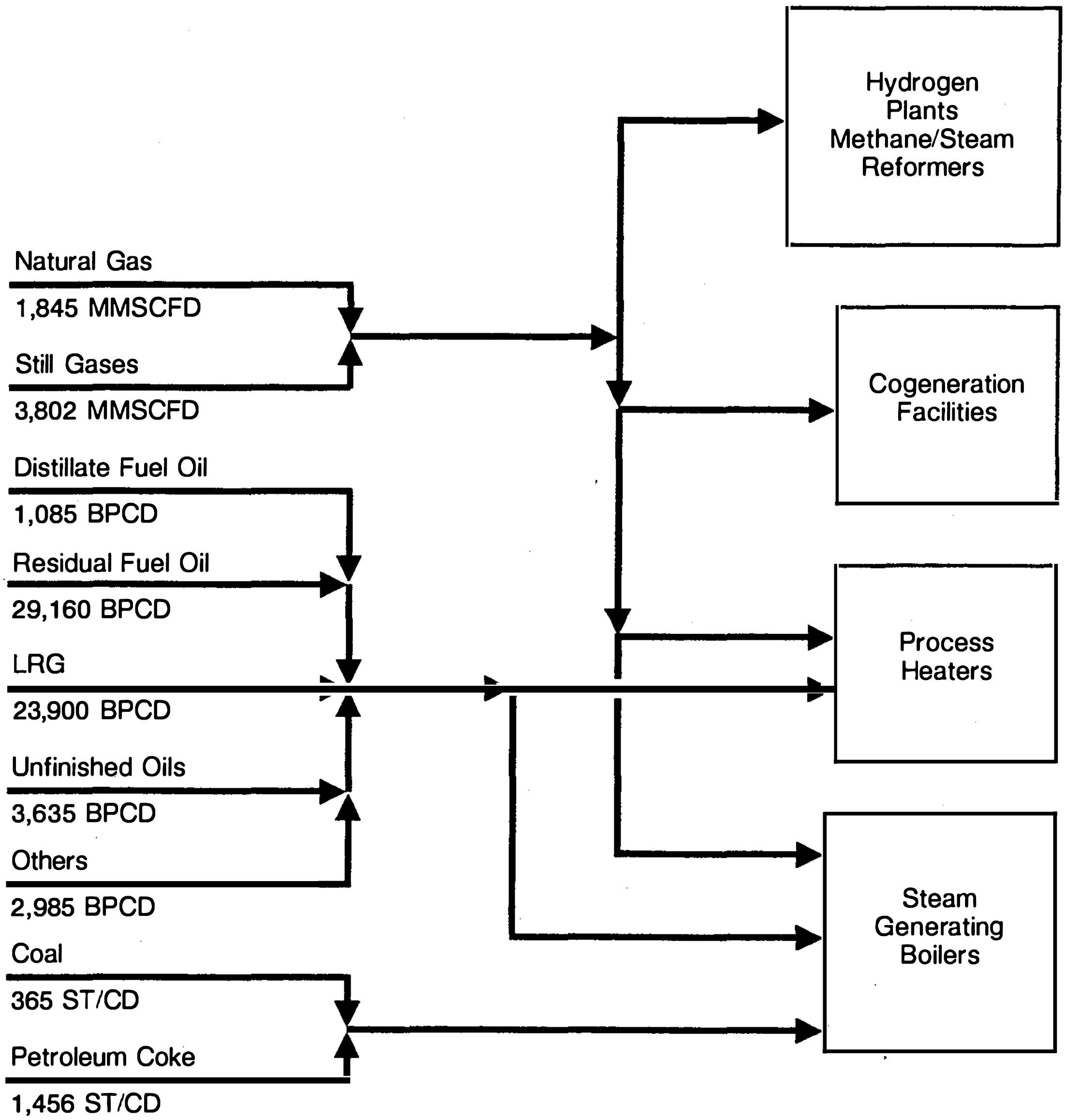
2.3.8 Fuel Systems

Refinery process heaters will normally be fired with a mix of still gases and purchased natural gas. At certain refineries, natural gas is not readily available and liquid fuels are fired in process heaters. Liquid fuels may be distillate fuel oils, residual fuel oils, whole crude oils, or liquefied petroleum gases.

Fuels fired in steam boilers may be still gases, natural gas, or liquid fuels and in limited application - solid fuels. Solid fuels may be coal or marketable petroleum coke. The mix of fuels consumed at U.S. refineries during 1990 as reported by DOE is presented in Figure 2-7.

Figure 2-7

TOTAL FUEL
CONSUMED AT U.S. REFINERIES - 1990



Source: DOE "Petroleum Supply Annual - 1990"

2.4 Refinery Staffing

In developing estimated capital charges, one-time charges, and annual operating expenses for a refiner to meet certain safety and health regulations, the need to know the manpower for a refinery operation is required. The NPC Survey did not provide the staffing number at refineries; therefore, an estimate of typical manpower requirements was developed. The estimated staffing requirements was performed for four groupings: operating, maintenance/contract, support staff, and administration. The estimated total staff per average refinery per grouping is:

Grouping	Crude Capacity, BPSD	Total Staffing Per Refinery
a	6,800	62
b	16,600	93
c	38,700	233
d	61,800	337
e	88,200	458
f	126,000	680
g	175,200	930
h	253,200	1,420
i	376,300	2,090

2.5 Refinery Land Requirements

In developing estimated capital charges, one-time charges, and annual operating expense for a refiner to meet certain air, wastewater, and hazardous and nonhazardous solids environmental regulations, the need to know the land occupied by a refinery is required. The NPC Survey did not provide this information. Therefore, an estimate of land required by a typical refinery was developed. The estimated utilized land required per average refinery per grouping is:

Grouping	Crude Capacity, BPSD	Land Requirements, Per Refinery, Acre
a	6,800	17
b	16,600	35
c	38,700	86
d	61,800	137
e	88,200	187
f	126,000	315
g	175,700	473
h	253,200	539
i	376,300	804

2.6 Capital Investment

Capital investment of each environmental control device and/or program is presented as total installed costs and includes all material, labor, subcontracts, field indirects, and engineering costs and fees.

Exclusions and qualifications are:

- All capital estimates are in mid-1990 U.S. dollars
- Estimates are based on Texas Gulf Coast, Bechtel engineering and procurement, and open shop construction
- Catalyst, chemicals, license/royalty fees, and know-how fees are included when applicable
- No owner-related costs have been included
- No forward escalation has been included
- No contingency has been included
- No site preparation costs have been included (clear, level site was assumed)

2.7 One-Time Costs

Utilized same assumptions as Capital Investment.

2.8 Operating and Maintenance (O&M) Expenses

The O&M expenses for each environmental control device were developed utilizing mid-1990 U.S. Gulf Coast unit costs for labor, utilities, and chemicals. Maintenance (labor and material) expenses were estimated as a percent of capital investment.

2.9 NPC Premises

The NPC Environmental Task Force provided Bechtel with the environmental, safety and health premises. These were based on applicable present and pending EPA regulations that the U.S. refining industry will be required to comply with during the 1991-2010 time frame. Also, NPC provided the three time periods by which the U.S. refining industry will comply with the premises. The listing of premises and their implementation schedules are in their respective sector.

2.10 NPC Survey

A 10-section survey was sent by NPC in late 1991 to all refineries comprising the U.S. petroleum refining industry as of January 1, 1991. The consolidated responses to questions in two sections of the survey were utilized by Bechtel to aid in developing the control systems and/or programs to meet the NPC premises.

The two sections of the survey that Bechtel utilized were:

- Section III - Refinery Emission Sources and Controls
- Section IV - Economic Impacts of Environmental Regulations On Refineries - Historical and Anticipated Costs

3.0 AIR SECTOR

3.0 AIR SECTOR

Refinery air emissions will be reduced during the late 1990s and first decade of the 21st century. Improvements in ambient air quality and reduction of toxic emissions will result from a number of regulatory initiatives that target air emissions.

The incremental cost estimates for the U.S. refining industry to meet the NPC's premises on air regulations are:

	$ Million						
Item	**1991-1995**	**1995**	**1996-2000**	**2000**	**2001-2010**	**2010**	**Total**
Capital Investment	3,537	---	1,874	---	2,090	---	7,501
One-Time Costs	9	---	29	---	---	---	38
Total	3,546	---	1,903	---	2,090	---	7,539
O&M Expenses	---	228	---	454	---	152	---

Note: Costs are expressed in mid-1990 U.S. Gulf Coast dollars.

3.1 Regulatory Drivers

Refinery operators will be required to reduce air emissions in response to a variety of regulatory drivers. Various regulatory initiatives will target refineries and require specific actions to reduce emissions. The regulatory initiatives will be principally targeted toward criteria pollutants for which ambient air quality standards have been enacted. It is possible that by 2010 a regulatory program will be in place to also limit emissions of certain greenhouse gases, such as carbon dioxide (CO_2), as a control measure for global warming.

Many of the regulatory drivers which will affect air emissions during the next 20 years are already in place. Those which are known were used explicitly to develop the premises for the costs. Additionally, the NPC Study team extrapolated other regulatory drivers from local pollution control initiatives that are expected to become the norm nationwide.

3.1.1 <u>Ambient Air Quality</u>

3.1.1.1 Clean Air Act Amendments of 1990. The Clean Air Act Amendments (CAAA) of 1990 have several titles which will affect the petroleum refining industry by causing them to further reduce air emissions from stationary sources. The new regulations will require modifications to equipment, and enhanced inspection and maintenance programs to reduce fugitive emissions.

The specific titles in the CAAA which will affect refineries are:

- Title I. Nonattainment - Areas which fail to meet the National Ambient Air Quality Standards (NAAQS) for the criteria pollutants will be expected to further reduce emissions. States must develop their own State Implementation Plans (SIPs) for each area, addressing the particular pollutant for which they are in nonattainment. These plans must specify steps that will be taken to achieve the standard within a given period of time. They must describe emission limits that will be imposed upon industrial sources. These measures will vary by pollutant and by the degree of nonattainment.

The most widespread nonattainment problem facing the United States is ozone for which nearly 100 urban areas fail to meet the standard. Previous strategies to meet the ozone standard focused on reducing emissions of volatile organic compounds (VOC). The new act specifically requires that nitrogen oxide (NO_x) be assessed for its contribution to the formation of ozone and included in the compliance strategy, along with further VOC reductions.

Implementation plans developed by the states must include reductions of VOC in the ozone nonattainment areas. NO_x emissions will also be reduced as part of the effort to attain the air quality standard for ozone. Much of the NO_x reduction strategy will focus on boilers and heaters used by utilities and industrial facilities.

There are 98 ozone nonattainment metropolitan areas in the U.S. and these areas are illustrated in Figure 3-1. There are five sub-groupings of ozone nonattainment. The sub-groupings are based upon the degree by which the areas have been observed to exceed the one-hour ozone standard of 0.120 ppm. The design value is the second highest concentration observed in that particular area and is a useful method to rank the groups. The five groupings are:

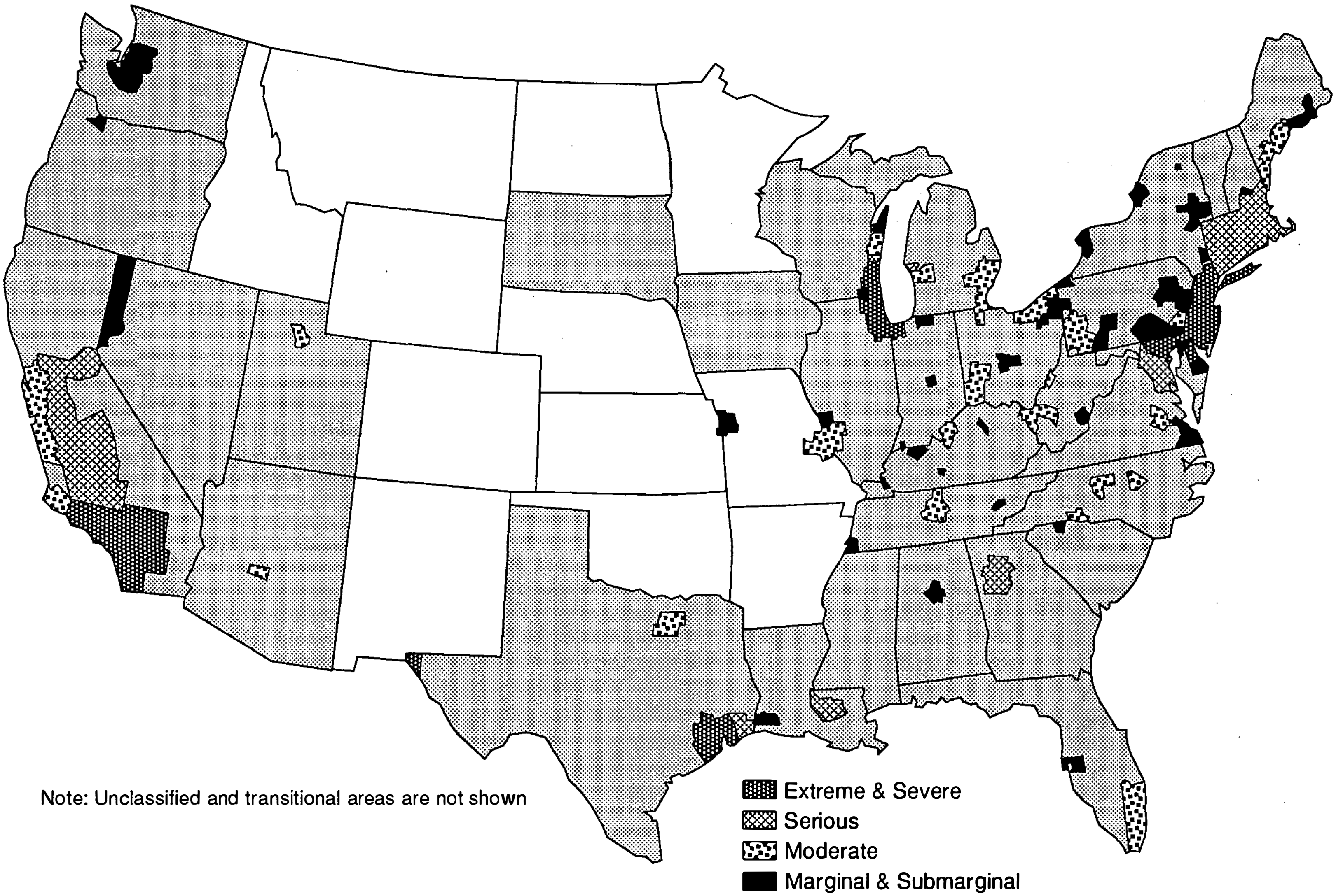
Group	**Design Value, ppm**
Marginal	$\geq$ 0.121
Moderate	$\geq$ 0.138
Serious	$\geq$ 0.160
Severe	$\geq$ 0.180
Extreme	> 0.280

Table 3-1 presents the number of refineries in ozone attainment and each nonattainment category by the nine refinery groups. About half of the refineries are in this group of nonattainment areas. However, when considering crude capacity, data in Table 3-2 shows that about 70 percent of the total U.S. crude capacity is located in ozone nonattainment areas. Fourteen refineries sited in the extreme ozone area are in the Los Angeles Basin. These 14 refineries are of varying crude capacity and they fall into six of the nine refinery groupings.

There are 42 CO nonattainment areas in the U.S. These areas are illustrated in Figure 3-2. An area is classified as nonattainment if the ambient concentration of CO exceeds 35 ppm during any one-hour period.

Figure 3-1

AREAS DESIGNATED NONATTAINMENT FOR OZONE



Note: Unclassified and transitional areas are not shown

1093029-1 MAC

Table 3-1

NUMBER OF U.S. REFINERIES IN OZONE ATTAINMENT AND NONATTAINMENT AREAS

		Ozone					
			Nonattainment				
Grouping	No. of Refineries	Attain-ment	Marginal	Moderate	Serious	Severe	Extreme
a	26	17	-	5	1	1	2
b	24	16	1	4	2	-	1
c	40	22	2	5	6	1	4
d	28	15	4	3	1	3	2
e	12	9	-	1	1	1	-
f	24	9	-	5	1	6	3
g	11	2	-	1	2	6	-
h	14	1	-	3	6	2	2
i	8	1	-	1	3	3	-
Total	187	92	7	28	23	23	14
Percent	100.0	49.2	3.7	15.0	12.3	12.3	7.5

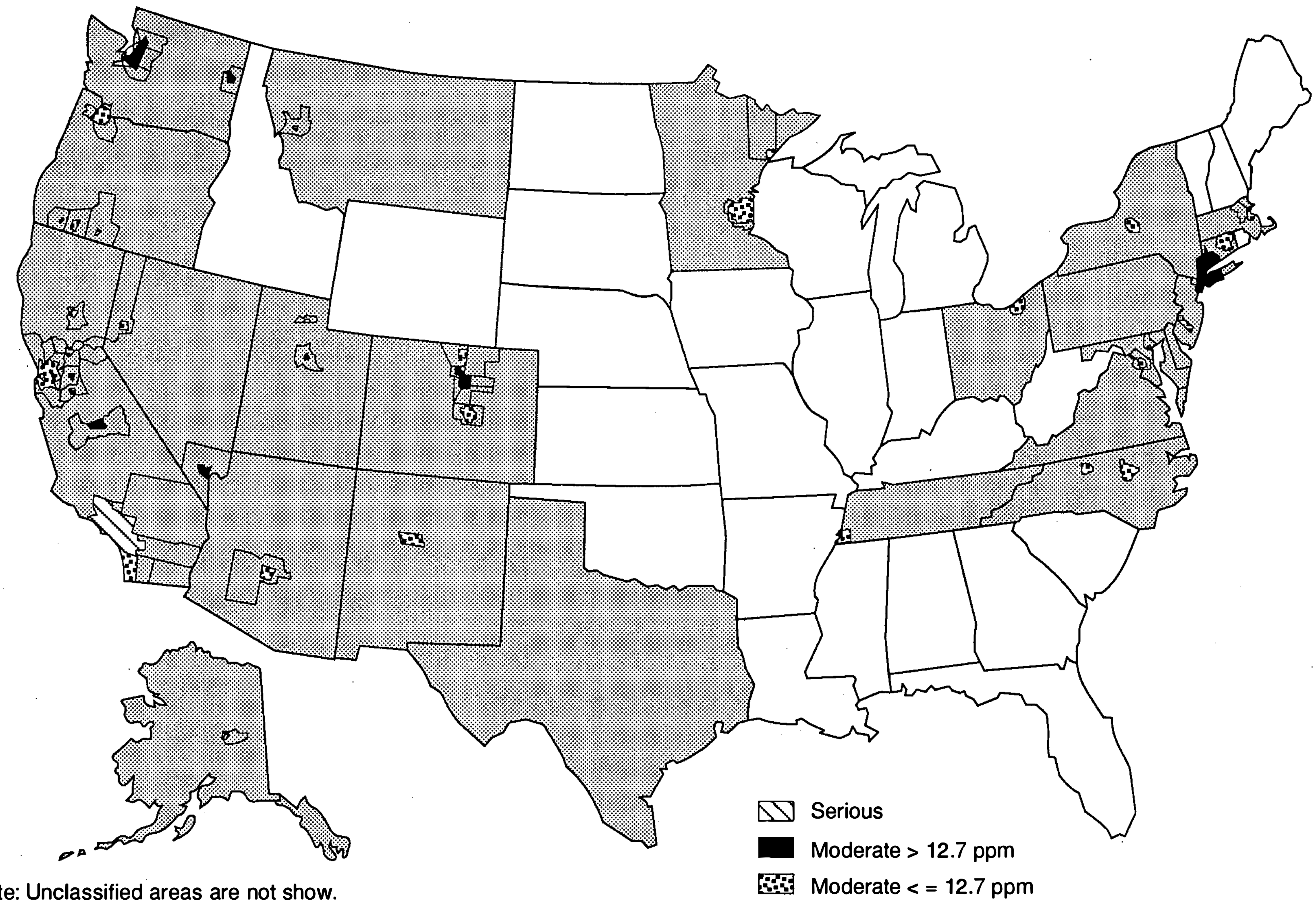
Table 3-2

REFINERY CRUDE CAPACITY (kBPSD) IN OZONE ATTAINMENT AND NONATTAINMENT AREAS (AS OF 01/01/91)

		Ozone					
			Nonattainment				
Grouping	Crude Capacity, kBPSD	Attain-ment	Marginal	Moderate	Serious	Severe	Extreme
a	175	115	-	35	5	5	15
b	400	255	15	75	40	-	15
c	1,545	820	80	190	230	50	175
d	1,730	880	235	190	70	215	140
e	1,060	795	-	80	100	85	-
f	3,025	1,150	-	680	115	715	365
g	1,935	350	-	165	325	1,095	-
h	3,545	210	-	785	1,510	525	515
i	3,010	310	-	320	1,110	1,270	-
Total	16,425	4,885	330	2,520	3,505	3,960	1,225
Percent	100.0	29.8	2.0	15.4	21.3	24.1	7.4

Figure 3-2

AREAS DESIGNATED NONATTAINMENT FOR CARBON MONOXIDE



Note: Unclassified areas are not show.

1093029-1 MAC

Table 3-3 presents the number of refineries in CO attainment and nonattainment areas by the nine refinery groups. About 23 percent of the refineries are in CO nonattainment areas. However, when considering crude capacity, data in Table 3-4 shows that about 21 percent of the total U.S. crude capacity is located in CO nonattainment areas. The 48 refineries in the CO nonattainment areas vary in crude capacity and they fall into seven of the nine refinery groups. Twenty-one refineries are small refineries; less than 50,000 BPSD crude capacity.

There are 70 PM-10 nonattainment areas in the U.S. These areas are illustrated in Figure 3-3. An area is classified as nonattainment when particles less than 10 microns in diameter have an annual mean concentration of 50 μg per m^3 or 150 μg per m^3 in 24 hours.

Table 3-3 presents the number of refineries in PM-10 attainment and nonattainment areas by the nine refining groups. About 17 percent of the refineries are in PM-10 nonattainment areas. However, when considering crude capacity, data in Table 3-4 shows about 12 percent of the total U.S. crude capacity located in PM-10 nonattainment areas. The 31 refineries are of varying crude capacity and they fall into six of the nine refinery groupings. Twenty-one refineries are small refineries, less than 50,000 BPSD crude capacity.

There are 50 SO_2 nonattainment areas in the U.S. These areas are illustrated in Figure 3-4. An area is classified as nonattainment if the average concentration of SO_2 exceeds 0.14 ppm in a 24-hour period or 0.03 ppm on an annual basis.

Table 3-3 presents the number of refineries in SO_2 attainment and nonattainment areas. About seven percent of the refineries are in SO_2 nonattainment areas. When considering crude capacity, data in Table 3-4 shows about seven percent of the total U.S. crude capacity is located in SO_2 nonattainment areas. The 13 refineries are of varying crude capacity and they fall into six of the nine refinery groups.

- Title III. Air Toxics

Prior to the signing of the CAAA of 1990, only a few air toxics known as Hazardous Air Pollutants (HAPs) had been identified and regulated by the EPA, under the National Emission Standards for Hazardous Air Pollutants (NESHAP). The CAAA recognized that the HAP problem in the United States was a major public health concern and was multifaceted; as such, the air toxics requirements have been categorized into three key areas for implementation:

- Routine air toxics emissions from stationary sources
- Accidental releases of air toxics
- Air toxics emissions from mobile sources

Table 3-3

NUMBER OF U.S. REFINERIES IN CO, PM-10, AND SO_2 ATTAINMENT AND NONATTAINMENT AREAS

Grouping	No. of Refineries	Carbon Monoxide		PM-10		SO_2	
		Attainment	Non-attainment	Attainment	Non-attainment	Attainment	Non-attainment
a	26	23	3	24	2	26	-
b	24	18	6	17	7	22	2
c	40	28	12	28	12	35	5
d	28	21	7	24	4	26	2
e	12	10	2	12	-	12	-
f	24	15	9	21	3	22	2
g	11	11	-	11	-	11	-
h	14	10	4	11	3	13	1
i	8	8	-	8	-	7	1
Total	187	144	43	156	31	174	13
Percent	100.0	77.0	23.0	83.4	16.6	93.0	7.0

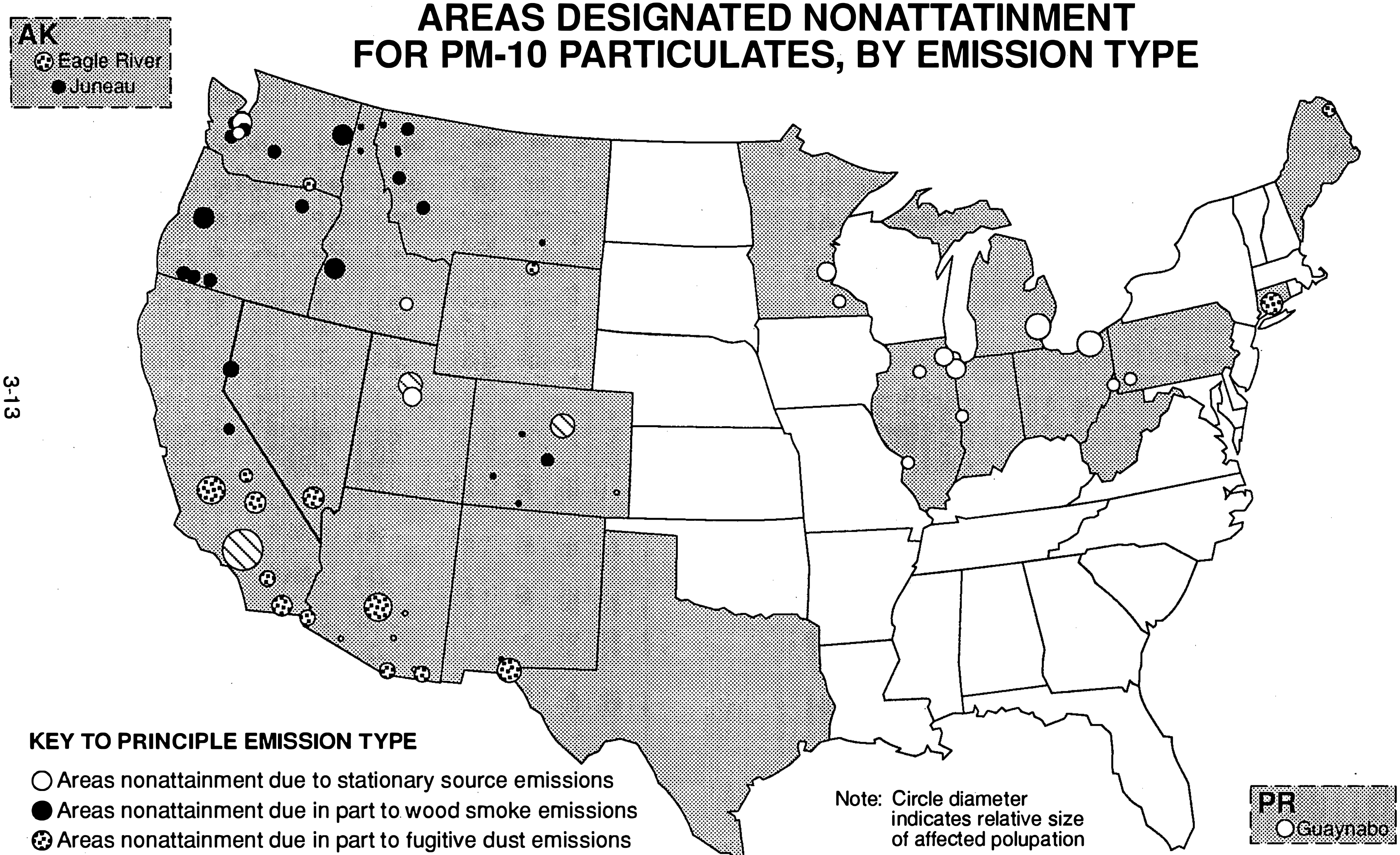
Table 3-4

REFINERY CRUDE CAPACITY (kBPSD) IN CO, PM-10, and SO_2 ATTAINMENT AND NONATTAINMENT AREAS (AS OF 01/01/91)

		Carbon Monoxide		PM-10		SO_2	
Grouping	Crude Capacity kBPSD	Attainment	Non-attainment	Attainment	Non-attainment	Attainment	Non-attainment
a	175	155	20	160	15	175	-
b	400	295	105	280	120	360	40
c	1,545	1,070	475	1,070	475	1,345	200
d	1,730	1,265	465	1,455	275	1,630	100
e	1,060	890	170	1,060	-	1,060	
f	3,025	1,885	1,140	2,660	365	2,765	260
g	1,935	1,935	-	1,935	-	1,935	-
h	3,545	2,540	1,005	2,820	725	3,325	220
i	3,010	3,010	-	3,010	-	2,650	360
Total	16,425	13,045	3,380	14,450	1,975	15,245	1,180
Percent	100.0	79.4	20.6	88.0	2.0	92.8	7.2

Figure 3-3

AREAS DESIGNATED NONATTATINMENT FOR PM-10 PARTICULATES, BY EMISSION TYPE



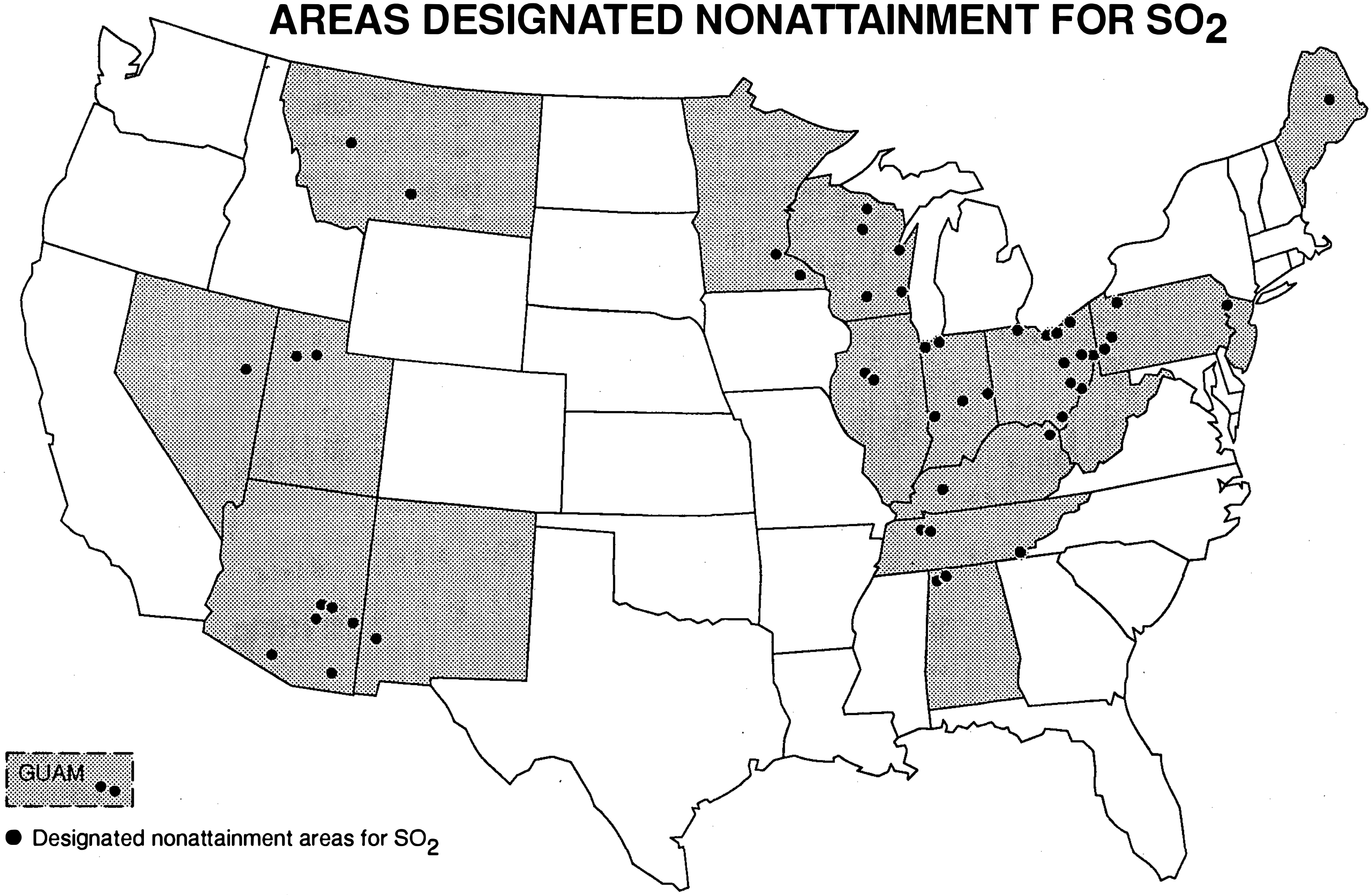
KEY TO PRINCIPLE EMISSION TYPE

- ○ Areas nonattainment due to stationary source emissions
- ● Areas nonattainment due in part to wood smoke emissions
- Areas nonattainment due in part to fugitive dust emissions
- Areas nonattainment due to multiple types of emissions

1093029-1 MAC

Figure 3-4

AREAS DESIGNATED NONATTAINMENT FOR SO_2



● Designated nonattainment areas for SO_2

1093029-1 MAC

Those requirements dealing with routine air toxics emissions from stationary sources and accidental releases of air toxics are the primary air toxics regulations impacting the petroleum refining industry.

It was determined by congress that a set of standards, known as Hazardous Organic NESHAP (HON), should be developed to control air toxics emissions from stationary sources. These standards will require that Maximum Achievable Control Technology (MACT) be applied to each defined source category. Under the CAAA, the EPA is required to publish a list of categories of major sources of the HAPs (listed in Section 112 of the CAAA), publish a 10-year regulatory schedule for developing MACT standards for every category, and develop MACT standards for a certain percentage of the listed categories within specified time frames. The pollutants that will be subject to MACT at petroleum refineries were identified by EPA in a July 1992 release of the source category list. They are:

- Acetaldehyde
- Benzene
- Cadmium compounds
- Formaldehyde
- Hexane
- Hydrogen fluoride
- Lead compounds
- Mercury compounds
- Methanol
- Methyl ethyl ketone
- Nickel compounds
- Propylene oxide
- Selenium compounds
- Toluene
- Xylenes (mixed)

MACT for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) is among the first 40 source categories scheduled for proposal. It is expected that MACT for refineries will not be proposed until sometime in the mid-1990s; however, the MACT proposed for SOCMI will be a good indicator of what is most likely to be required for the petroleum refining industry.

The proposed MACT rules describe specific controls for transfer operations, storage vessels, process vents, and wastewater collection and treatment. They also incorporate a new set of standards for inspection and repair of equipment leaks.

- Title V. Permitting - It was anticipated that the permitting program mandated by the CAAA would be proposed in 1992. (This program has since been finalized by EPA, June 1992). The states must submit their permitting program implementation plans to the EPA on November 15, 1993. At that time, EPA has one year to approve or disapprove the plan. If the plan is disapproved, the states have six months in which to correct the plan.

  Once the states' implementation plans have been approved by EPA, the states must issue all permits within three years. All permit programs submitted for approval to EPA must include a requirement for new permits and a permit fee system.

3.1.1.2. State Implementation Planning. The individual states, in their air quality planning efforts, may choose to make rules more stringent than are required in the federal laws. These may deal with methods to reduce emissions that are considered to be a chronic nuisance or create other problems. The states also may require redundant pollution control equipment to ensure that a backup device is available anytime the primary device is out of service.

3.1.2 Global Warming

There are no current regulatory drivers to reduce or control emissions associated with projected global temperature rises attributed to buildups of greenhouse gases. Much of the current attention is focused on CO_2 and methane as predominant greenhouse gases. In the future these may be subject to regulatory controls; however, no emissions controls for these were included in the premise for this study.

3.2 Control Technologies

A set of control technologies has been premised for air emissions sources at refineries. The typical emissions from principal refinery units are shown in Table 3-5.

Table 3-5

CHARACTERISTIC AIR EMISSIONS FOR PRINCIPLE SOURCES AT PETROLEUM REFINERIES

Source	PM	SO_2	CO	VOC	NO_x
FCC units	x	x	x	x	x
Coking units	x	x	x	x	x
Compressor engines		x	x	x	x
Vapor recovery system and flares		x	x	x	x
Vacuum distillation and column condensers				x	
Sulfur recovery units		x	x		x
Wastewater treatment plants				x	
Boilers and process heaters		x	x		x
Storage tanks				x	

The control technologies premised by the NPC are based upon provisions in the CAAA and anticipated features of the rules in the various states that will be promulgated to further improve air quality. The controls will be phased-in mostly during the 1991 through 2000 time frame. The NPC air premises are summarized in Table 3-6.

3.2.1 Control of Particulate Matter

3.2.1.1. Particulates from Combustion. All FCC units will ultimately have high-efficiency electrostatic precipitators to control particulate matter.

Table 3-6

AIR CONTROL TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject (Limit/Scope)	Refinery Size (BPSD)	CONTROL TECHNOLOGY (Percent Implementation)*			
		Attainment	Nonattainment		
PM-10	All	High Efficiency Precipitator[a] (50-50-0)			
SO_x	< 25,000	Sulfur Recovery Unit (SRU) (50-25-25)			
	25,000 - 50,000	SRU + TGU (Tail Gas Unit) (0-75-25)	SRU + TGU + SO_x promoter (50-25-25)		
	> 50,000	SRU + TGU (0-75-25)	SRU + TGU + FCC stack gas scrubber (0-75-25)		
CO	All	b			
NO_x[c]	< 100 MMBtu[d]	None	Extreme	Severe	< Severe
			Heater: ultra low-NO_x burners[e] (50-50-0) FCC[f]: SCR (0-75-25)	Heater: ultra low-NO_x burners[e] (25-75-0) FCC[f]: SCR (0-0-100)	Heater: ultra low-NO_x burners[e] (0-50-50)

a To control metals to comply with MACT.
b Proper operation of existing equipment (CO boiler and process heaters) will satisfy requirements.
c Based on ozone nonattainment.
d Heater size.
e Controlled to 0.05#/MMBtu.
f Independent of heater size.
g Controlled to 0.02#/MMBtu.
h One new flare will be costed per refinery to control emissions from PRVs, process vents, fugitives, etc.
i Sensitivity analysis performed.

* Note: During periods 1991 through 1995, 1996 thorugh 2000, and 2001 through 2010.

Table 3-6 (Cont'd)

AIR CONTROL TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject (Limit/Scope)	Refinery Size (BPSD)	CONTROL TECHNOLOGY (Percent Implementation)*			
		Attainment	Nonattainment		
			Extreme	Severe	< Severe
NO_x[c] (20 ppm - FCC)	>100 MMBtu[d]	None	Heater: SCR[g] (50-50-0) FCC[f]: SCR (0-75-25)	Heater: ultra low-NO_x burners[e] (25-75-0) SCR[g] (0-0-100) FCC[f]: SCR (0-0-100)	Heater: ultra low-NO_x burners[e] (0-50-50)
FUGITIVES (MACT) (pumps, valves, flanges, compressors)	All	Pumps: LO Tandem seals - 5% replacement/yr Valves: 3% replacement/yr Reciprocating Compressors: Box 10% of distance pieces and combust vapors[g] (75-25-0) Enhanced Inspection & Maintenance (I&M)[i]			
PRESSURE RELIEF VALVES	All	Vent to flare (25-50-0)[h,i] (excludes vents from very large towers)			
STORAGE TANKS (MACT) (light products)	All	Internal floaters - no action Tanks with single seals add double seals (25-75-0) Domes on 1/2 of external floaters (0-0-100)			
COKER VENTS	All	Scrubbers (25-75-0)			

a To control metals to comply with MACT.
b Proper operation of existing equipment (CO boiler and process heaters) will satisfy requirements.
c Based on ozone nonattainment.
d Heater size.
e Controlled to 0.05#/MMBtu.
f Independent of heater size.
g Controlled to 0.02#/MMBtu.
h One new flare will be costed per refinery to control emissions from PRVs, process vents, fugitives, etc.
i Sensitivity analysis performed.

* Note: During periods 1991 through 1995, 1996 thorugh 2000, and 2001 through 2010.

O:\PROPOSAL\1093029\NPCTAB

Table 3-6 (Cont'd)

AIR CONTROL TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject (Limit/Scope)	Refinery Size (BPSD)	CONTROL TECHNOLOGY (Percent Implementation)*	
		Attainment	Nonattainment
COKE HANDLING	All	Enclose conveyors and storage (25-25-50)	
WASTE TREATMENT SYSTEM (MACT)	All	Cover and thermal oxidizer primary separation (50-50-0) activated sludge (25-25-50)	
WASTE HANDLING (MACT)	All	Total enclosure (50-50-0)	
H_2S	All	VOC Controls in place - no additional controls costed	
ODOR (MACT)	All	PSM and VOC Controls in place - no additional controls costed	
PERMITS AND FEES	All	$25/ton plus escalation (limit 4000 tons/regulated pollutant/yr)	
OFFSETS	All	No additional costing, included as capital cost of new units	
COMBUSTION/TOXICS	All	Switch to clean fuel (25-75-0)	
UNIT REDUNDANCY	All	Add capacity to handle shut-down of largest "control" units (i.e., precipitators, SRUs, TGUs, spares) (0-25-50)	

a To control metals to comply with MACT.
b Proper operation of existing equipment (CO boiler and process heaters) will satisfy requirements.
c Based on ozone nonattainment.
d Heater size.
e Controlled to 0.05#/MMBtu.
f Independent of heater size.
g Controlled to 0.02#/MMBtu.
h One new flare will be costed per refinery to control emissions from PRVs, process vents, fugitives, etc.
i Sensitivity analysis performed.

* Note: During periods 1991 through 1995, 1996 thorugh 2000, and 2001 through 2010.

O:\PROPOSAL\1093029\NPCTAB

3.2.1.2. Particulates from Coke Handling Equipment. Particulate matter will require controls during coke handling operations. Enclosed conveying and storage will be the system of choice to control particulates containing metals classified as hazardous air pollutants.

3.2.2 Carbon Monoxide (CO) Control

It is expected that CO control will be accomplished through efficiently operating existing equipment (CO boilers and process heaters).

In the Los Angeles area, which is a CO nonattainment area, CO emissions may require additional controls. Stringent reductions of NO_x via combustion controls as part of the ozone attainment strategy, will result in increases of CO. These may require controls through the use of post-combustion devices, such as catalytic incinerators.

3.2.3. Sulfur Dioxide (SO_2) Control

All refineries will be expected to have controls on sulfur dioxide (SO_2) emissions in the future. In SO_2 attainment areas, small refineries (<25,000 BPSD) will have small package sulfur recovery units (SRUs) and intermediate sized facilities (25,000-50,000 BPSD) will have SRUs plus tail gas units to recover sulfur contained in the refinery fuel gases.

In SO_2 nonattainment areas, small refineries will also have small package SRUs while intermediate and large refineries that have hydrotreaters will have SRUs plus tail gas units to recover sulfur contained in the refinery fuel gases.

3.2.4 Control of VOC

Emissions of VOC will be reduced principally through control of equipment leaks and vent recovery systems. It is expected that all VOC/toxics will be controlled by MACT defined in Title III, air toxics rules.

3.2.4.1 Equipment Leaks - Fugitive Sources. An inspection and maintenance program will be required on the major sources of fugitive emissions, such as valves, pumps, and compressor seals. The premise assumes that the limit for leak repair will initially be 500 ppm. A minor amount of capital is required to buy portable analyzer devices and computers for record keeping. The major cost item will be to attach identification tags on each point to be inspected, and the continuing expense for additional personnel or a service contractor to perform the actual monitoring checks.

In ozone nonattainment areas in California, the limit for leak repair is being reduced to 100 ppm. If and when the California rule for definition of a leak is adopted nationwide, it is assumed that in addition to lowering the limit, the rule will also be extended to include monitoring of flanges. It is assumed that leaks will occur on three percent of the items being annually monitored. Adjustments to the leaking components are expected to be more costly, requiring replacement of valve stem packing and/or replacement of old valves and pumps in some cases.

3.2.4.2 Point Sources

Storage tanks for petroleum liquids will require internal floating roofs with double seals or a closed vent collection system connected to a control with at least a 95 percent control efficiency. All process vents will require collection and routing to a recovery system or a control device with an efficiency of 98 percent or better. These are expected to also include vents from cokers.

The proposed controls include use of covers and enclosures on transport and handling equipment with closed vent systems to capture the organic vapors. The requirement for covers will be extended to the biotreatment and primary separation equipment of wastewater systems.

3.2.5. NO_x Control

No controls are expected to be required in ozone attainment areas. In the extreme nonattainment area of southern California, retrofitting of boilers will be necessary to meet NO_x emission limits of 0.04 to 0.06 lb/million Btu. The NO_x limits for process heaters, flue gases, and FCCU regenerator flue gases are premised to be 0.05 lb/MMBtu which could be accomplished only by installing Selective Catalytic Reduction (SCR) systems.

For severe ozone nonattainment areas, the limits on boilers are premised to be 0.06 to 0.08 lb/MMBtu, achievable by using ultra-low NO_x burners on heaters and boilers. In areas designated to be marginal and moderate nonattainment for ozone, all sources will have to meet new source performance standards. For boilers, the applicable limits will be 0.1 to 0.2 lb NO_x/MMBtu, while for gas-fired heaters the limits will be 0.2 to 0.3 lb. These will require some type of combustion control, at least low NO_x burner technology.

3.2.6 Toxics

Emissions of toxics from the combustion of plant fuels is expected to be reduced by switching to natural gas as the primary fuel instead of residual fuel oil.

Toxics, either particulates or gases, from waste handling are also expected to be controlled in the future. The most common waste handled is spent catalyst and it is expected that total enclosures will be required due to the presence of hazardous metals.

3.3 Control Technology Cost Estimate Basis

Control technology specific to each pollutant and type of equipment has been identified. Each of these should satisfactorily meet the requirements of Reasonably Achievable Control Technology (RACT), which is the standard for retrofitting of existing facilities. Where applicable for controlling toxics, costs have been estimated for prescribed MACT.

3.3.1 Particulate Matter - PM-10

FCC catalyst fines that are present in the regenerator flue gas are removed by installing high efficiency electrostatic precipitators, or a wet scrubber, or a third-stage cyclone. Information gathered from licensor, equipment vendors, and the NPC Survey provides guidance as to type of catalyst fines removal systems on existing FCC units. Redundant or new fines removal systems were determined to meet PM-10 regulations. Estimated capital investment and operating expenses were developed for the required systems for refinery groups having FCC units.

Petroleum coke fines reduction program considers one control system. Petroleum coke from a delayed coker will be transferred from the unit by way of a covered conveyor system and stored in a coke storage building.

Small quantities of solid fines are produced when unloading catalytic process reactors. The control system to remove fines emissions will require the installation of a portable system around the bottom of the reactors, collection of the fines, and disposal of the fines in a landfill or return to the catalyst manufacturers.

3.3.2 Carbon Monoxide (CO)

Carbon monoxide content of FCC regenerator flue gas is controlled by passing the flue gas through a CO boiler on air flow-temperature control of the FCC regenerator. Information gathered from equipment vendors indicate a large number of FCC units operating in the U.S. have CO boilers. Therefore, no additional capital investment was assumed to control CO from FCC units.

Carbon monoxide content of process heaters and steam generating boilers flue gases can be controlled by proper firing methods. Therefore, no additional capital investment was assumed to control CO from these two sources.

3.3.3 Sulfur Dioxide (SO_2)

Sulfur dioxide is produced several ways during refinery operations. When liquid hydrocarbon fuels containing sulfur compounds are fired in process heaters and/or steam boilers, SO_2 is produced and is contained in the flue gases.

FCC catalyst leaving the reactor system contains sulfur compounds that are converted to SO_2 in the FCC regenerator. The regenerator flue gases will contain SO_2 and will require treatment before venting to the atmosphere.

When hydrotreating light hydrocarbon fractions (650 °F minus) and/or hydrotreating or thermal processing heavy hydrocarbon fractions (650 °F plus), hydrogen sulfide (H_2S) is produced. The light gases produced are normally chemically treated to remove the H_2S before the gases enter the refinery fuel system. The rich H_2S stream produced by the chemical treater is routed to a SRU where the H_2S is converted to free sulfur.

The systems to control SO_2 produced in refinery operations by the three routes discussed above are:

- Liquid fuels containing sulfur compounds are switched over to natural gas. The costs for this program is covered under fugitive emissions in 3.3.4.1 VOC section.
- Sulfur dioxide contained in FCC regenerator flue gas may be removed by the wet scrubber system or reduced by hydrotreating the FCC feed.

- Install SRUs to process the rich H_2S stream. Information gathered from public sources indicates that about 55 percent of the refineries have SRUs and that these refineries account for 85 percent of crude capacity. Public information and the NPC Survey provided guidance as to the number and capacity of redundant and new SRUs to be installed.

  Tail gas sulfur plants are to be installed in refineries if the SRU recovers 20 or greater metric tons per day of sulfur. The NPC Survey provided guidance as to the number and capacity of redundant and new tail gas sulfur units.

  Capital investment and operating expenses were developed for new and redundant SRUs and tail gas sulfur plants.

3.3.4 Ozone Precursor Controls

3.3.4.1 Volatile Organic Compounds (VOC). VOC may be emitted from at least two points in a refinery wastewater system: primary separation facility and secondary treatment slurry system.

The VOC control system for a primary separation facility covers the system, collects the hydrocarbon off gases, and then incinerates the collected vapors.

The VOC control system for a secondary treatment slurry system covers the system, collects the hydrocarbon off gases, and routes the off gases to charcoal beds.

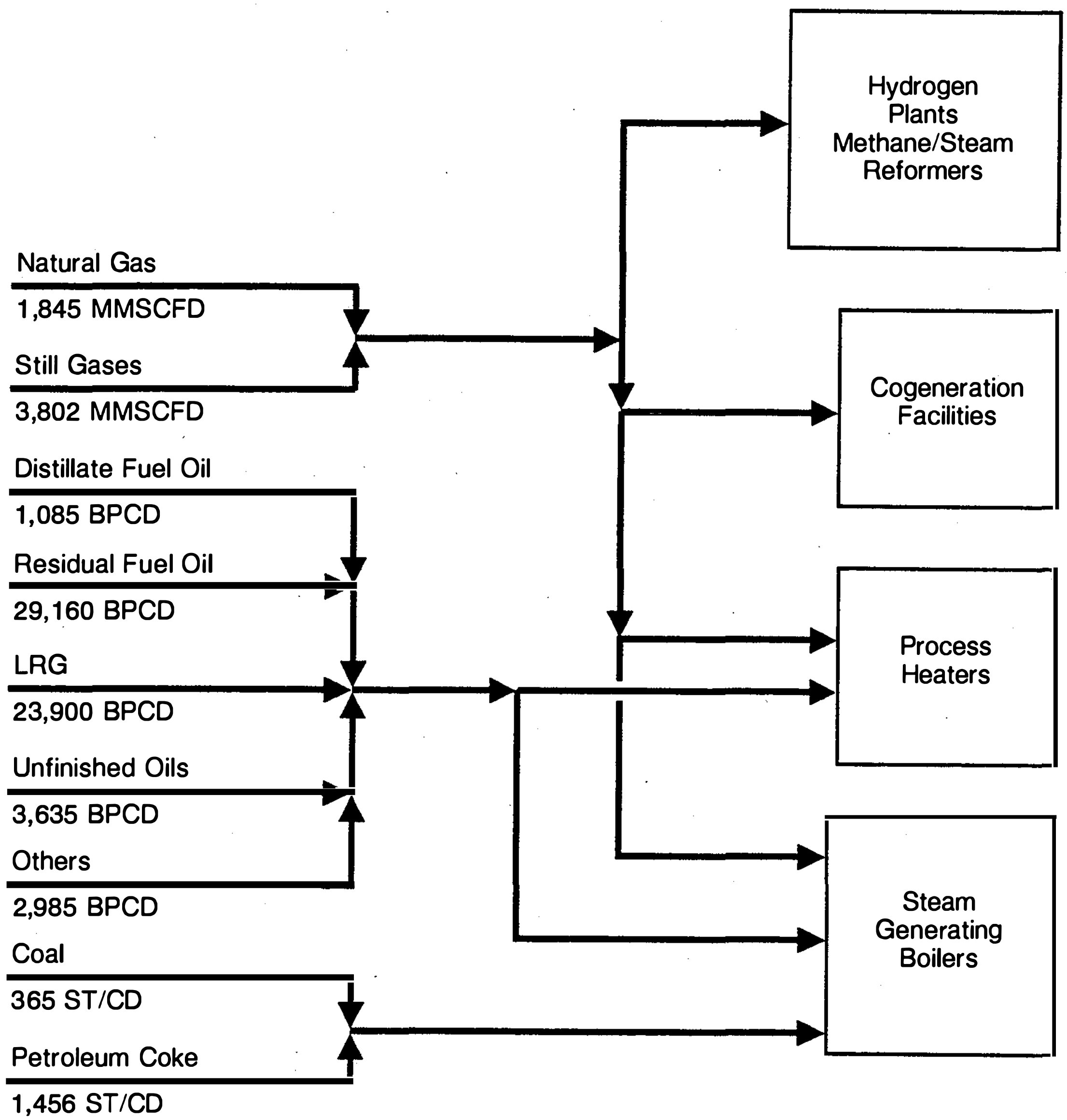
U.S. refinery fuel systems utilize gaseous, liquid, and solid hydrocarbon fuels. Figure 3-5 illustrates the type and quantities of fuels utilized by refineries during 1990. In switching residual fuel oil to natural gas, there could be a reduction in SO_2 and VOC from process heaters and/or steam generating boilers. If one assumes natural gas is available to refineries, the replacement quantity of natural gas would have been about 177 MMSCFD. The unit price of natural gas used for costing purposes was that paid by industrial users in Texas during 1990.

VOC from pressure relief valves (PRVs) that vent to the atmosphere need to be controlled and reduced. It is assumed that a new header system will be installed to collect potential emissions from these PRVs and then routed to a new flare system. Responses from the NPC Survey provided some guidance for estimating the number of PRVs per refinery in each refinery group. The design of the new collection system utilizes pipe of sufficient diameter to carry the estimated VOC loads associated with the processing scheme developed for each refinery group. The sizing of the new flare system was tied to the estimated flaring load.

Crude oil and light hydrocarbon storage tankage is a source of VOC. The control technique to reduce VOC from these sources is to install a dome cover on external floater tankage. The NPC Survey provided some guidance as to the number and tankage capacity that would require domes to be installed. All new replacement tankage in light hydrocarbon service includes a dome cover.

Figure 3-5

TOTAL FUEL
CONSUMED AT U.S. REFINERIES - 1990



Source: DOE "Petroleum Supply Annual - 1990"

1092001-2

Only one source of VOC from process vents is considered -- delayed coking drums. When the coke drums are being decoked, VOC from the top manway of the coke drums is collected and combusted. Estimated capital investment and operating expenses were developed for refinery groups having delayed coking units.

3.3.4.2 Nitrogen Oxides (NO_x). Refinery configurations were estimated for each of the nine refinery groups. The number and average size of the process units were developed and the average process heater duty was estimated. Ultra-low NO_x burners would be installed on process heaters (under/over 100 million Btu/hour) according to the implementation schedules in NO_x nonattainment areas based on NPC's premises.

Insufficient data are available on steam generating boilers to estimate requirements to install ultra low NO_x burners in this service.

SCR systems will be installed on large process heaters (over 100 million Btu/hr) and in FCC regenerator flue gas streams according to the implementation schedules in NO_x nonattainment areas based on NPC's premises.

Insufficient data are available on large steam generating boilers to estimate requirements to install SCRs in this service.

The need for hydrogen to produce clean transportation fuels and the processing by U.S. refineries of lower quality crude oils (lower API and higher sulfur) will compel refineries to recover more hydrogen from refinery gases. Lower hydrogen content in the refinery gases will aid in reducing burner top temperatures and, in turn lower, NO_x production from process heater's burners.

3.3.5 Toxics

The NPC premise designated that control for fugitive emissions would be required to reduce toxic emissions. Equipment counts were estimated as follows:

- The number of process and transfer pumps were estimated for each refinery group. Five percent per year of the pumps seals will be replaced with tandem seals.

- The number of two-inch and larger valves were estimated for each refinery group. Three percent per year of the large valves will be replaced with low emission valves.

- The number of reciprocating compressors were estimated for each refinery group. Ten percent per year of the compressors will be modified to reduce and collect the VOC.

- An Enhanced Inspection and Maintenance (I&M) Program will be installed at each refinery. The program will cover valves, pumps, and compressors at a leak rate to be under 500 ppm. The cost of the I&M programs assume they will be performed by an outside service organization. The initial tagging of equipment will be performed by the service organization.

3.3.6 Permitting Expenditures

The permitting regulations in Title V of the CAAA require states to develop their permit plans during 1992 and 1993. State plans will be submitted to EPA for federal approval during 1994. New permits will be due from facilities in 1995. The new permits will be site-wide and issued for a period not to exceed five years. There will be expenditures related to developing the permit applications and fees accompanying the applications when submitted. The various elements of the permitting expenditures by refinery group are detailed in Table 3-7.

3.3.6.1 Preparing Initial Permit Applications. The permit applications due in 1995 will:

- Consolidate separate permits which may have existed in the past for individual units at a facility.
- Incorporate grandfathered units which have previously not been included in a permit.

Little data may exist for units that have been grandfathered; however, these units will be required to be brought into the permitting program for the first time. It is expected that developing these permit applications will be time and labor intensive.

The cost of developing the permit applications that must be submitted in 1995 will be proportional to the size and complexity of each facility. The number of hours that are estimated for developing the initial applications and negotiating the permit provisions for refineries will likely vary widely, depending on such factors as the number of grandfathered sources, details available on fugitive emissions sources, and the number of units present. To arrive at an estimated cost, the hours needed for permitting in each of the nine groups were assumed as:

Refinery Group	Hours
a	1,200
b	1,600
c	2,000
d	2,500
e	3,000
f	3,500
g	4,000
h	4,500
i	5,000

The applications may be developed by plant personnel or consultants. As part of establishing the emissions from units to be permitted, it is possible that refiners may additionally hire consultants to perform stack sampling.

For costing purposes, an hourly rate of $50 has been used, regardless of whether plant employees or contractors are used. The cost estimates range from $60,000 for a refinery in Group a to $250,000 for Group i.

Table 3-7

SUMMARY OF PERMITTING EXPENDITURES
($1,000)

		1995			2000			2005			2010		
		For Each Refinery											
Refinery Group	Number of Refineries per Group	Prepare Permit Application	Application Fees	Group Total	Prepare Permit Renewal	Renewal Fees	Group Total	Prepare Permit Renewal	Renewal Fees	Group Total	Prepare Permit Renewal	Renewal Fees	Group Total
a	26	60	5	1,690	30.0	5	910	30.0	5	910	30.0	5	910
b	24	80	10	2,160	40.0	10	1,200	40.0	10	1,200	40.0	10	1,200
c	40	100	15	4,600	50.0	15	2,600	50.0	15	2,600	50.0	15	2,600
d	28	125	20	4,060	62.5	20	2,310	62.5	20	2.310	62.5	20	2,310
e	12	150	25	2,100	75.0	25	1,200	75.0	25	1,200	75.0	25	1,200
f	24	175	30	4,920	87.5	30	2,820	87.5	30	2,820	87.5	30	2,820
g	11	200	35	2,585	100.0	35	1,485	100.0	35	1,485	100.0	35	1,485
h	14	225	40	3,710	112.5	40	2,135	112.5	40	2,135	112.5	40	2,135
i	8	250	50	2,400	125.0	50	1,400	125.0	50	1,400	125.0	50	1,400
Total:	187			28,225			16,060			16,060			16,060

Total for period (1995 through 2010): 61,745

In addition to the costs to prepare the permit application, permit application fees are expected to be submitted with each application. These are likely to be based on the value of the facility and, for costing purposes, it is estimated they will range from $5,000 for a Group a refinery to $50,000 for a Group i facility.

3.3.6.2 Permit Renewals. After 1995, a permit renewal will be required at least every five years for every facility. Renewal applications are expected to be due in 2000, 2005, and 2010. The renewal applications for the following years should be less labor intensive than the initial 1995 permits. Estimates of the job hours to prepare each renewal are half of the job hours estimated for the initial application in 1995. The hourly rates used to calculate the costs are the same.

Also, the renewals will likely require a processing fee. The same fee structure ($5,000-$50,000) has been assumed for this calculation, as was used for processing the initial application in 1995.

3.3.6.3 Estimated Permitting Expenditures. The estimated permitting expenditures are expected to total about $28 million for all refineries for the initial submittals in 1995. The subsequent submittals in the years 2000, 2005, and 2010 are expected to be about $16 million per year for all refineries during each five-year cycle. The total for the period 1995 through 2010 will be about $61 million (Table 3-7).

3.3.7 Annual Emissions Fees

The emission fees required in the CAAA must not be less than $25 per ton per year for each regulated air pollutant. Fees can be increased incrementally each year by an amount indexed to the Consumer Price Index. There is a cap of 4,000 tons per year on any regulated pollutant to which the fee will apply for each facility. The fees are payable to the jurisdiction responsible for conducting the regulatory program; either a state, regional, or local authority. States may charge lower fees if they wish, but they must petition EPA and receive approval to do so.

To estimate the fees which will be paid by the petroleum refining industry under this provision, it is necessary to 1.) develop a baseline emissions inventory, 2.) estimate the trend in emissions reductions through compliance with various provisions of the CAAA, and 3.) estimate the annual emission fees (adjusted for emissions reductions and the cap). These estimates were developed for the period beginning in 1994 and continuing until 2010.

3.3.7.1 Baseline Emissions Inventory. To develop a baseline emissions inventory for the refining industry, a sample of refineries was drawn from each of the nine refinery size classes. A request was sent to the EPA for emissions data for the refineries, and it was extracted from its National Emissions Data System (NEDS) database. This was supplemented by Bechtel's database from the Texas Air Control Board listing air emissions for all sources in Texas. The period for which data were available was generally 1987 through 1990.

The number of refinery samples in each of the nine classes ranged from three to seven. The emissions for each grouping were averaged for each of the criteria pollutants. These are presented in Table 3-8 and represent the 1990 baseline emissions estimate for a typical refinery in each of the nine categories. The total emissions of all criteria pollutants for all refineries in the U.S. is estimated to be about 1.376 million tons per year for 1990.

The estimated baseline emissions of SO_2, CO, and PM-10 from petroleum refineries for 1990 compared to industrial and total sources appear to be a minor U.S. source* from reported data:

		Percent of	
Emission	**Million Tons Per Year**	**Industrial**	**Total**
SO_2	0.44	12.8	1.9
CO	0.17	3.3	0.2
PM-10	0.05	1.5	0.6

* U.S.E.P.A., EPA-450/4-91-026, "National Air Pollutants Emission Estimates 1940-1990, November 1991

3.3.7.2 Trends in Emissions Reductions. Emissions reductions will occur as a result of various new regulatory drivers that will begin affecting refineries about 1994. The anticipated trends in refinery emissions nationwide for the period 1990 through 2010 are shown in Table 3-9. It is expected that the effects of the regulatory program to reduce emissions will have made most of its impact on the national emissions inventory by the year 2007. The severe ozone nonattainment areas are required to meet the ambient air quality standard by that time. The assumed reduction trends for each of the criteria pollutants are:

- VOC Reductions - Some VOC emission reductions will occur in the 1992 through 1993 period as a result of the benzene NESHAP Program. Mainly though, VOC, as ozone precursors, will be reduced in response to requirements placed in the individual SIPs that address each ozone nonattainment area. There is a mandated 15 percent reduction in VOC emissions over the six-year period from 1990 through 1996 for areas designated to be in moderate or greater nonattainment. For severe and extreme areas, a further three percent per year reduction from the baseline is mandated from 1996 until attainment is reached. Individual SIPs will describe how these reductions will be achieved through a combination of new controls on mobile, area, and stationary point sources. For refineries, reduction programs are expected for sources of VOCs such as equipment leaks, process vents, pressure relief vents, light products in storage tanks, and wastewater treatment systems.

  Also, VOCs will be reduced as part of the Title III requirements to apply MACT to hazardous air pollutants originating in refineries. The MACT rules for refineries are expected to be promulgated in late 1994. Facilities must take action during the period from 1994 through 1997. Some of the specific sources to be controlled under these rules will be process vents, storage tanks, transfer operations, and equipment leaks.

Table 3-8

1990 GROUP AVERAGE EMISSION ESTIMATES (TONS PER YEAR)

Refinery Group	No. of Refineries Per Group	Emission Per Refinery: VOC	NO_x	SO_2	CO	PM	Total Per Refinery	Total Per Refinery Group
a	26	71	79	5	9	5	169	4,394
b	24	162	414	517	50	69	1,212	29,088
c	40	520	625	469	233	174	2,021	80,840
d	28	3,245	1,551	1,426	511	184	6,917	193,676
e	12	4,647	2,061	3,381	482	290	10,861	130,332
f	24	1,631	3,797	3,754	455	318	9,955	238,920
g	11	3,191	4,981	3,855	2,512	601	15,140	166,540
h	14	2,765	4,856	8,213	1,556	461	17,851	249,914
i	8	6,421	8,371	9,637	9,918	945	35,292	282,336
Total	187							1,376,040

Table 3-9

ESTIMATED TOTAL ANNUAL EMISSIONS FROM REFINERY SOURCES FOR BASE YEAR 1990 AND AFTER REDUCTIONS (1,000 TONS PER YEAR)

Year	VOC	NO_x	SO_2	CO	PM	Total
1990	337.5	386.0	436.4	170.6	45.6	1,376.1
1994	286.9	289.5	436.4	170.6	45.6	1,229.0
1995	275.4	217.1	392.7	170.6	34.2	1,090.0
1996	264.4	162.8	353.5	170.6	25.7	970.5
1997	253.8	122.1	318.2	170.6	19.2	883.9
1998	246.2	91.6	286.3	170.6	14.4	809.1
1999	238.8	68.7	257.7	170.6	14.4	750.2
2000	231.6	61.8	232.0	170.6	14.4	710.4
2001	224.7	55.6	208.8	170.6	14.4	674.1
2002	217.9	50.1	187.9	170.6	14.4	640.9
2003	211.4	45.1	169.1	170.6	14.4	610.6
2004	205.1	40.6	169.1	170.6	14.4	599.8
2005	198.9	36.5	169.1	170.6	14.4	589.5
2006	192.9	32.9	169.1	170.6	14.4	579.9
2007	187.2	29.6	169.1	170.6	14.4	570.9
2008	187.2	29.6	169.1	170.6	14.4	570.9
2009	187.2	29.6	169.1	170.6	14.4	570.9
2010	187.2	29.6	169.1	170.6	14.4	570.9

The premise for the trends in VOC reductions is for a three percent per year reduction in all sources in all ozone nonattainment areas during the period from 1990 through 2007. The year 2007 was used as the final year for costing reductions because it is the year when all ozone nonattainment areas, with the exception of the extreme area, are required to achieve the standard.

- NO_x Reductions - The nonattainment provisions in the CAAA treat NO_x as a precursor of ozone and call for its control as part of the ozone attainment strategy. NO_x emissions must be reduced by applying RACT to existing combustion equipment, such as boilers and heaters. Typical concentrations of NO_x in stack gas from older equipment are about 150 ppm. It is expected that emissions levels in ozone nonattainment areas will be reduced to about 30 ppm.

  These reductions will take place only in ozone nonattainment areas as part of the SIPs. Those plans must be submitted to the EPA by November 1992. EPA has one year to review and approve the plans; source action will take place during the interval from November 1993 to November 1995.

  In extreme areas, a second round of NO_x reductions is required eight years after the enactment of the 1990 Amendments to the CAAA. These require the use of clean fuels in combustion equipment and advanced control technologies such as SCR technology to reduce NO_x emissions.

  For purposes of estimating the annual level of NO_x emissions from all refineries, it is premised that total annual refinery NO_x reductions of 25 percent will occur in every year from 1994 through 2000.

  It is likely that some ozone nonattainment areas will fail to meet the deadlines for attainment in their particular classification. In such cases, the CAAA requires that they adopt control requirements of the next most severe nonattainment category. For example, in a severe area that fails to attain the standard, NO_x controls equivalent to the SCR measures required in the extreme areas will have to be implemented. These will require additional expenditures for NO_x control during the period 2000 through 2010. For costing purposes, reductions of 10 percent per year were assumed for NO_x reductions nationally from 2000 through 2007 when all but the extreme area are required to reach attainment.

- SO_2 Reductions - Sulfur dioxide reductions are expected to occur as the result of measures taken to reduce SO_2 emissions in nonattainment areas and in anticipation of RACT being applied to control these emissions from refineries in all areas. The SO_2 emission reduction measures in the Acid Rain Title of the CAAA are aimed principally at the fossil powered electric utility plants and are not expected to affect refinery sources. Most of the control measures will occur as states implement programs to reduce SO_2 where it is considered a nuisance. The rate of reduction for refinery SO_2 emissions nationwide is projected to be 10 percent per year for the 10-year period from 1994 through 2003 as individual state programs are gradually implemented.

- CO Reductions - There are no anticipated controls to reduce refinery sources of CO emissions in CO nonattainment areas. Improvements in air quality in these areas are expected to be the result of mobile source controls and improving the operation of combustion equipment.

- PM-10 Reductions - Reductions in particulate matter will be in response to the MACT requirements for air toxics. Metals and other toxic particulates associated with FCCUs and coking will be controlled under the provisions of the MACT rules for petroleum refineries expected to be promulgated in 1994. Source compliance with these provisions will then occur during the period from 1994 through 1997. Reductions are expected to be at the rate of 25 percent per year from 1995 through 1998.

3.3.7.3 Estimated Emission Fee Rate Structure. Emission fees are established in the permitting title of the CAAA. There is a minimum fee of $25 per tons per year (TPY) which can be adjusted upward at a rate indexed to the Consumer Price Index. The fee structure will be changing and is anticipated to be as follows:

- 1990 through 2000 - The states must submit their permitting programs to EPA for review by November 1993. EPA has one year to review and approve the plans, then they will be implemented by November 1994. It is expected that the $25 per ton emissions fees will first be paid for the calendar year 1994. Some states began collecting emissions fees prior to the date for conforming with the federal guidance. These initial annual fees implemented prior to the federal requirements in 1994 have not been included in this study.

  In California, the individual air quality management districts establish their own emissions fees and some are already charging over the $25 per ton minimum. In the South Coast Air Quality Management District (SCAQMD) there is a complex fee schedule which varies by pollutant and size of the emission source. The average fee there is about $200 per ton in 1992. In the San Francisco Bay area, the annual emissions fee is about $35 per ton. For purposes of accounting for the higher fees in California, a fee of $100 per ton has been initially used to represent the average for all air quality districts where refineries are located in the state.

  About 14 percent of the total U. S. refining capacity is located in California. Assuming that 14 percent of the emissions will be affected by California's higher rates, special considerations have been made in the calculations of the annual emissions fees. The calculations assume that 14 percent of the fees will be paid at rates of $100 per ton in 1994 while the remaining 86 percent of U. S. refineries in the United States will begin paying fees based on the $25 per ton rate. This weighting yields an average nationwide rate of $36.25 per TPY in 1994, the initial year for the program in all states.

  In order to maintain a constant real source of revenue from fees, the state agencies may increase the amount annually. For costing purposes, it is projected that the increment will be five percent per year for each year after 1995. The rate of increase will be about equal to the rate of total emissions reductions for the refining industry. This will maintain the level of estimated emissions fees paid by refineries in the range of $30 to 40 million per year.

- 2000 through 2010 - The last decade of the 1990s will be one of significant growth for regulatory agencies. Staff increases will be needed to implement the provisions of the CAAA and individual SIPs. The emissions fees will provide much of the funding needed for this growth. Afterwards, it appears that annual emission fees paid by refiners will rise gradually through the period 2000 through 2010 as refinery emissions remain at about 600,000 TPY nationally and emission charges rise from about $50 per TPY to $80 per TPY over that interval.

3.3.7.4 Estimated Emissions Fees. The projected total emissions fees from 1994 through 2010 are shown on Table 3-10. The fees were developed by multiplying the emissions estimate in Table 3-9 by the emission rates described above. Fees paid by the refining industry for the period 1994 through 1995 are expected to be about $74 million. The total for the period 1996 through 2010 for all refineries is projected to be about $511 million. The largest amount over this period ($180 million) will be charged for VOC emissions while the smallest ($13 million) will be charged for particulates.

Table 3-11 shows the emission fees nationwide for each of the refinery groups. For the period 1996 through 2010, the largest amount will be paid by the eight refineries in Group i, over 300,000 BPSD. Their fees are estimated to be about $1,000,000 per year per facility by 2010 based upon a projected emission fee of close to $80 per TPY by that time. The smallest refineries are expected to be paying about $5,000 per year per facility in 2010.

3.4 Summary

3.4.1 Incremental Capital Investment

The estimated incremental capital investment for control systems for reducing air emissions by the U.S. refining industry during the 1991 through 2010 period is $7,501 million (mid-1990 U.S. Gulf Coast). The investment will be spread over five types of emissions as indicated below:

Emission	$ Million	Percent
VOC	3,760	50.1
PM-10	1,628	21.7
SO_2	965	12.9
NO_x	921	12.3
Toxics	227	3.0

Table 3-10

TOTAL EMISSIONS FEES PAID BY U.S. REFINERIES
1994 THROUGH 2010
($1,000)

Year	Rate* ($PTPY)	VOC	NO_x	SO_2	CO	PM	Total
1994	36.25	9,976.1	9,833.7	12,045.7	4,466.5	1,653.9	37,975.9
1995	38.06	10,104.7	8,048.5	11,718.6	4,689.8	1,302.4	35,864.0
Total for 1994-1995		20,080.8	17,882.2	23,764.3	9,156.3	2,956.3	73,839.9
1996	39.97	10,236.7	6,508.1	11,426.3	4,924.3	1,025.7	34,121.0
1997	41.96	10,372.3	5,125.1	11,167.7	5,170.5	807.7	32,643.3
1998	44.06	10,606.4	4,036.0	10,941.8	5,429.0	636.1	31,649.4
1999	46.27	10,847.1	3,178.4	10,747.7	5,700.5	667.9	31,141.5
2000	48.58	11,094.4	3,003.6	10,584.7	5,985.5	701.3	31,369.5
Subtotal for 1996-2000		53,156.8	21,851.2	54,868.2	27,209.8	3,838.6	160,924.7
2001	51.01	11,460.8	2,838.4	10,648.8	6,273.9	736.3	31,958.2
2002	53.56	11,672.8	2,682.3	10,063.1	6,587.6	773.1	31,778.9
2003	56.24	11,888.7	2,534.7	9,509.6	6,917.0	811.8	31,661.9
2004	59.05	12,108.7	2,395.3	9,985.1	7,262.8	852.4	32,604.4
2005	62.00	12,332.7	2,263.6	10,484.4	7,626.0	895.0	33,601.6
2006	65.10	12,560.8	2,139.1	11,008.6	8,007.3	939.8	34,655.6
2007	68.35	12,793.2	2,021.4	11,559.0	8,407.6	986.8	35,768.1
2008	71.77	13,432.9	2,122.5	12,137.0	8,828.0	1,036.1	37,556.5
2009	75.36	14,104.5	2,228.6	12,743.8	9,269.4	1,087.9	39,434.3
2010	79.13	14,809.7	2,340.1	13,381.0	9,732.9	1,142.3	41,406.0
Subtotal for 2001-2010		127,164.8	23,566.0	111,520.6	78,912.7	9,261.5	350,425.5
Total for period 1996-2010		180,321.6	45,417.3	166,388.8	106,122.4	13,100.1	511,350.2

Initial rate for 1994 is an Average Weighted Rate for U.S., assuming $100 per ton for all sources in California and $25 for remainder of U.S. Rates for Subsequent Years are escalated by 5%.

Note: Due to rounding, columns and rows may not add.

Table 3-11

EMISSIONS FEES NATIONWIDE BY REFINERY-SIZE GROUP
($1,000)

Refinery Grouping	a	b	c	d	e	f	g	h	i	Total
1994	120.9	801.0	2,231.3	5,343.7	3,597.0	6,594.7	4,596.2	6,897.4	7,791.6	37,975.9
1995	114.2	758.3	2,107.3	5,046.6	3,397.0	6,228.0	4,340.6	6,513.8	7,358.3	35,864.0
Total for 1994-1995	235.1	1,561.3	4,338.6	10,390.3	6,994.0	12,822.8	8,936.7	13,411.1	15,150.0	73,839.9
1996	108.6	721.5	2,004.8	4,801.3	3,231.9	5,925.3	4,129.6	6,197.2	7,000.7	34,121.0
1997	103.9	690.2	1,918.0	4,598.4	3,091.9	5,668.7	3,950.8	5,928.8	6,697.5	32,643.3
1998	100.8	669.2	1,859.6	4,453.5	2,997.8	5,496.1	3,830.5	5,748.3	6,493.6	31,649.4
1999	99.1	658.5	1,829.8	4,382.0	2,949.7	5,407.9	3,769.0	5,656.1	6,389.4	31,141.5
2000	99.9	663.3	1,843.2	4,414.1	2,971.3	5,447.5	3,796.6	5,697.5	6,436.2	31,369.5
Subtotal for 1996-2000	512.3	3,402.7	9,455.4	22,644.3	15,242.5	27,945.6	19,476.5	29,227.9	33,017.5	160,924.7
2001	101.7	675.7	1,877.8	496.9	3,027.0	5,549.7	3,867.9	5,804.4	6,557.0	31,958.2
2002	101.2	672.0	1,867.2	4,471.7	3,010.0	5,518.6	3,846.2	5,771.8	6,520.2	31,778.9
2003	100.8	669.5	1,860.3	4,455.3	2,999.0	5,498.3	3,832.0	5,750.6	6,496.2	31,661.9
2004	103.8	689.4	1,915.7	4,587.9	3,088.2	5,662.0	3,946.1	5,921.8	6,689.5	32,604.4
2005	107.0	710.5	1,974.3	4,728.2	3,182.7	5,835.1	4,066.8	6,102.9	6,894.2	33,601.6
2006	110.3	732.8	2,036.2	4,876.5	3,282.5	6,018.2	4,194.3	6,294.3	7,110.4	34,655.6
2007	113.9	756.3	2,101.6	5,033.0	3,387.9	6,211.4	4,329.0	6,496.4	7,338.7	35,768.1
2008	119.6	794.1	2,206.7	5,284.7	3,557.3	6,521.9	4,545.4	6,821.2	7,705.6	37,556.5
2009	125.6	833.8	2,317.0	5,548.9	3,735.2	6,848.0	4,772.7	7,162.2	8,090.9	39,434.3
2010	131.8	875.5	2,432.9	5,826.4	3,921.9	7,190.4	5,011.3	7,520.4	8,495.4	41,406.0
Subtotal for 2001-2010	1,115.7	7,409.7	20,589.8	49,309.6	33,191.7	60,853.6	42,411.5	63,645.9	71,898.0	350,425.5
Total for period 1996-2010	1,628.0	10,812.4	30,045.2	71,953.8	48,434.2	88,799.2	61,888.0	92,873.8	104,915.5	511,350.2

NOTE: Due to rounding, columns and rows may not add.

Table 3-12 presents the details on what air control technologies and programs investments are being spent on and the time periods being covered. The majority of the total $7,501 million is estimated to be spent in the 1991 through 1995 time frame as indicated by the data listed below:

Period	$ Million	Percent
1991-1995	3,537	47.1
1996-2000	1,874	25.0
2001-2010	2,090	27.9

The major control technologies in which investments will be made are for VOC and PM-10. Although spending for SO_x reduction appears to be small, it is due to the majority of medium - large refineries that have already installed SRUs and sulfur tail gas recovery units.

Also, spending for NO_x reduction may appear to be low. NO_x reduction is being planned for the use of ultra-low NO_x burners rather than SCRs on large process heaters (over 100 million Btu/hour) except in severe and extreme ozone nonattainment areas. Also, insufficient information was available to determine NO_x control systems on refinery steam/power generation systems.

Capital investments for air control technology per refinery per group are presented in Table 3-13 and illustrated in Figure 3-6. Capital investment is dominated in 1991 through 1995 for refineries in all but Group g. The requirement to install SCRs on process heaters and FCCs units for Groups g and i refineries sited in severe ozone nonattainment cause high investment in the 2001 through 2010 time frame.

Table 3-12

AIR CONTROL TECHNOLOGY COSTS
INCREMENTAL CAPITAL INVESTMENT
ALL REFINERY GROUPS
($ MILLION)

	Implementation Period			
	91-95	96-00	01-10	Total
PM Control				
Redundancy	0	222	445	667
New Units	293	293	0	586
Sub-total	293	516	445	1,253
SO_x Control				
SRU + TGU (Attain)				
Redundancy	0	161	323	484
New Units	47	263	103	414
SRU + TGU (Non-Attain)				
Redundancy	0	12	24	37
New Units	9	15	8	32
Subtotal	56	452	458	966
NO_x Control				
Burners <100 10^6 Btu/hr.				
Serious & Less	0	7	7	15
Severe	2	5	0	7
Extreme	2	2	0	4
Burners >100 10^6 Btu/hr.				
Serious & Less	0	30	30	60
Severe	11	32	0	42
Extreme	0	0	0	0
Heaters - SCR				
Severe	0	0	476	476
Extreme	69	69	0	138

Table 3-12 (Cont'd)

AIR CONTROL TECHNOLOGY COSTS
INCREMENTAL CAPITAL INVESTMENT
ALL REFINERY GROUPS
($ MILLION)

	Implementation Period			
	91-95	96-00	01-10	Total
FCC - SCR				
Severe	0	0	146	146
Extreme	0	26	9	34
Subtotal	83	170	667	921
Fugitives				
Pumps	1,022	0	0	1,022
Valves	1,570	0	0	1,570
Compressors	30	10	0	40
Enhanced I&M	0	0	0	0
Subtotal	2,621	10	0	2,631
Pressure Relief Valves	15	30	0	45
Storage Tanks				
Crude Oil	72	214	0	286
Light Hydrocarbons	0	0	299	299
Subtotal	72	214	299	585
Coker Vents	40	119	0	159
Coker Handling	94	94	187	374
Waste Treatment System Covers				
Primary Separation	136	136	0	272
Activated Sludge	17	17	34	68
Subtotal	153	153	34	340
Waste Handling System	108	108	0	216
Permits and Fees	0	0	0	0
Switch to Clean Fuel	3	9	0	12
Total All Refinery Groups Incremental Capital Investment	3,537	1,874	2,090	7,501

Note: Columns and rows may not add due to rounding.

Table 3-13

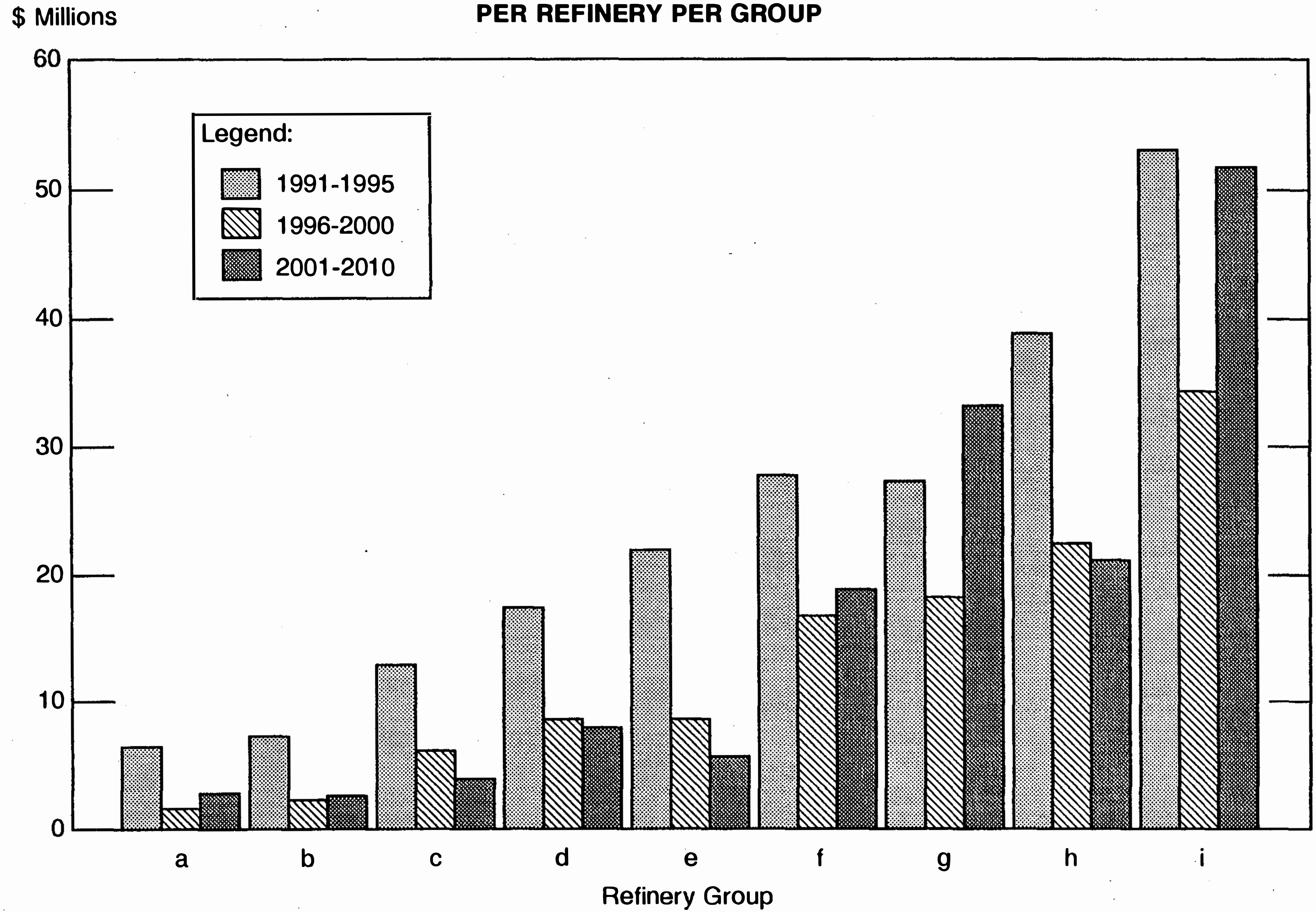
CAPITAL INVESTMENT FOR AIR CONTROL TECHNOLOGIES PER REFINERY PER GROUP ($ MILLION)

Group	No. of Refineries Per Group	Capital Investment Per Group	Capital Investment Per Refinery 1991-1995	1996-2000	2001-2010	Total
a	26	262	6	2	2	10
b	24	288	7	2	3	12
c	40	919	13	6	4	23
d	28	946	17	8	8	33
e	12	432	22	8	6	36
f	24	1,520	27	17	18	63
g	11	865	27	18	34	79
h	14	1,154	39	22	21	82
i	8	1,115	53	34	52	139
Total	187	7,501	--	--	--	--

Note: Columns and rows may not add due to rounding.

Figure 3-6

CAPITAL INVESTMENT FOR AIR CONTROL TECHNOLOGIES PER REFINERY PER GROUP



1092001-2

3.4.2 Incremental One-Time Costs

The estimated incremental one-time costs for control systems and programs for reducing air emissions by the U.S. refining industry during the 1991 through 2010 period is $38 million (mid-1990 U.S. Gulf Coast). The one-time costs are for two programs:

- Enhanced inspection and maintenance
- Switching to clean fuel, natural gas replacing No. 6 fuel oil as a refinery fuel

Table 3-14 presents the details on what air control technologies the one-time costs are estimated. One-time cost for air control technologies per refinery per group are presented in Table 3-15. The costs are rather minor for a refinery since the costs only cover two programs.

3.4.3 Incremental Operating and Maintenance (O&M) Expenses

The estimated incremental O&M expenses for the air emission control devices and programs for the three time periods are:

Year	$ Million
1995	228
2000	454
2010	152

Table 3-16 presents the details on what air emission control devices and programs are covered by these O&M expenses. Several control systems and programs that contribute to a major share of the O&M expenses are:

- Switching to clean fuel, natural gas replacing No. 6 fuel oil as a refinery fuel
- Conducting enhanced inspection and maintenance programs
- Operating redundant and new SRUs and tail gas sulfur recovery units

3.5 Sensitivity Analysis

3.5.1 Pressure Relief Valves

The basis used for costing this element in the study assumes that emissions will be collected from PRVs currently vented to the atmosphere. In the event that regulatory agencies require emissions to be collected from not only PRVs, but also crude column vents and main fractionator vents on downstream processing units, the stream of VOC to be managed will be much greater. Additional header capacity will be required to collect vents from the larger number of columns. Headers will be larger, and multiple header systems will be required for refineries in Groups f, h, and i. Responses from the NPC Survey provided guidance on the number of refineries in a group and the number of large columns being vented to the atmosphere. Also, new larger and taller flare systems will be required to combust the large amounts of collected vapors.

Table 3-14

AIR CONTROL TECHNOLOGY COSTS
INCREMENTAL ONE-TIME COST
ALL REFINERY GROUPS
($ MILLION)

	Implementation Period			
	91-95	96-00	01-10	Total
PM Control				
Redundancy	0	0	0	0
New Units	0	0	0	0
Subtotal	0	0	0	0
SO_x Control				
SRU + TGU (Attain				
Redundance	0	0	0	0
New Units	0	0	0	0
SRU + TGU (Non-Attain)				
Redundancy	0	0	0	0
New Units	0	0	0	0
Subtotal	0	0	0	0
NO_x Control				
Burners <100 10^6 Btu/Hr.				
Serious & Less	0	0	0	0
Severe	0	0	0	0
Extreme	0	0	0	0
Burners >100 10^6/Hr.				
Serious & Less	0	0	0	0
Severe	0	0	0	0
Extreme	0	0	0	0
Heaters - SCR				
Severe	0	0	0	0
Extreme	0	0	0	0

Table 3-14 (Cont'd)

AIR CONTROL TECHNOLOGY COSTS
INCREMENTAL ONE-TIME COST
ALL REFINERY GROUPS
($ MILLION)

	Implementation Period			
	91-95	96-00	01-10	Total
FCC - SCR				
Severe	0	0	0	0
Extreme	0	0	0	0
Subtotal	0	0	0	0
Fugitives				
Pumps	0	0	0	0
Valves	0	0	0	0
Compressors	0	0	0	0
Enhanced I&M	8	24	0	32
Subtotal	8	24	0	32
Pressure Relief Valves	0	0	0	0
Storage Tanks				
Crude Oil	0	0	0	0
Light Hydrocarbons	0	0	0	0
Subtotal	0	0	0	0
Coker Vents	0	0	0	0
Coke Handling	0	0	0	0
Waste Treatment System Covers				
Primary Separation	0	0	0	0
Activated Sludge	0	0	0	0
Subtotal	0	0	0	0
Waste Handling System	0	0	0	0
Permits and Fees	0	0	0	0
Switch to Clean Fuel	1	4	0	6
Total All Refinery Groups Incremental One-Time Cost	10	29	0	38

Note: Columns and rows may not add up due to rounding.

Table 3-15

ONE-TIME COSTS FOR AIR CONTROL TECHNOLOGIES PER REFINERIES PER GROUP ($ MILLION)

Group	No. of Refineries Per Group	One-time Costs Per Group	One-time Costs Per Refinery
a	26	2	<1
b	24	2	<1
c	40	7	<1
d	28	5	<1
e	12	3	<1
f	24	7	<1
g	11	3	<1
h	14	5	<1
i	8	4	<1
Total	187	38	--

Table 3-16

AIR CONTROL TECHNOLOGY COSTS
INCREMENTAL O&M COSTS
ALL REFINERY GROUPS
($ MILLION/YEAR)

	Implementation Period		
	1995	2000	2010
PM Control			
Redundancy	0	8	16
New Units	23	23	0
Subtotal	23	31	16
SO_x			
SRU + TGU (Attain)			
Redundancy	0	16	24
New Units	8	36	15
SRU + TGU (Non-Attain)			
Redundancy	0	3	6
New Units	0	2	2
Subtotal	8	57	47
NO_x Control			
Burners<100 10^6 Btu/Hr.			
Serious & Less	0	< 1	< 1
Severe	< 1	< 1	0
Extreme	< 1	< 1	0
Burners <100 10^6 Btu/Hr.			
Serious & Less	0	2	2
Severe	< 1	2	0
Extreme	0	0	0
Heaters - SCR			
Severe	0	0	38
Extreme	5	5	0

Table 3-16 (Cont'd)

AIR CONTROL TECHNOLOGY COSTS
INCREMENTAL O&M COSTS
ALL REFINERY GROUPS
($ MILLION/YEAR)

	Implementation Period		
	1995	2000	2010
FCC - SCR			
Severe	0	0	15
Extreme	0	3	1
Subtotal	6	14	57
Fugitives			
Pumps	0	0	0
Valves	0	0	0
Compressors	0	0	0
Enhanced I&M	16	49	0
Subtotal	16	49	0
Pressure Relief Valves	24	48	0
Storage Tanks			
Crude Oil	2	6	0
Light Hydrocarbons	0	0	7
Subtotal	2	6	7
Coker Vents	3	8	0
Coke Handling	11	11	23
Waste Treatment System Covers			
Primary Separation	18	18	0
Activated Sludge	1	1	2
Subtotal	19	19	2
Waste Handling System	6	6	0
Permits and Fees	43	0	0
Switch to Clean Fuel	69	207	0
Total All Refinery Groups Incremental O&M Costs	228	454	152

Note: Columns and rows may not add due to rounding.

The incremental capital investment of installing new systems for collecting VOC from the additional PRV vents and flaring them will be an estimated $720 million. The estimated incremental capital investments for the larger flare systems to gather emissions from PRVs are presented in Table 3-17, and are illustrated in Figure 3-8. As indicted from responses on the NPC survey, refineries in Groups f, h, and i would incur major investment to install new relief header and flare systems for collecting VOC from PRVs, crude column vents, and main fractionator vents on down stream processing units.

Table 3-17

INCREMENTAL INVESTMENT FOR RELIEF HEADER AND FLARE SYSTEMS ($ MILLION)

Grouping	No. of Refineries	Base Case	Case A
a	26	4	< 1
b	24	4	< 1
c	40	7	1
d	28	6	5
e	12	4	2
f	24	10	164
g	11	6	13
h	14	10	254
i	8	10	280
Total	187	60	720

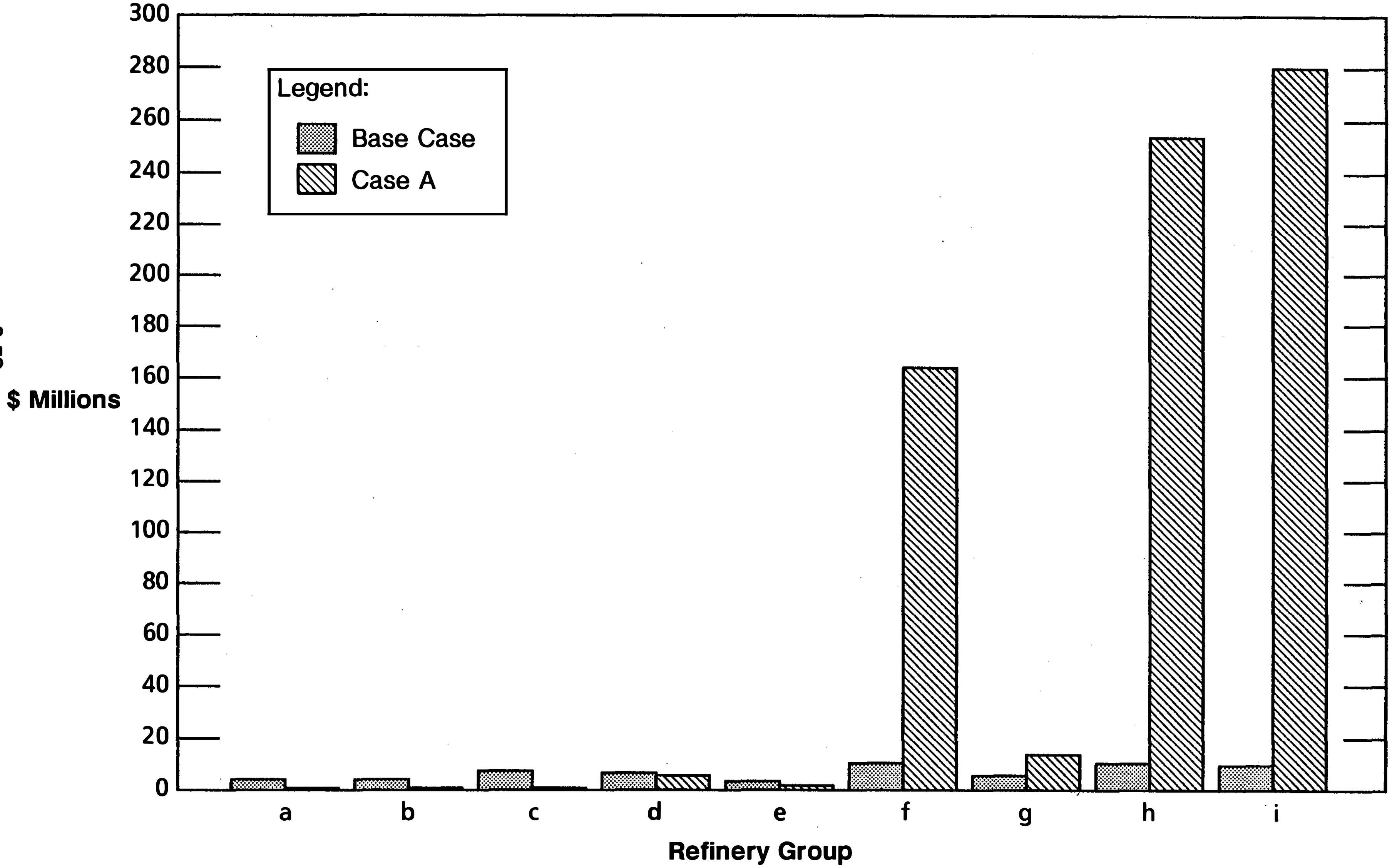
Base Case: Header-flare system is sized to handle PRVs that are vented to atmosphere.

Case A: Header-flare system is sized to handle PRVs, crude column vents, and main fractionator vents on down stream processing units.

Note: Columns may not add due to rounding.

Figure 3-7

INCREMENTAL INVESTMENT FOR
RELIEF HEADER AND FLARE SYSTEMS



1092001-2

4.0 WASTEWATER SECTOR

4.0 WASTEWATER SECTOR

Refinery wastewater programs being implemented during the 1990s and the first decade of the 21st century are a product of EPA's Clean Water Act (CWA) Reauthorization of 1990.

The incremental cost estimates for the U.S. refining industry to meet the NPC's premises of CWA are as follows:

	$ Million						
Item	**1991-1995**	**1995**	**1996-2000**	**2000**	**2001-2010**	**2010**	**Total**
Capital Investment	1,251	---	4,478	---	6,602	---	12,331
One-Time Costs	---	---	---	---	8	---	8
Total	1,251	---	4,478	---	6,610	---	12,339
O&M Expenses	---	44	---	405	---	573	---

Note: Costs are expressed in mid-1990 U. S. Gulf Coast dollars.

4.1 Premises

The NPC's premises upon which estimated wastewater control systems and their associated investments are based have been developed from existing and anticipated wastewater regulations. NPC's premises are presented in Table 4-1 and include the implementation schedule from 1991 through 2010.

4.2 Clean Water Act Reauthorization

The reauthorization of the comprehensive CWA includes the following group of requirements.

4.2.1 Reduction of Wastewater Toxicity and Biomonitoring

This premise identifies perhaps the overriding concern in meeting the requirements of most recently-issued and future National Pollutant Discharge Elimination System (NPDES) permits: reducing effluent toxicity sufficiently to meet the acute-toxicity and chronic-toxicity biomonitoring standards for invertebrate and vertebrate species which are included in those permits.

4.2.2 Elimination of Chromium Compounds from Cooling Towers

Most U.S. refineries have already implemented provisions to comply with this premise. Substitute compounds are readily available. Therefore, this premise will not have either capital investment or O&M expenses developed for compliance.

Table 4-1

WASTEWATER TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject	Limit/Scope	Technology	Percent Implementation During 1991 - 1995	1996 - 2000	2001 - 2010
CWA REAUTHORIZATION Process Wastewater Reuse	Max. practical reuse of process wastewater	Use effluent as cooling tower makeup. Sidestream-treat to minimize BD.	0	0	50
New BAT Mandated	Assume maximum organic/metals removal	Filtration of ASP/PACT Treatment. Two-stage activated sludge (ASP). Powdered activated carbon (PACT). Target heavy metal precipitation.	Capital, O&M, and O.T. Costs included in biomonitoring		
Water Quality Based NPDES Permits	Reduce toxicity of effluent (biomonitoring)	Filtration of ASP/PACT Treatment. Two-stage activated sludge (ASP). Powdered activated carbon (PACT). Target heavy metal precipitation.	0	50	50
	Reduce oil to sewer, storm water contamination	Exclude storage tanks drawoffs from storm sewers. Hard pipe tank drawoff to segregated sewer system.	Capital, O&M, and O.T. Costs included in Groundwater		
	Reduce oil to sewer, storm water contamination	Exclude hydrocarbon samples from storm sewers. Install closed loop samplers.	25	50	25
	Reduce storm water contamination	Intercept process unit pad drains. Build segregated process pad drainage lift stations.	75	25	0

Table 4-1 (Cont'd)

WASTEWATER TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject	Limit/Scope	Technology	Percent Implementation During		
			1991 - 1995	1996 - 2000	2001 - 2010
Water Quality Based NPDES Permits (cont'd)	Reduce runoff from unpaved process areas	Pave non-pad process areas to reduce TSS	75	25	0
	Reduced discharge of suspended solids	Filtration of ASP/PACT Effluent Pave non-pad process areas to reduce TSS	75	25	0
		Route runoff to same segregated lift stations	75	25	0
Sediments Criteria	Sediments discharged from WWTP	Develop estimate to quantify and remediate areas where sedimentation has occurred.	0	0	25
STORMWATER QUALITY	Store and treat quantity of contaminated storm water from 10-year storm	Intercept process unit pad drains. Build segregated process pad drainage lift stations. Store and treat all stormwater runoff from process unit pads. Route runoff to same segregated lift stations.	25	25	50
GROUNDWATER ISSUES Pollution Prevention - Tanks	Prevent groundwater pollution from storage tanks	Retrofit all storage tanks (not now covered by RCRA) with double bottoms.	25	25	50
	Prevent groundwater pollution from storage tanks	Install membrane liners and crushed stone inside tank farm diked areas. Route runoff to same segregated lift stations provided for tank drawoffs.	0	0	25
Pollution Prevention - Process Piping	Prevent groundwater contamination from underground process piping	Daylight (expose) below grade process piping, leak detection. Use survey data to quantify underground piping to be modified.	25	25	50

Table 4-1 (Cont'd)

WASTEWATER TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject	Limit/Scope	Technology	Percent Implementation During		
			1991 - 1995	1996 - 2000	2001 - 2010
Pollution Prevention - Process Piping (cont'd)	Prevent groundwater contamination from underground process sewers	Hard pipe tank drawoff to segregated sewer system.	25	25	50

4.2.3 Storm Water Permit Requirement to Exclude Oil (in Storm Water) from Tank Drawoffs

This compliance premise anticipates that future storm water regulations will require elimination of storage tank drawoffs from storage tank diked areas and from sewers, catch basins, and lift stations where drawoffs from tanks could commingle with storm water.

4.2.4 Storm Water Permit Requirement to Exclude Oil from Sampling (in Storm Water)

This compliance premise anticipates that future storm water regulations will not allow hydrocarbon process sample purging and draining to sewers, catch basins, and lift stations where those samples could commingle with storm water.

4.2.5 Storm Water Permit Requirement to Exclude Exchanger Cleaning Wastes (from Storm Water)

This compliance premise anticipates that process hydrocarbon wastes and associated chemical wastes which result from periodic cleaning of heat exchangers (and other process equipment) must not be drained to sewers, catch basins, and lift stations where those wastes could commingle with storm water.

4.2.6 Storm Water Permit Requirement to Reduce Runoff from Unpaved Process Areas (Which is Discharged as Storm Water)

This compliance premise anticipates that runoff from "process areas" must be minimized or eliminated from discharge through outfalls permitted for storm water only.

4.2.7 Storm Water Permit Requirement to Reduce Discharge of Suspended Solids (in Storm Water)

This compliance premise anticipates that future regulations will significantly reduce the allowable concentrations or absolute quantities of suspended solids in runoff discharged through outfalls permitted for storm water only.

4.2.8 Store and Treat Quantity of Contaminated Storm Water from 10-Year Storm

This compliance premise anticipates that future regulations will require that the quantity of contaminated storm water (from a storm of an intensity and duration that occurs no more frequently than every 10 years) cannot be released through an outfall designated for storm water only. The designation of that storm water as contaminated or potentially contaminated would be determined by where the storm water fell. Presumably, this quantity of storm water would have to be stored and treated to meet the same criteria applicable to process wastewater.

4.3 Anticipated Regulations Applicable to Water and Wastewater

The following wastewater requirements are anticipated in addition to CWA reauthorization.

4.3.1 Anticipated Requirement for Process Wastewater Reuse

This premise assumes that future regulations will require that refineries treat and reuse a substantial amount of their process wastewater to reduce the fresh water demand by refineries.

For the purposes of this study and cost estimate, the reuse of process wastewater would be accomplished in three steps:

- Addition of filtration after the two-stage activated sludge biological treatment powdered activated carbon; note that this filtration would also be required to satisfy anticipated requirement to minimize discharge of suspended solids. Installation of tertiary-treatment filters is anticipated in 75 percent of all refineries by 2000, 100 percent by 2010.

- Reclaimed process wastewater that had received tertiary treatment would be used as cooling tower makeup. Use of tertiary-treated process wastewater for cooling tower makeup would be anticipated in 75 percent of refineries by 2000 and in 100 percent by 2010; because once the filters were installed, minimal additional equipment would be required to utilize the reclaimed water as cooling tower makeup.

- The next stage of reclaimed process wastewater reuse would be to install sidestream softeners and filters treating cooling tower blowdown. These systems control the concentrations of silica and "hardness" salts whose solubilities limit the cycles of concentration in the cooling tower and associated heat-transfer equipment. Installation of cooling-tower sidestream treatment systems is anticipated in 50 percent of all refineries by 2010.

Reverse osmosis or electrodialysis are the presently available, commercially demonstrated technologies for total dissolved solids removal that would be used to further treat cooling tower recirculating water or treat process wastewater for steam cycle makeup. These technologies would also be used in conjunction with waste evaporators to achieve a "100 percent re-use" or "zero discharge" operation. Because of the high cost of such systems, which have extensive pretreatment requirements, it is not anticipated that these technologies would be widely installed by 2010; and, therefore, they are not included in the model refinery.

4.3.2 Mandated Application of Best Available Technology (New BAT Mandated)

This premise assumes that future regulations will require that refineries treat their process wastewater with the BAT to minimize its toxicity and the amount of organics discharged. This premise is reflected in the selection of all of the control technologies and provisions; based on well-demonstrated, commercially-available technology.

High-organic-content waste streams that occur in significant quantities from process equipment usually have benzene concentrations greater than 10 mg/l. Experience to date with high-organic-content waste streams from tank water drawoffs indicates that those streams also usually contain greater than 10 mg/l benzene. These streams are subject to NESHAP regulations. Prior to the 1995 schedule threshold for this study, these streams will be handled in sealed, vent-controlled sumps, routed to aboveground hard piping, and treated in benzene removal units.

However, heavy and other toxic metals can contribute significantly to effluent toxicity. The highest concentrations of such metals typically occur in desalter water effluent and in wastewater from coker operations. High concentrations can also occur in softener or demineralizer regenerant, but in much smaller absolute quantities.

4.3.3 Anticipated Requirements to Assess and Remediate Sediments in Outfall Areas

This premise assumes that future regulations will require that refineries determine whether bodies of water that have received their effluent in the past have had sediments from those effluents deposited within those bodies; the nature and effects of those sediments; and the extent of such affected areas. The premise further assumes that refineries will have to remediate such areas where sedimentation has negatively affected effluent-receiving bodies.

4.4 Anticipated Regulations Applicable to Groundwater Issues

The following regulatory requirements which pertain to prevention of groundwater pollution are projected to become effective during the period covered by the study.

4.4.1 Prevent Groundwater Pollution from Potentially Defective Storage Tanks

This anticipated regulation would require that existing light and heavy hydrocarbon storage tanks (not only those that contain "listed" wastes that are covered by existing RCRA and other regulations) would have to be retrofitted or reconstructed to provide a higher degree of containment integrity.

4.4.2 Prevent Groundwater Pollution from Storage Tank Areas

This anticipated regulation would require that containment areas, such as diked enclosures, around existing light and heavy hydrocarbon storage tanks (not only those that contain "listed" wastes that are covered by existing RCRA and other regulations) would have to be retrofitted to prevent any spills or ruptures from contacting the earth; as such spills could potentially contaminate groundwater.

4.4.3 Prevent Groundwater Pollution from Underground Process Piping

This anticipated regulation would require that underground piping which contains hydrocarbons (not only piping that contain "listed" wastes which is covered by existing RCRA and other regulations) would have to be modified to minimize the potential for groundwater contamination from any piping disruptions.

4.4.4 Prevent Groundwater Pollution from Underground Process Sewers

This anticipated regulation would require that underground process sewers which could contain significant concentrations of hydrocarbons (not only sewers that contain specific wastes which are covered by other existing regulations) would have to be modified to minimize the potential for contamination of groundwater from any disruptions of those sewers and associated structures.

4.5 Control Technologies

This section describes the control technologies and other programs which have been identified as the most practical and cost-effective ways to establish compliance with the premises previously discussed.

The overall program to reduced storm water contamination, or storm water and process wastewater segregation, is based on exclusion of all process units dry-weather wastewater flow and the rainfall on process unit pad areas from all other storm water.

4.5.1 Filtration of Activated Sludge (ASP)/Powdered Activated Carbon (PACT) Effluent

The control technology would be the addition of a continuous-backwash type gravity filtration system after the two-stage activated sludge biological treatment powdered activated carbon treatment. This filtration step would be necessary to satisfy BAT requirements and would be essential in treating process wastewater for re-use. It has been demonstrated to be effective in large-scale municipal and industrial applications; and it has been demonstrated to meet State of California Title 22 requirements for re-use of treated wastewater.

4.5.2 Two-Stage ASP/PACT

The group refinery design includes two-stage activated-sludge biological treatment with powdered activated carbon addition (ASP/PACT). This system has been demonstrated to be most likely to meet the bio-monitoring requirements that presumably will be incorporated into virtually all NPDES permits for discharge of treated process wastewater.

The group refinery basis of estimate design would be based on the assumption that the entire ASP/PACT system would be built in above-ground steel tankage; and would be sized to treat the entire process wastewater treatment flow on a continuous basis and to treat a workoff stream of the stored storm water which falls on paved process unit pad areas.

The group refinery is based on the addition of all new ASP/PACT facilities because the refineries surveyed are presently performing such widely different degrees of biological treatment; and much of that in earthen impoundments. Assuming the addition of new ASP/PACT installations to all refineries provides a conservative basis of total capital investment requirements.

The economics of regenerating the PAC vary widely from location to location; depending on the amount of PAC required, the prevailing local air quality requirements, and the many different PAC regeneration technologies. For this reason, PAC consumption will be developed as an O&M expense, rather than a capital investment.

4.5.3 Alternative Internal Treatment Chemicals in Cooling Towers

As previously discussed, this will not be reflected as either a capital investment or as an O&M expense as most U.S. refineries have already implemented provisions to comply with this premise. Substitute compounds for corrosion inhibition (replacing chromium compounds) and microbiological control (replacing chlorine) are readily available.

4.5.4 Hard-Pipe Tank Drawoff to Segregated Sewer System

A refinery would incorporate drawoff collection and lift stations located near the tank farm areas. The lift stations would have sealed covers and vent controls. Tank drawoffs would be hard-piped to these lift stations. The discharge from the lift stations would be hard-piped to the wastewater treatment plant storage and equalization tanks (as previously discussed). This tank drawoff waste stream would thus be handled in the same way as the waste stream from process unit pad areas.

4.5.5 Install Closed Loop Samplers

Many closed-loop systems have already been installed to comply with NESHAP and OSHA regulations. As an example, in a 200,000 BPSD refinery, 40 closed-loop process samplers were installed out of a total of approximately 90 process sample points. This number of closed-loop systems were extrapolated to larger and smaller refineries to obtain representative quantities.

4.5.6 Intercept Process Unit Pad Drains; Build Segregated Process Pad Drainage Lift Stations

Dedicated process drainage systems would be established in the process unit pad areas by building lift stations that would intercept the existing sewers from the process unit pads, and pump the process unit pad drainage in above-ground piping to a floating-roof storage tank in the wastewater treatment plant.

4.5.7 Paved Non-Pad Process Areas to Reduce Total Suspended Solids (TSS) in Runoff

In determining the land requirement for a typical refinery in each of the nine refinery groups, the land required by the processing units was estimated as part of the overall parcel of land requirements. The estimated land area for the processing units is assumed to require some type of pave material. Collection of process and storm water falling on the paved material will be sent to the segregated process sewer system.

4.5.8 Store and Treat All Storm Water Runoff from Process Unit Pads

(Refer to the description under item 4.5.6)

In the event of a major storm, additional pumps in the lift stations would be activated. All of the flow from the process unit pad areas would be pumped to the floating-roof storage tank adjacent to the primary treatment equipment. There, the process units wastewater and the process unit pads storm water runoff would be stored in aboveground storage tanks for equalization and oil and solids removal.

The aboveground storage tanks would be sized to hold the entire volume of a ten-year storm event. The segregated process sewer lift stations would have pumping capacity to handle the maximum rainfall intensity (in terms of inches per hour) that would occur once every 25 years. The stored volume would be worked off through the rest of the primary treatment and biological treatment systems. The balance of the treatment system would be sized to work off the stored volume of the ten-year storm within one week.

4.5.9 Retrofit All Storage Tanks (Not Now Covered by RCRA) with Double Bottoms

The NPC Survey provided guidance on the total number and tankage capacity in light and heavy hydrocarbon service by refinery grouping. The survey also provided additional information on the tank bottom assembly-single or double bottoms. Estimated capital investment was developed for tanks requiring retrofitting for double bottoms.

4.5.10 Install Membrane Liners and Crushed Stone Inside Tank Farm Diked Areas

In determining the land requirement for a typical refinery in each of the nine refinery groups, the land required by the tank farm was estimated as part of the overall parcel of land requirements. Capital investments were developed for lining the tank farm areas with synthetic polymer membranes and gravel.

4.5.11 Replace Underground Process Piping

Responses from the NPC Survey data have been used to develop representative underground piping quantities for each refinery grouping. Unit costs were developed to remove the underground process piping and replace it with above-grade piping.

The new piping would be laid on sleepers at grade. The sleepers would be spaced at intervals along a lined concrete containment slab (with side walls). Any product spills would be collected in drain pipes spaced at suitable distances along the side of the slab. The piping runs would cross roads on elevated piperacks.

4.5.12 Primary and Biological Treatment Sludge to be Handled in Incinerator

All primary treatment solid oily wastes and biological treatment sludge would be handled in newly constructed incinerators. The incinerators considered for this service would most probably be a fluidized-bed type with recirculating water-spray stack gas scrubbing and the capability to incorporate heat recovery through steam generation.

An alternative for disposing of the primary treatment solid oily wastes and biological treatment sludge for refineries that have coking operations would be to route the waste materials to their cokers. There are reports that some refiners are already using this method for disposing of the primary treatment sludge oily wastes. Each refiner that has coking operations would need to evaluate this option of disposing of waste sludges versus installing an incinerator.

Sludge and solid waste handling facilities would incorporate RCRA requirements; such as above-ground construction of primary treatment equipment, double-wall tanks, and observable above-ground piping.

4.5.13 Excavate Outfall Area Sediments

The NPC Survey response data did not provide much basis for determining the numbers and types of receiving bodies that might require remediation for past sediment deposition.

The basis-of-estimate approach has been to assume that all refineries discharge to a quiescent body of surface water, such as a lake. A representative receiving-body depth has been established; along with an average discharge flow rate for each refinery group. From this information, an area that would have been significantly affected by sedimentation from the treated process wastewater outfall has been determined, and a unit cost per cubic yard of removal by dredging has been estimated.

For facilities which discharge to a river, it would be difficult to quantify what effects had resulted from sedimentation or to estimate a cost to remediate such effects; therefore, discharge to quiescent bodies has been postulated in all cases.

4.5.14 Cooling Tower Sidestream Softening, Clarification, and Filtration

One provision to facilitate re-use of treated process wastewater and minimize total refinery effluent would be to install sidestream softeners and filters treating cooling tower blowdown. In these control systems, the concentrations of suspended solids and silica and "hardness" salts whose solubilities limit the cycles of concentration in the cooling tower and associated heat-transfer equipment.

4.5.15 Coker Area Runoff and Wastewater Grit Removal System

It is assumed that refineries with delayed or fluid coking units will use water sprays to control fugitive dust emissions from around the coker process areas and coke storage building. The wastewater would be treated with a cylindrical in-ground grit removal chamber and solids dewatering equipment.

4.5.16 Coker Area Runoff and Wastewater Heavy Metal Precipitation System

Either of two systems could be used to remove heavy metals from coker wastewater. One of the alternative systems is a proprietary process and equipment system (UNOCAL "Unipure" system) that has a good operating history in treating heavy-metal containing waste streams. The other system is a conventional dual pH range precipitation process that uses lime, caustic, and sulfuric acid. As the installed and operating costs of the two systems are essentially similar, the conventional dual-range precipitation system has been used as the basis of estimated capital investment and O&M expenses, as it is not based on a proprietary system.

4.5.17 Process and Storm Water Collection, Storage, and Treatment Systems

Figure 4-1 illustrates several proposed process and storm water collection and storage systems that may be installed to minimize the quantity of contaminated water to be treated and maximize the quantity of uncontaminated storm water flowing to a permitted storm water outfall. The proposed treatment systems to handle contaminated process and storm water are illustrated in Figure 4-2.

4.6 Summary

4.6.1 Incremental Capital Investment

The estimated incremental capital investment for control systems and programs for processing wastewater and reducing groundwater pollution by the U.S. refining industry during the 1991 through 2010 period is $12,331 million (mid-1990 U.S. Gulf Coast). The investment will be spread over three areas as indicated below:

Item	$ Million	Percent
CWA Reauthorization	7,587	61.5
Storm Water Quality	1,196	9.7
Groundwater Issues	3,548	28.8

Table 4-2 details the wastewater control technologies, the investments being made, and the time periods being covered. The majority of the $12,331 million is estimated to be spent in the 2001 through 2010 time frame as indicated by the data listed below:

Period	$ Million	Percent
1991-1995	1,251	10.1
1996-2000	4,478	36.3
2001-2010	6,602	53.6

The major area of wastewater investment will be made to reduce and control the toxicity of refinery wastewater effluent during 1996 through 2010 time frame.

Figure 4-1

PROCESS AND STORM WATER COLLECTION AND STORAGE SYSTEMS

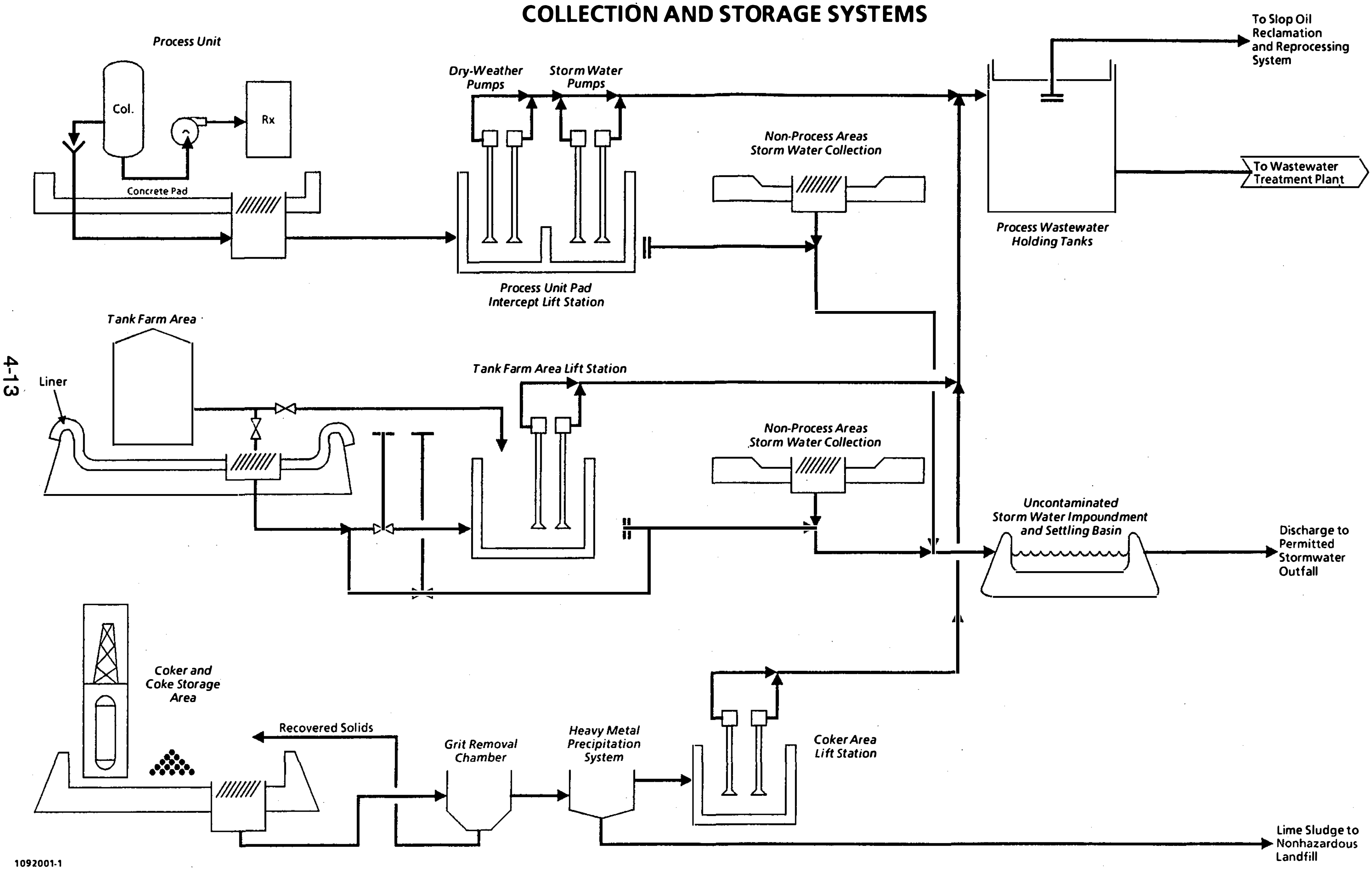
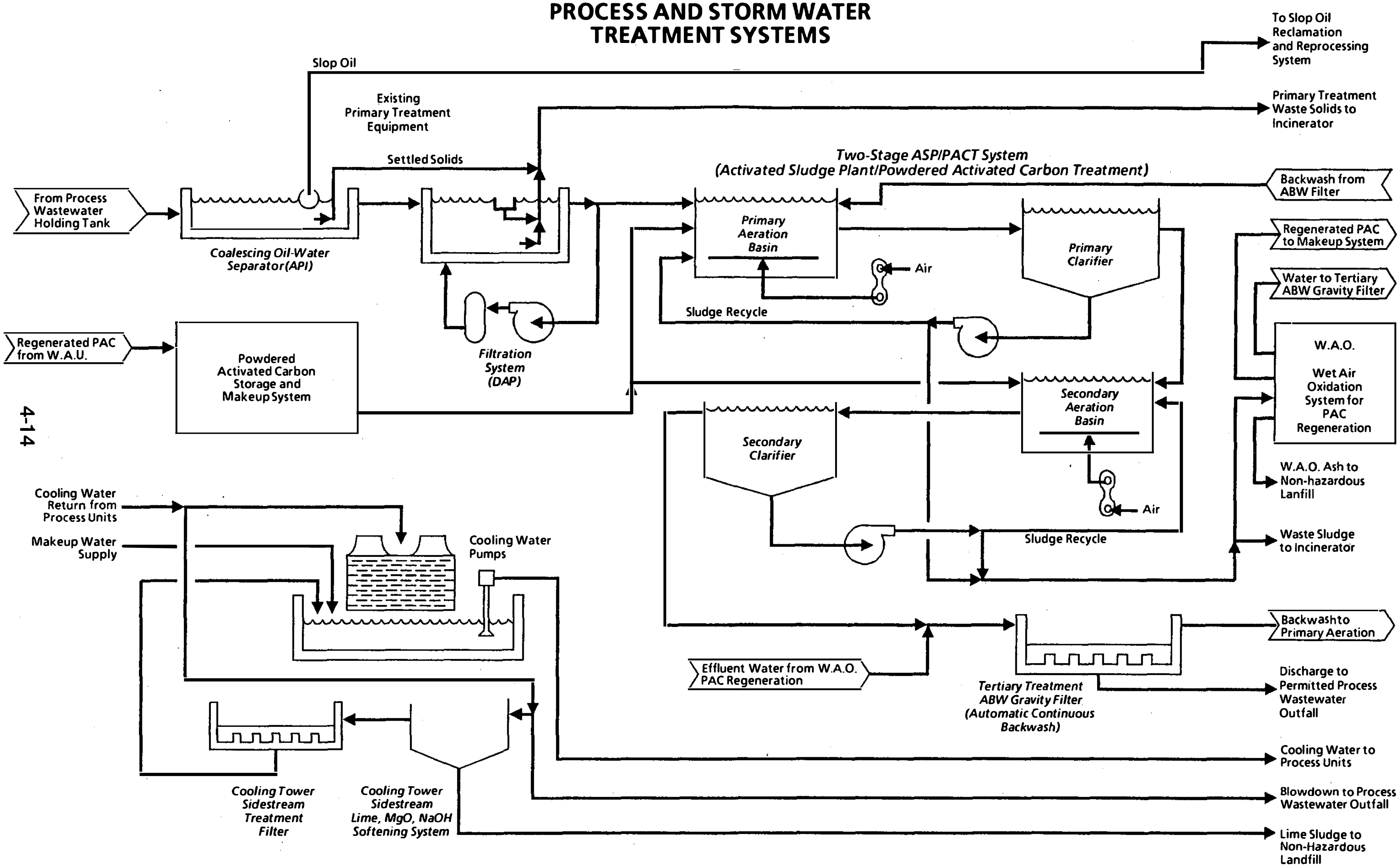


Figure 4-2

PROCESS AND STORM WATER TREATMENT SYSTEMS



1092001-1

Table 4-2

WASTEWATER TECHNOLOGY COSTS
INCREMENTAL CAPITAL INVESTMENT
ALL REFINERY GROUPS
($ MILLION)

	Implementation Period			
	91-95	96-00	01-10	Total
CWA REAUTHORIZATION				
Max. Practical Reuse of Process Wastewater	0	0	804	804
Reduce Toxicity of Effluent (Biomonitoring)				
Filtration of ASP/PACT Treatment	0	501	501	1,001
Two-stage Activated Sludge (ASP) and Powdered Activated Carbon (PACT)	0	1,554	1,554	3,107
Incineration of Sludge	0	1,155	1,155	2,310
Target Heavy Metal Precipitation	0	86	86	173
Subtotal, Reduce Toxicity	0	3,296	3,296	6,591
Reduce Oil to Sewer, Closed Loop Sampler	9	19	9	38
Reduce Runoff from Unpaved Process Area	116	39	0	154
Sediments Discharged from WWTP	0	0	0	0
Subtotal, CWA REAUTHORIZATION	125	3,353	4,109	7,587
STORM WATER QUALITY				
Store and Treat Quantity of Contaminated Process Water and Storm Water from 10-year Storm				
Build Lift Stations	13	13	26	53
Store and Treat Storm Water Runoff	287	286	572	1,144
Subtotal, STORM WATER QUALITY	299	299	598	1,196
GROUNDWATER ISSUES				
Retrofit All Storage Tanks - Double Bottoms	512	512	1,023	2,046
Install Membrane Liners	0	0	242	242
Subtotal	512	512	1,265	2,288
Raise or Replace Below Grade Process Piping	234	234	469	937
Hard Pipe Tank Drawoff	81	81	162	323
Subtotal	315	315	630	1,260
Subtotal, GROUNDWATER ISSUES	827	827	1,895	3,548
All Refinery Groups Incremental Capital Investment	1,251	4,479	6,602	12,331

Note: Columns and rows may not add due to rounding.

Capital investments for wastewater control technologies per refinery per group are presented in Table 4-3 and illustrated in Figure 4-3. The majority of capital investment will be made in the 2001 through 2010 period by refineries in all refinery groups. The major capital spending items are for the reduction of toxicity in refinery wastewater streams and to retrofit light and heavy hydrocarbon storage tankage with double bottoms.

4.6.2 Incremental One-Time Costs

The estimated incremental one-time costs for control systems and programs for processing wastewater and reducing ground pollution by the U.S. refining industry during the 1991 through 2010 period is only $8 million (mid-1990 U.S. Gulf Coast). This one-time cost is for a program to remove sediment discharge into a quiescent body of surface water, such as a lake. The implementation schedule for this program is to incur 25 percent in period 2001 through 2010 and 75 percent after 2010. Table 4-4 presents the details on what wastewater control technologies the one-time costs are made by refinery group.

4.6.3 Incremental Operating and Maintenance (O&M) Expenses

The estimated incremental O&M expenses for the wastewater control devices and programs for the three time periods are:

Year	$ Million
1995	44
2000	405
2010	573

Table 4-5 presents the details on what wastewater control devices and programs are covered by the O&M expenses. Two control systems and programs that contribute to a major share of the O&M expenses are:

- Reduction of toxicity in wastewater effluents
- Maximum practical reuse of process wastewater

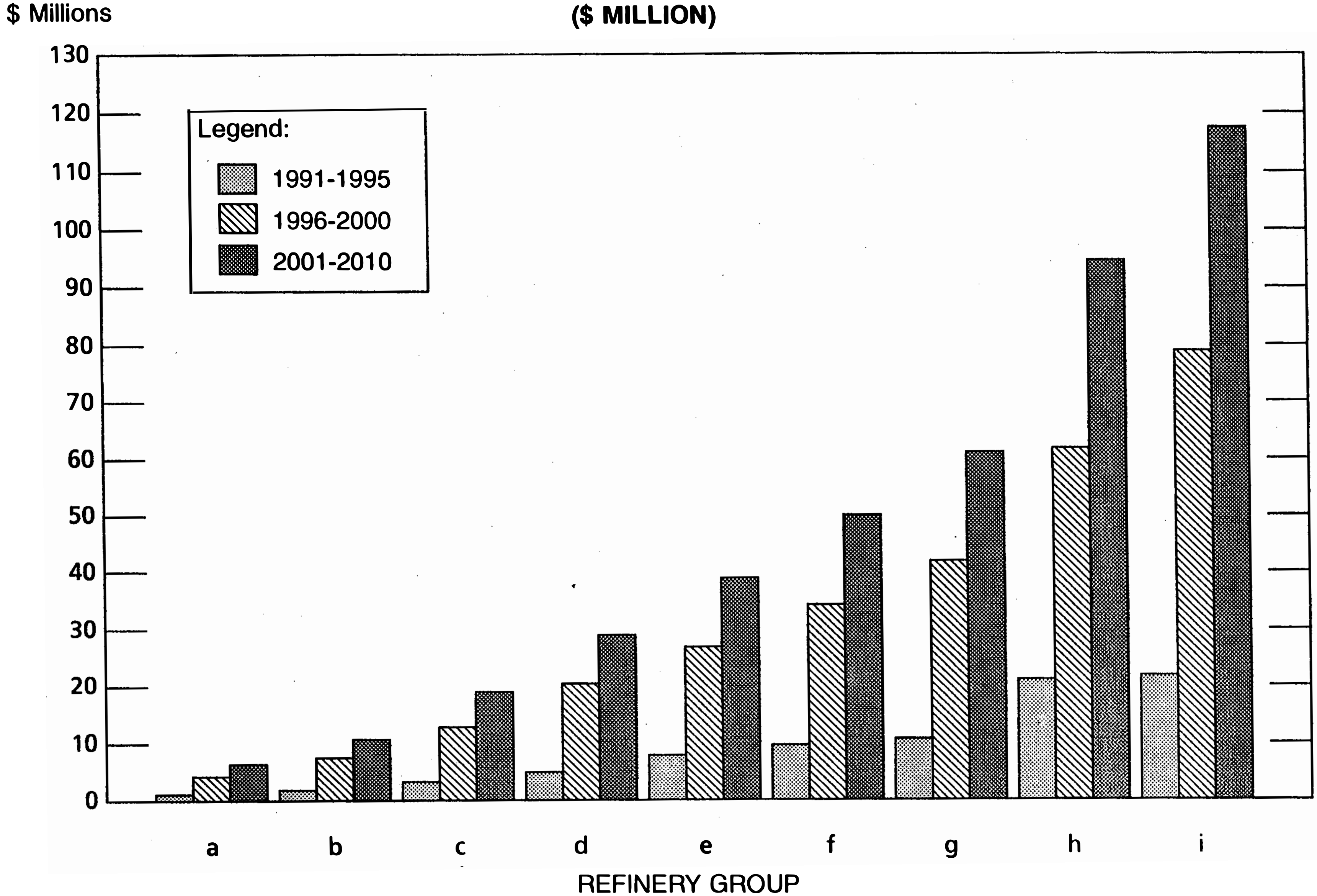
Table 4-3

CAPITAL INVESTMENT FOR WASTEWATER CONTROL TECHNOLOGIES PER REFINERY PER GROUP ($ MILLION)

			Capital Investment Per Refinery			
Group	No. of Refineries Per Group	Capital Investment Per Group	1991-1995	1996-2000	2001-2010	Total
a	26	312	1	5	6	12
b	24	481	2	7	11	20
c	40	1,401	3	13	19	35
d	28	1,526	5	20	29	54
e	12	886	8	27	39	74
f	24	2,249	10	34	50	94
g	11	1,250	11	42	61	114
h	14	2,482	21	62	94	177
i	8	1,744	22	79	117	218
Total	187	12,331	--	--	--	--

Figure 4-3

CAPITAL INVESTMENT FOR WASTEWATER CONTROL TECHNOLOGIES PER REFINERY PER GROUP ($ MILLION)



1092001-2

Table 4-4

WASTEWATER TECHNOLOGY COSTS
INCREMENTAL ONE-TIME COST
ALL REFINERY GROUPS
($ MILLION)

	Implementation Period			
	91-95	96-00	01-10	Total
CWA REAUTHORIZATION				
Max. Practical Reuse of Process Wastewater	0	0	0	0
Reduce Toxicity of Effluent (Biomonitoring)				
Filtration of ASP/PACT Treatment	0	0	0	0
Two-stage Activated Sludge (ASP) and Powdered Activated Carbon (PACT)	0	0	0	0
Incineration of Sludge	0	0	0	0
Target Heavy Metal Precipitation	0	0	0	0
Subtotal, REDUCE TOXICITY	0	0	0	0
Reduce Oil to Sewer, Closed Loop Sampler	0	0	0	0
Reduce Runoff from Unpaved Process Area	0	0	0	0
Sediments Discharged from WWTP	0	0	8	8
Subtotal, CWA REAUTHORIZATION	0	0	8	8
STORM WATER QUALITY				
Store and Treat Quantity of Contaminated Process Water and Storm Water From 10-year Storm				
Build Lift Stations	0	0	0	0
Store and Treat Storm water Runoff	0	0	0	0
Subtotal, STORM WATER QUALITY	0	0	0	0
GROUNDWATER ISSUES				
Retrofit All Storage Tanks - Double Bottoms	0	0	0	0
Install Membrane Liners	0	0	0	0
Subtotal	0	0	0	0
Raise or Replace Below Grade Process Piping	0	0	0	0
Hard Pipe Tank Drawoff	0	0	0	0
Subtotal	0	0	0	0
Subtotal, GROUNDWATER ISSUES	0	0	0	0
All Refinery Groups Incremental Capital Investment	0	0	8	8

Note: Columns and rows may not add due to rounding.

Table 4-5

WASTEWATER TECHNOLOGY COSTS
INCREMENTAL O&M COST
ALL REFINERY GROUPS
($ MILLION/YEAR)

	Implementation Period		
	1995	2000	2010
CWA REAUTHORIZATION			
Max. Practical Reuse of Process Wastewater	0	0	123
Reduce Toxicity of Effluent (Biomonitoring)			
Filtration of ASP/PACT Treatment	0	34	34
Two-stage Activated Sludge (ASP) and Powdered Activated Carbon (PACT)	0	221	221
Incineration of Sludge	0	99	99
Target Heavy Metal Precipitation	0	10	10
Subtotal, REDUCE TOXICITY	0	365	365
Reduce Oil to Sewer, Closed Loop Sampler	< 1	1	< 1
Reduce Runoff from Unpaved Process Area	6	2	0
Sediments Discharged from WWTP	0	0	0
Subtotal, CWA REAUTHORIZATION	6	368	489
STORM WATER QUALITY			
Store and Treat Quantity of Contaminated Process Water and Storm Water from 10-year Storm			
Build Lift Stations	1	1	2
Store and Treat Storm Water Runoff	17	17	34
Subtotal, STORM WATER QUALITY	18	18	37
GROUNDWATER ISSUES			
Retrofit All Storage Tanks - Double Bottoms	12	12	23
Install Membrane Liners	0	0	10
Subtotal	12	12	33
Raise or Replace Below Grade Process Piping	6	6	12
Hard Pipe Tank Drawoff	2	2	4
Subtotal	8	8	16
Subtotal, GROUNDWATER ISSUES	19	19	48
All Refinery Groups Incremental Capital Investment	44	405	573

Note: Columns and rows may not add due to rounding.

5.0 HAZARDOUS AND NONHAZARDOUS SOLID WASTE SECTOR

5.0 HAZARDOUS AND NONHAZARDOUS SOLID WASTE SECTOR

Refinery hazardous and nonhazardous solid waste programs being implemented during the 1990s and the first decade of the 21st century will result from a number of regulatory initiatives that target disposal of solid waste. The premises addressed under the broad category of solid and hazardous waste utilized in this study are divided into the following six subcategories:

- Groundwater issues
- Above ground storage tanks
- RCRA Reauthorization
- RCRA Toxicity Characteristic (TC) Land Disposal Restrictions (LDR)
- RCRA corrective action
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)

The incremental cost estimates for U.S. refineries to meet the NPC's premises of solid and hazardous waste regulations are:

$ Million

Item	1991-1995	1995	1996-2000	2000	2001-2010	2010	Total
Capital Investment	464	---	1,289	---	1,922	---	3,675
One-Time Costs	< 1	---	1,075	---	1,075	---	2,150
Total	464	---	2,364	---	2,997	---	5,825
O&M Expenses	---	61	---	1,139	---	100	---

Note: Costs are expressed in mid-1990 U. S. Gulf Coast dollars.

5.1 Regulatory Drivers

5.1.1 Resource Conservation and Recovery Act

The RCRA was promulgated in 1976 as a strict liability statute under which the Congress of the United States sought to regulate the generation, transportation, treatment, storage, and disposal of solid wastes. The legislation focused on the management of the major subset of solid waste generally referred to as hazardous waste. Hazardous waste is regulated under Subtitle C of RCRA. Under Subtitle C, Congress charged the EPA with the identification and listing of hazardous wastes.

The EPA created two different hazardous waste categories. The first, characteristic hazardous wastes and the second, listed hazardous wastes. Characteristic hazardous wastes meet a specific criteria such as having a flash point of less than 140 °F or a pH of less than 2 or greater than 12.5. The listed hazardous wastes are not as straightforward. The EPA initially selected five typical refinery waste streams and "listed" these wastes as hazardous based on the lead and chromium content of the waste streams. The five refinery waste streams are:

- Disolved air flotation float (K048)
- Slop oil emulsion solids (K049)
- Heat exchanger bundle cleaning sludge (K050)
- API separator sludge (K051)
- Leaded tank bottoms sludge (K052)

In 1990, the EPA added two listings to the refinery specific hazardous wastes and they are:

- Petroleum refinery primary oil/water/solids separation sludges (F037)
- Petroleum refinery secondary oil/water/solids separation sludges (F038)

The listed wastes do not have associated with them specific criteria or concentrations outside of which the waste is not considered hazardous. Therefore, any time the listed waste is present, no matter what the concentration, a hazardous waste exists.

RCRA regulates all aspects of the management of hazardous wastes. It is a dynamic and evolving regulatory program which may add additional chemicals and waste streams to the original regulated parameters and has done so several times since its original promulgation in 1976.

5.1.2 CERCLA

CERCLA was enacted to provide a mechanism and the financial means to address releases of hazardous substances, pollutants, or contaminants to the environment primarily from abandoned land sites. The Legislation specifically excludes petroleum from consideration as a pollutant or contaminant. CERCLA has broad, far reaching authority to require the remediation of environmental hazards even allowing the federal government to undertake the work and recover costs plus penalties from those involved in the cause of the threat to the environment.

The loss of the petroleum exclusion in CERCLA could subject the petroleum industry, in general, and the refining industry, specifically, to the threat of a costly clean up of any site, abandoned facility, unit, old landfill, surface impoundment or other land disposal unit anywhere within a refinery's control. The loss of this exclusion could also subject the refining industry to involvement in cleanup actions anywhere refinery waste has been disposed of in the past.

5.2 Control Technologies

The control technologies premised by the NPC are based upon provisions in the RCRA and CERCLA regulations and anticipated features of the rules in the various states that will be promulgated to further improve the disposition of hazardous and nonhazardous solid wastes. These are summarized in Table 5-1.

5.2.1 Groundwater Monitoring

Existing technologies will be used in order to control the release of hazardous waste constituents from refinery streams to groundwater. The first step in controlling such releases is the detection of the contaminate plume so that appropriate responses can be undertaken to mitigate the environmental impacts from releases. NPC has chosen the mechanism of monitoring the perimeter of the facility as a means of controlling offsite releases.

Groundwater monitoring has always been a significant part of RCRA. Generally however, the monitoring is required at hazardous waste unit boundaries, not at the perimeter of the facility. This unit monitoring is necessary in order to meet the RCRA mandated immediate detection of a release from the unit. At refineries, potential groundwater contamination and offsite migration is also likely from product spills which would not be detected by the existing hazardous waste unit monitoring systems. A facility operating under RCRA is responsible for the offsite migration of any hazardous constituent, not just those contained in the original hazardous waste. Therefore, the regulatory agencies can require the remediation of any constituent which is migrating offsite. The petroleum refining industry apparently already recognizes the hazards associated with the offsite migration of such materials. In the responses to the survey data submitted to NPC, a significant percentage of all refineries in the United States already have some sort of perimeter groundwater monitoring system.

Groundwater monitoring is extremely dependent on site-specific geological factors. It is not possible in a study of this nature to predict the exact design characteristics of a groundwater monitoring well which would fit every circumstance. A typical RCRA groundwater monitoring well was conceptualized as indicated in Figure 5-1.

In this study, the average well spacing is assumed to be 200 feet along the refinery perimeter. Again, a factor such as well spacing is very dependent on the geology of the site. Two-hundred feet spacing may be adequate in some locations but not in others.

The estimated well depth of 50 feet is a compromise in order to estimate the cost of a monitoring system. While in the U.S. Gulf Coast area such a well may be realistic or even significantly too deep. However, in other areas of the U.S. such a well depth could conceivably be much too shallow, by several hundred feet.

Any RCRA modeled groundwater monitoring system requires at least one up gradient (to the direction of flow of groundwater) monitoring well to collect data that is not affected by the unit being monitored. This allows the affects of the unit on groundwater to be determined. Further, an acceptable RCRA system would require at least three downgradient wells.

Table 5-1

HAZARDOUS AND NONHAZARDOUS SOLID WASTES TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject	Limit/Scope	Technology	Percent Implementation During		
			1991 - 1995	1996 - 2000	2001 - 2010
Groundwater Issues Pollution prevention - Facility wide	Remediation	Install and operate ground water monitoring wells along two sides of the facility perimeter - 200 foot spacings	0	50	50
	Remediation	Install and operate ground water recovery wells along two sides of the facility perimeter - 200 foot spacings	0	50	50
Above Ground Tanks	40 years old [1]	Demolish and replace with like capacity 1/2 tanks older than 40 years old. Light hydrocarbon tanks - double bottom, double seals - heavy hydrocarbon - double bottoms.	0	25	50
RCRA Reauthorization	Additional waste listings	Additional refinery wastes and waste like products may be listed as hazardous wastes in the future. These additional wastes which might include non-leaded tank bottoms, spent FCC catalyst, spent caustic, etc. will require additional handling expenditures for storage, transportation for disposal and disposal or treatment.	0	100	0

Note: [1] Upside sensitivity costs were developed.

Table 5-1 (Cont'd)

HAZARDOUS AND NONHAZARDOUS SOLID WASTES TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject	Limit/Scope	Technology	Percent Implementation During		
			1991 - 1995	1996 - 2000	2001 - 2010
RCRA TC LDR	Surface impoundments [1]	Most RCRA surface impoundments will be closed or retrofitted to meet RCRA minimum technology requirements prior to '95. A few impoundments may require retrofit after that date. These impoundments may be newly listed waste facilities or units which are retrofitted.	100	0	0
RCRA Corrective Action Pollution Prevention	Remediate contaminated soil[1]	As regulations become more stringent, non-SWMU contaminated soils will require monitoring to determine any threat to the environment and eventually treatment or disposal.	0	25	25
	SWMU's - nonhazardous	Solid Waste Management Units (SWMU's) which manage nonhazardous solid waste will be monitored to ensure that the materials do not pose a threat to the environment.	25	25	0
	SWMU's - inactive, hazardous [1]	SWMU's which managed hazardous waste and are now inactive will be monitored, closed or treated in place or closed by removal according to RCRA closure requirements.	25	25	25

Note: [1] Upside sensitivity costs were developed.

Table 5-1 (Cont'd)

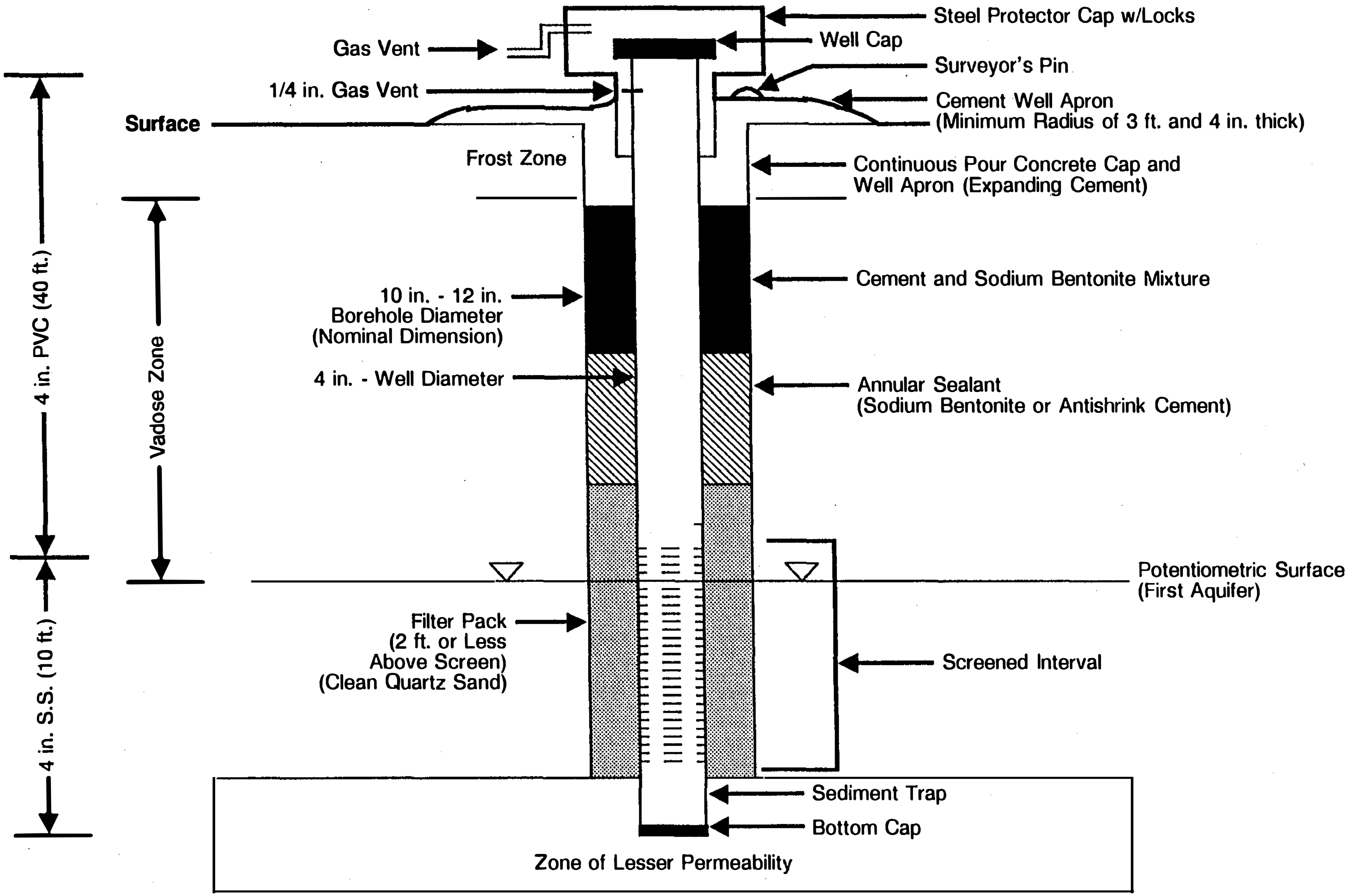
HAZARDOUS AND NONHAZARDOUS SOLID WASTES TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject	Limit/Scope	Technology	Percent Implementation During		
			1991 - 1995	1996 - 2000	2001 - 2010
RCRA Corrective Action (cont'd)	SWMU's - active, hazardous (1)	SWMU's which managed hazardous waste and are now active will be monitored, closed or treated in place or closed by removal according to RCRA closure requirements.	0	0	100
CERCLA - Loss of the Petroleum Exclusion	Nonhazardous to hazardous	Issue item to discuss possible impacts of the loss of the petroleum exclusion on the refining industry.	---	---	---

Note: (1) Upside sensitivity costs were developed.

Figure 5-1

TYPICAL RCRA MONITORING WELL



1092001-2

5.2.2 Recovery Wells

The conceptual groundwater recovery well is quite similar to the groundwater monitoring well. The only differences in the two is that the recovery well would have a submersible pump installed. Also, due to the different use of the wells, they would be spaced much closer together. Recovery well spacing would be 20 feet which is the maximum recommended spacing for this shallow (50 feet) recovery well in EPA guidance.

5.2.3 Solid Waste Management Units (SWMUs)

5.2.3.1 Nonhazardous SWMUs

The control technology concept used for nonhazardous SWMUs is to monitor the unit for releases to groundwater. The control technology utilizes the same monitoring well conceptual design as is used in the perimeter groundwater monitoring system. All the assumptions relative to well spacing and depth and construction are the same as those used for monitoring wells.

5.2.3.2 Inactive Hazardous SWMUs

The are two options for a control technology to be used on inactive hazardous SWMUs: Closure in place (capping); and clean closure (removal). Both options are currently allowed under RCRA as methods for dealing with the closure of a RCRA unit. Closure in place requires the installation of a cap over the waste which is left in place. The conceptual design for the cap is in accordance with EPA guidance and consists of multiple layers to resist penetration of moisture through the cap. A typical RCRA cap is shown in Figure 5-2. Figure 5-3 shows a typical RCRA landfill including the liners beneath the typical design that would be appropriate for a new landfill. Generally, an existing landfill being closed would only receive a cap (i.e., no liners below the waste would be installed).

In addition to the cap, a system of groundwater monitoring wells would be installed around the perimeter of the unit. The monitoring wells are designed and placed in the same manner as those for the perimeter groundwater monitoring system.

Clean closure of the SWMU necessitates the removal and disposal of all hazardous waste, liners, and contaminated soil from the unit. Once these materials have been removed, the resulting hole in the ground is backfilled with clean fill material. No monitoring is required as any source of contamination to the environment has been removed.

5.2.3.3 Active Hazardous SWMUs

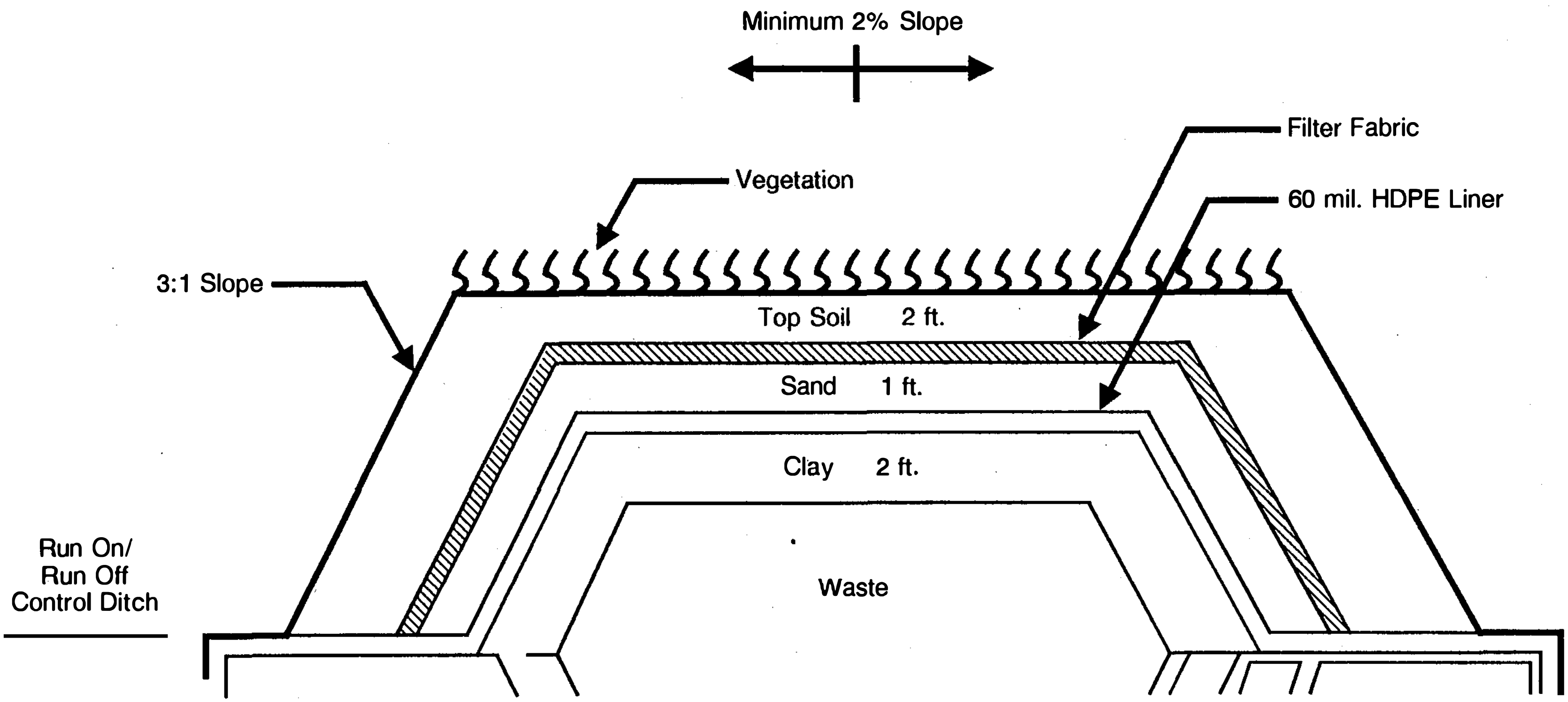
The closure options, activities, and control technologies for active hazardous SWMUs are the same as those for inactive hazardous SWMUs.

5.2.4 Surface Impoundments

An NPC premise assumed that all surface impoundments subject to RCRA will be retrofitted to meet RCRA minimum technology requirements (MTR) or closed by 1995. Therefore, the control technology of closure in place or removal would already have been implemented. Those units

Figure 5-2

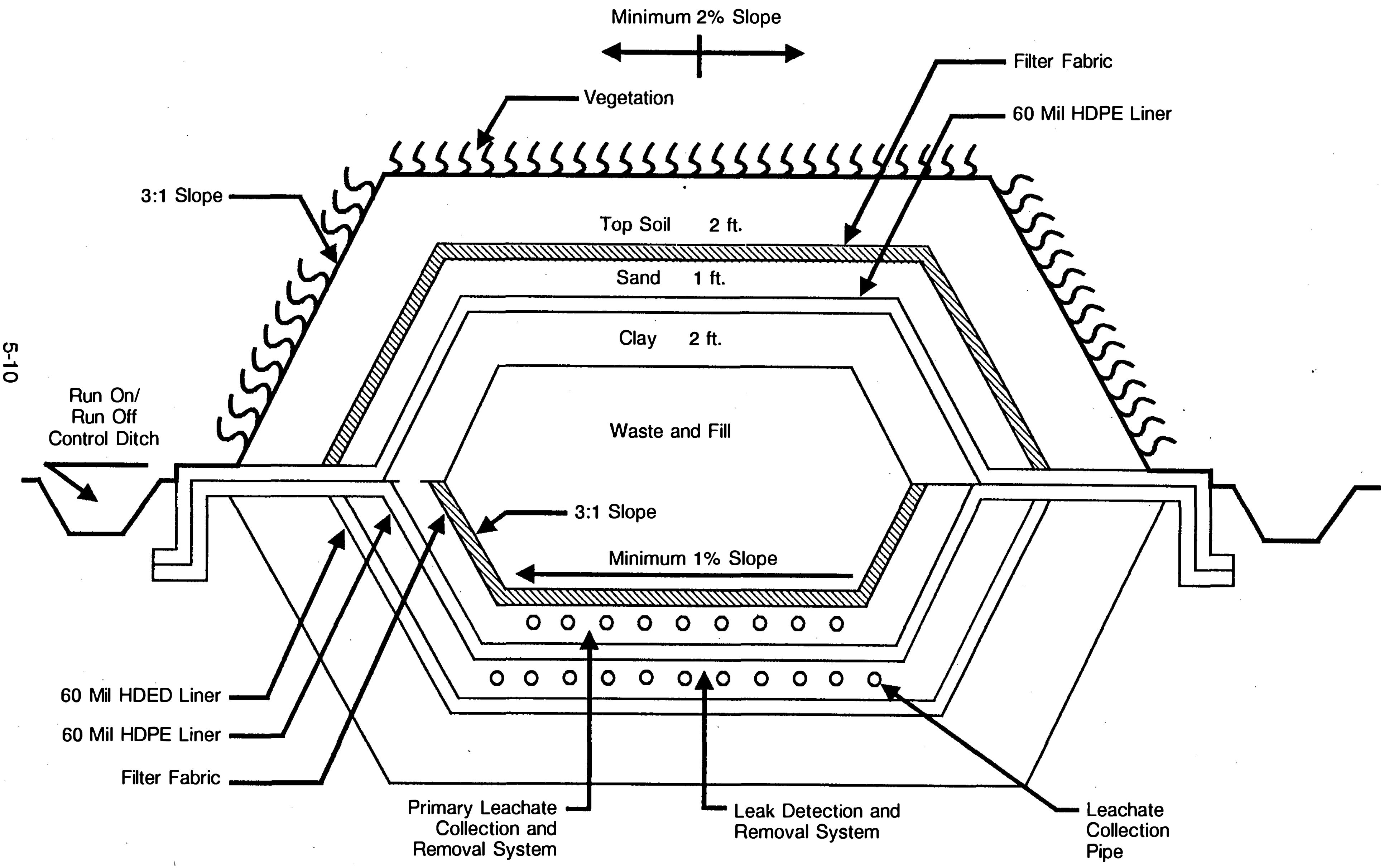
TYPICAL RCRA CAP



1092001-2

Figure 5-3

TYPICAL RCRA LANDFILL



1092001-2

which were closed in place would only require monitoring of the groundwater and maintenance of the cap during the study period.

Upon receiving the results of the NPC Survey, a small percentage of the overall number of refineries indicated that a limited amount of retrofitting of surface impoundments would take place after 1995. The conceptual RCRA MTR surface impoundment consists of a typical unit and is shown in Figure 5-4. Figure 5-5 illustrates the surface impoundment leachate collection pipes, and Figure 5-6 shows detail of the spacing of the pipes. The leachate collection system consists of the perforated pipes in the sand layer, a collection pipe header, a manhole, and a leachate pump installed in the manhole.

In addition to the MTR surface impoundment, a system of groundwater monitoring wells of the same design as in the perimeter groundwater monitoring system would be installed around each impoundment.

5.2.5 RCRA Reauthorization - New Listings

5.2.5.1 Non-Leaded Tank Bottoms

The control technology for dealing with the newly listed waste, non-leaded tank bottoms, is offsite incineration. The waste is generated during routine, periodic cleaning of tankage at the refinery.

Until the waste is generated, upon removal from the tanks, it is not a hazardous waste. Therefore the disposal of this material can take place periodically when the tanks are cleaned out without triggering RCRA permitting requirements.

5.2.5.2 Spent Fluid Cracking Catalyst

Spent FCC cracking catalyst recovered and/or removed will be drummed for disposal in an offsite landfill.

5.2.5.3 Liquid Waste Amine Streams

Liquid waste amine streams will be incinerated offsite.

5.2.5.4 Sulfur

Contaminated sulfur product will be landfilled offsite.

5.2.5.5 Spent Caustics

The control technology for spent caustics is to neutralize the caustic with hydrochloric acid. The resulting aqueous solution will be discharged to the facilities existing wastewater treatment plant for treatment and disposal.

Figure 5-4

TYPICAL RCRA DOUBLE-LINED SURFACE IMPOUNDMENT

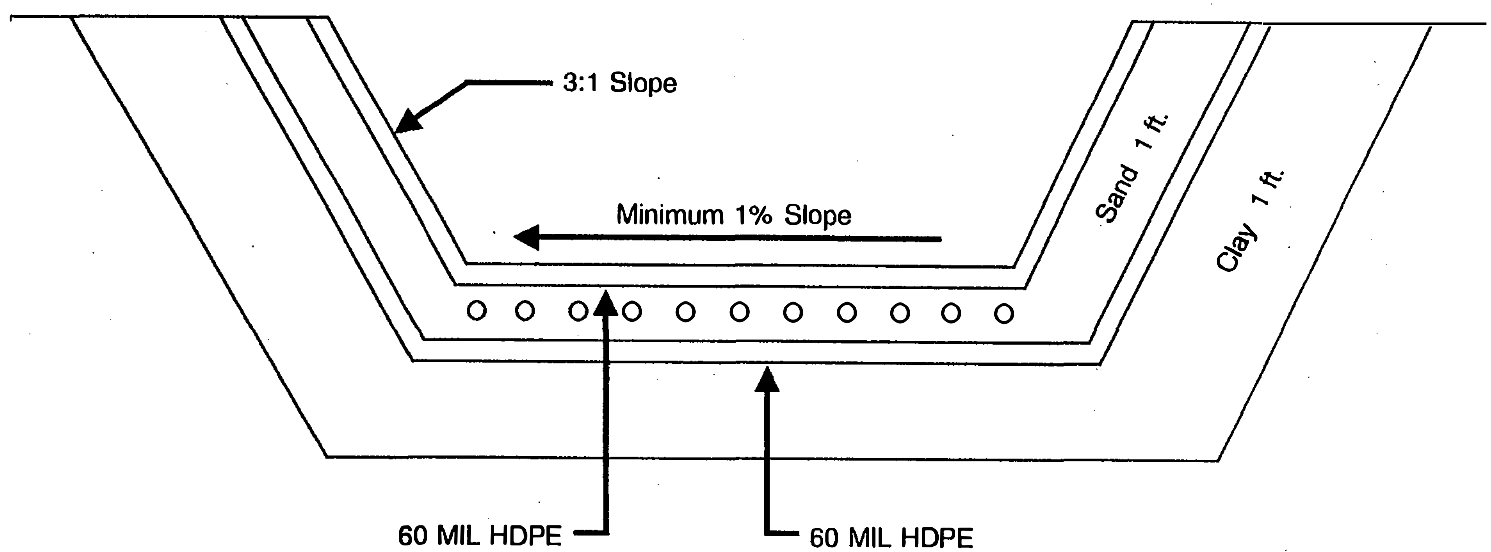


Figure 5-5

OVERHEAD VIEW LEACHATE COLLECTION SYSTEM

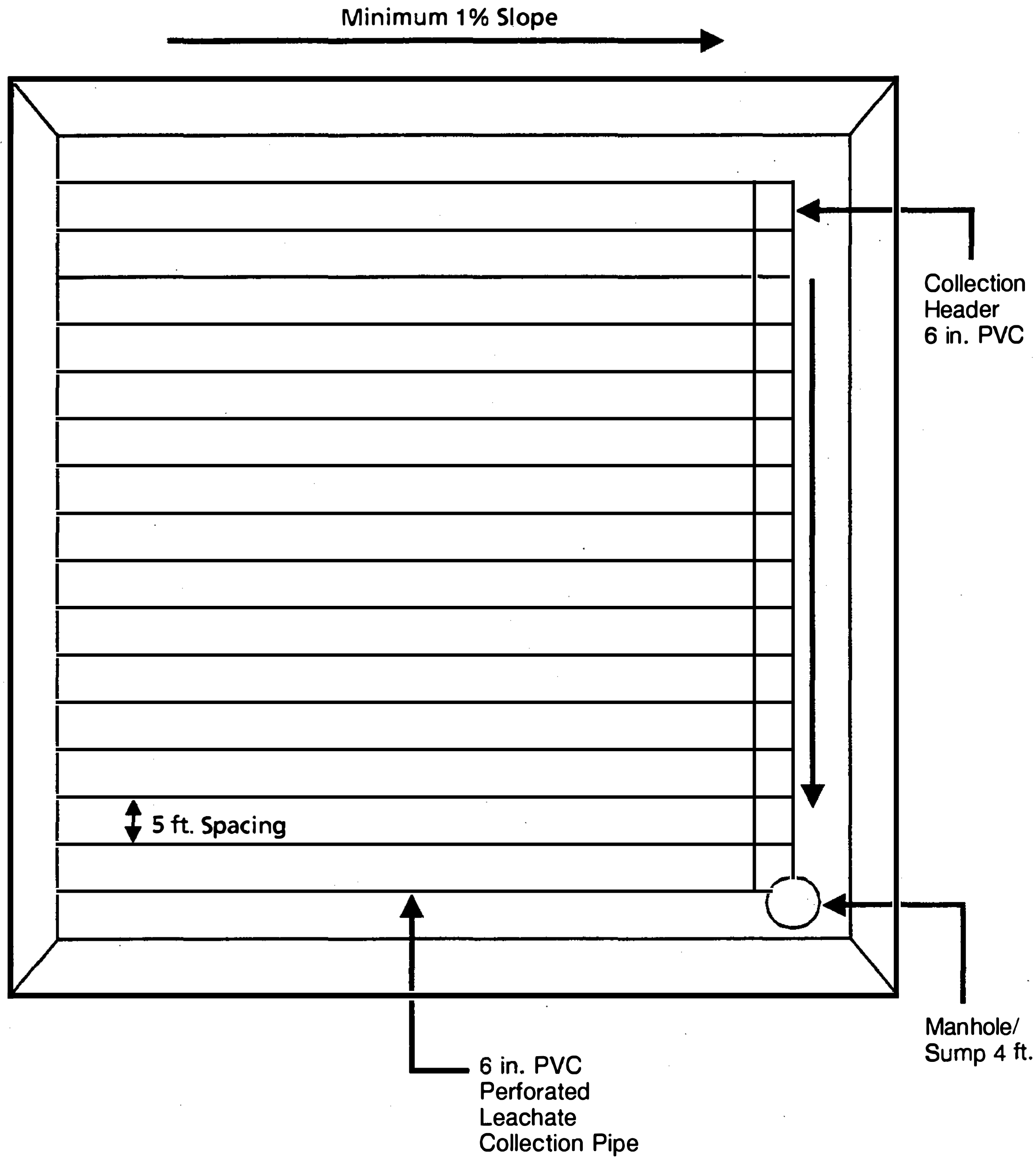
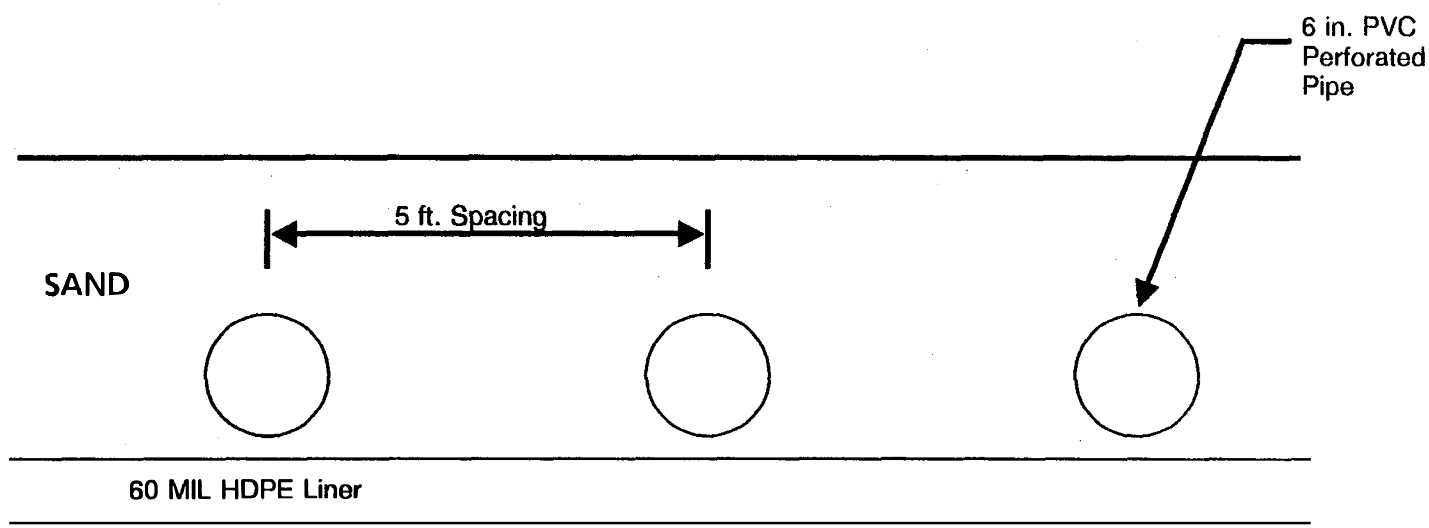


Figure 5-6

DETAIL OF LEACHATE COLLECTION SYSTEM



5.2.6 Contaminated Soils

There are three options of control technologies for contaminated soils. Just as for solid waste management units the contaminated soil areas may be closed in place or removed. This soil may or may not be a RCRA hazardous waste. Therefore, if the soil to be removed is not a hazardous waste, just contaminated soil, it would be landfilled. If the soil is a hazardous waste then the disposal method for the soil would be incineration in a RCRA hazardous waste incinerator offsite. No unit groundwater monitoring wells would be installed around contaminated soil which is closed in place.

5.2.7 Tanks 40+ Years Old--Light Hydrocarbon Service

The control technology to alleviate environmental hazard from light hydrocarbon service tankage is to replace older tanks. An NPC assumption is that one-half of the 40+ year old tanks would be replaced during the 1996 through 2010 period. The possibility of the tank bottom plates leaking implies that additional contaminated soil problems exist under the tanks to be replaced. It is assumed that this contaminated soil was not included in the contaminated soil reported in response to the NPC Survey. There are three possibilities with regard to soil under the tanks. First is no contaminated soil under the tank. Second is that the soil beneath the tanks is contaminated, but not hazardous, and can be landfilled. Finally, the soil beneath the tanks is contaminated and rated as hazardous and must be incinerated.

5.2.8 Tanks 40+ Years Old--Heavy Hydrocarbon Service

The control technology and options for heavy hydrocarbon service tanks are the same as those for light hydrocarbon service tanks.

5.3 Summary

5.3.1 Incremental Capital Investments

The estimated incremental capital investments for control systems and programs for disposing of hazardous and nonhazardous solid wastes by the U.S. refining industry during the 1991 through 2010 period is $3,675 million (mid-1990 U.S. Gulf Coast). The investment will be spread over three areas as indicated below:

Item	$ Million	Percent
Groundwater Issues	384	10.5
Aboveground Tanks	1,897	51.6
Other RCRA Issues	1,394	37.9

Table 5-2 presents the details on what control technologies and programs the investments are being spent on and the time periods being covered. The majority of the $3,675 million is estimated to be spent in the 2001 through 2010 time frame as indicated by the data listed below:

Period	$ Million	Percent
1991-1995	464	12.6
1996-2000	1,289	35.1
2001-2010	1,922	52.3

The major areas the investments will be made is in the replacement of above ground storage tankage that are in both light and heavy hydrocarbon service and for RCRA corrective action on inactive hazardous SWMUs.

Capital investments for control technologies and programs per refinery per group are presented in Table 5-3 and illustrated in Figure 5-7. Major capital investment occurs in the 2001 through 2010 time frame for refineries in all nine groups.

5.3.2 Incremental One-Time Costs

The estimated incremental one-time costs for control systems and programs for disposing of hazardous and nonhazardous solid wastes by the U.S. refining industry during the 1991 through 2010 period is $2,150 million (mid-1990 U.S. Gulf Coast). The one major program contributing nearly all the one-time costs is the remediation of contaminated soil.

Table 5-4 presents the details on what control technologies and programs the one-time costs are being made. Total one-time costs for control technologies per refinery per group are presented in Table 5-5. The one-time costs for remediation of contaminated soils for refineries in Groups f and h and are rather major, about $33 million and $30 million per refinery, respectively.

5.3.3 Incremental O&M Expenses

The estimated incremental O&M expenses for the control systems and programs for disposing of hazardous and nonhazardous solid wastes for their time periods are:

Year	$ Million
1995	61
2000	1,139
2010	100

Table 5-6 presents the details on what control systems and programs are covered by these O&M expenses.

One program contributes a major share to the O&M expenses and the program is RCRA Reauthorization - new listings. Disposal of five waste materials that are produced during normal refinery operations creates major cost for refineries.

Table 5-2

HAZARDOUS AND NONHAZARDOUS SOLID WASTE CONTROL TECHNOLOGY COSTS INCREMENTAL CAPITAL INVESTMENT ALL REFINERY GROUPS ($ MILLION)

	Implementation Period			
	91-95	96-00	01-10	Total
Groundwater Issues				
Recovery Wells	0	183	183	366
Monitoring Wells	0	9	9	17
Subtotal	0	192	192	384
Above Ground Tanks				
Light Hydrocarbons	0	381	763	1,144
Heavy Hydrocarbons	0	251	502	753
Subtotal	0	633	1,265	1,897
RCRA Reauthorization - New Listings	0	1	0	1
RCRA TC LDR - Surface Impoundments	0	0	0	0
RCRA Corrective Action				
Remediate Contaminated Soil	0	0	0	0
SWMUs - Nonhazardous	40	40	0	79
SWMUs - Inactive, Hazardous	425	425	425	1,274
SWMUs - Active, Hazardous	0	0	41	41
Subtotal	464	464	465	1,393
Total All Refinery Groups Incremental Capital Investment	464	1,289	1,922	3,675

Note: Columns and rows may not add due to rounding.

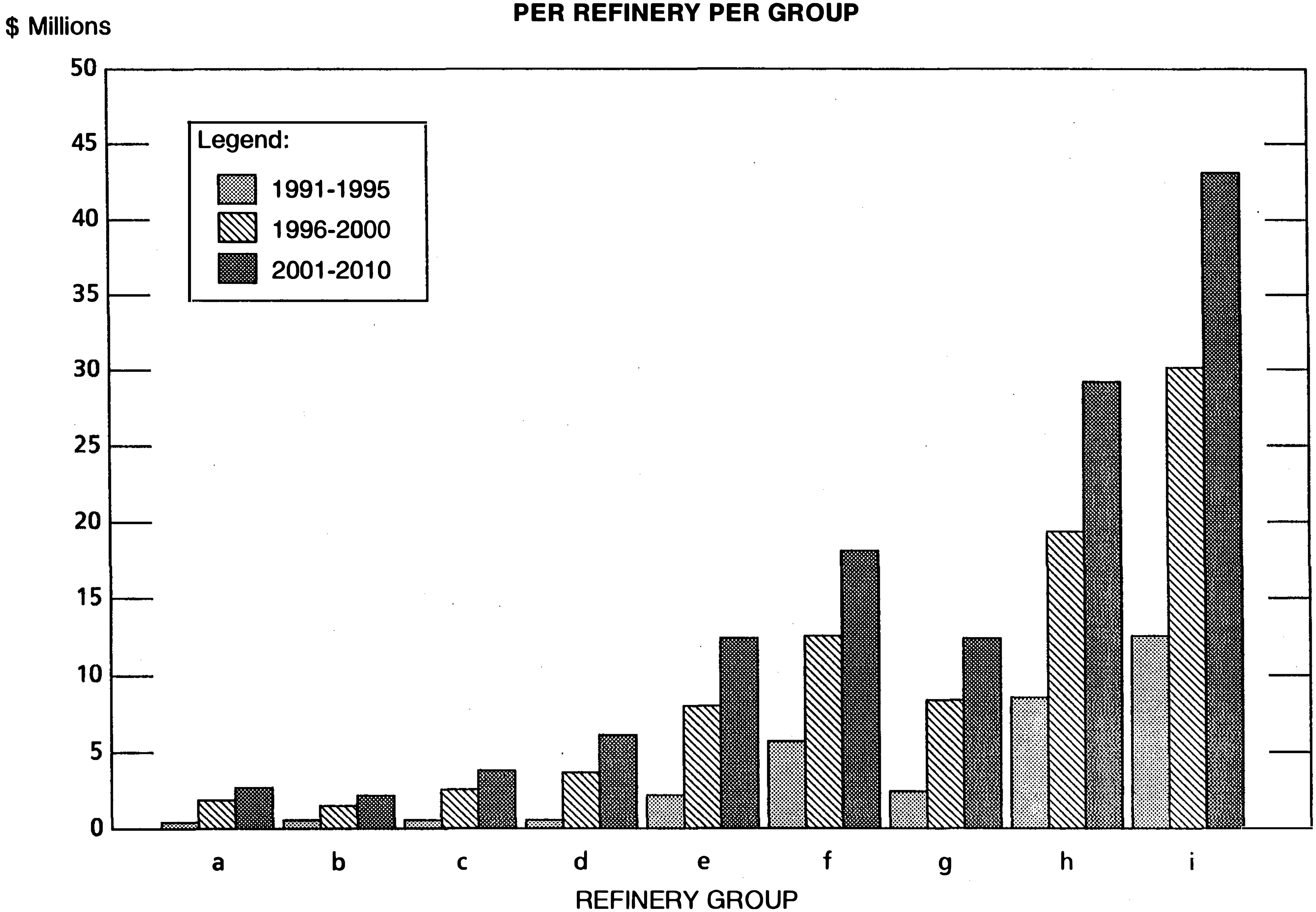
Table 5-3

CAPITAL INVESTMENTS FOR HAZARDOUS AND NONHAZARDOUS SOLID WASTE CONTROL TECHNOLOGIES PER REFINERY PER GROUP ($ MILLION)

			Capital Investment Per Refinery			
Group	No. of Refineries Per Group	Capital Investment Per Group	1991-1995	1996-2000	2001-2010	Total
a	26	131	<1	2	3	5
b	24	100	<1	2	2	4
c	40	273	<1	3	4	7
d	28	288	<1	4	6	10
e	12	271	2	8	12	22
f	24	873	6	12	18	36
g	11	255	3	8	12	23
h	14	798	9	19	29	57
i	8	686	13	30	43	86
Total	187	3,675	-	-	-	-

Figure 5-7

CAPITAL INVESTMENT FOR HAZARDOUS AND NONHAZARDOUS SOLID WASTE CONTROL TECHNOLOGIES PER REFINERY PER GROUP



1092001-2

Table 5-4

HAZARDOUS AND NONHAZARDOUS SOLID WASTE TECHNOLOGY COSTS
INCREMENTAL ONE-TIME COSTS
ALL REFINERY GROUPS
($ MILLION)

	Implementation Period			
	91-95	96-00	01-10	Total
Groundwater Issues				
Recovery Wells	0	0	0	0
Monitoring Wells	0	1	1	2
Subtotal	0	1	1	2
Above Ground Tanks				
Light Hydrocarbons	0	0	0	0
Heavy Hydrocarbons	0	0	0	0
Subtotal	0	0	0	0
RCRA Reauthorization - New Listings	0	0	0	0
RCRA TC LDR - Surface Impoundments	< 1	0	0	< 1
RCRA Corrective Action				
Remediate Contaminated Soil	0	1,074	1,074	2,148
SWMUs - Nonhazardous	0	0	0	0
SWMUs - Inactive, Hazardous	0	0	0	0
SWMUs - Active, Hazardous	0	0	0	0
Subtotal	0	1,074	1,075	2,150
Total All Refinery Groups				
Incremental Capital Investment	< 1	1,075	1,075	2,150

Note: Columns and rows may not add due to rounding.

Table 5-5

ONE-TIME COSTS FOR HAZARDOUS AND NONHAZARDOUS SOLID WASTE CONTROL TECHNOLOGIES PER REFINERIES PER GROUP ($ MILLION)

			One-time Costs Per Refinery			
Group	No. of Refineries Per Group	Capital Investment Per Group	1991-1995	1996-2000	2001-2010	Total
a	26	16	-	<1	<1	<1
b	24	16	-	<1	<1	<1
c	40	449	-	5	6	11
d	28	139	-	2	3	5
e	12	110	-	4	5	9
f	24	789	-	16	17	33
g	11	188	-	8	9	17
h	14	415	-	15	15	30
i	8	28	-	1	2	3
Total	187	2,150	-	-	-	-

O:\PROPOSAL\1093029\SEC5

Table 5-6

HAZARDOUS AND NONHAZARDOUS SOLID WASTE TECHNOLOGY COSTS
INCREMENTAL O&M EXPENSES
ALL REFINERY GROUPS
($ MILLION/YEAR)

	Implementation Period		
	1995	2000	2010
Groundwater Issues			
Recovery Wells	0	37	37
Monitoring Wells	0	7	7
Subtotal	0	45	45
Above Ground Tanks			
Light Hydrocarbons	0	2	4
Heavy Hydrocarbons	0	1	3
Subtotal	0	3	6
RCRA Reauthorization - New Listings	0	1,011	0
RCRA TC LDR - Surface Impoundments	14	0	0
RCRA Corrective Action			
Remediate Contaminated Soil	0	32	32
SWMUs - Nonhazardous	32	32	0
SWMUs - Inactive, Hazardous	15	15	15
SWMUs - Active, Hazardous	0	0	2
Subtotal	47	79	49
Total All Refinery Groups Incremental Capital Investment	61	1,139	100

Note: Columns and rows may not add due to rounding.

5.4 Sensitivity Analysis

The study considers six sensitivity analyses to evaluate the costs impacts for possible changes and/or modifications in hazardous and nonhazardous solid waste regulations. Each of the six sensitivity cases could have a major capital impact on the U.S. refining industry that would range from $0.5 to $85.0 billion.

5.4.1 Inactive Hazardous SWMUs

The inactive hazardous SWMUs sited in refineries includes only one sensitivity case. The Base Case is closure in place of SWMUs in 187 U.S. refineries to determine the total cost to the U.S. refining industry.

Case A deals with the removal of the SWMUs from the 187 refineries. The contaminated soil is removed and the assumption is made that the material is incinerated, 50 percent onsite and 50 percent offsite.

The 187 refineries could incur an estimated $1.7 billion in capital expenditures to close their inactive hazardous SWMUs in place, Base Case. However, if the 187 refineries decided to close the SWMUs and remove the hazardous waste and incinerate the waste, an estimated one-time cost of about $85.1 billion would be incurred, Case A. The capital expenditures of some $1.7 billion incurred in the Base Case would not be required for Case A.

The estimated capital investment, one-time costs, and O&M expenses for the Base Case and Case A by refinery groups are presented in Table 5-7. The net values (capital investments plus one-time costs) by refinery groups are illustrated in Figure 5-8. Refineries in Groups f, h, and i would be impacted very significantly by the closure of inactive hazardous SWMUs and incinerate the hazardous material; $25.4 billion, $ 22.8 billion, and $ 16.3 billion, respectively. The total U.S. refining industry would be impacted to a total incremental net investment of about $83.4 billion.

5.4.2 Active Hazardous SWMUs

Active hazardous SWMUs sited in refineries includes only one sensitivity analyses. The Base Case is closure in place using the NPC Survey data (14 refineries responded) to determine the number of facilities affected.

Case A deals with the removal of the SWMU from the 14 refineries. The contaminated soil is removed and the assumption is made that the material is incinerated, 50 percent onsite and 50 percent offsite.

The 14 refineries could incur an estimated $41 million in capital expenditures to close their active hazardous SWMUs in place, Base Case. However, if the 14 refineries decided to close the SWMUs and remove the hazardous waste and incinerate the waste, an estimated one-time cost of about $2.0 billion would be incurred, Case A. The capital expenditures of the $41 million incurred in the Base Case would not be required for Case A.

The estimated capital investment and one-time costs for the Base Case and Case A by refinery groups are presented in Table 5-8. The net values (capital investments plus one-time costs) by refinery groups are illustrated in Figure 5-9. The four refineries in Groups g and h would be impacted by about $244 million each by the closure of an active hazardous SWMU and incinerating the hazardous materials. The 14 refineries would be impacted for a total incremental net investment of about $1.95 billion.

5.4.3 Surface Impoundment Retrofit

The retrofitting of surface impoundments sited in refineries considers two sensitivities. The Base Case is no action - meaning that no retrofitting would be done. Case A allows the contaminated soil removed in the retrofitting process to be landfilled. While this assumes that the soil is not RCRA hazardous, it does assume that the soil would nevertheless be disposed of in a RCRA landfill. Case B assumes that the contaminated soil is a RCRA hazardous waste and is incinerated offsite.

The 28 refineries under the Case A assumption could incur an estimated one-time cost of about $2.67 billion. The five refineries in Group b could incur an estimated one-time costs of $710 million, about 27 percent of the total one-time costs.

The 28 refineries under the Case B assumption could incur an estimated one-time cost of about $7.54 billion. Again, the five refineries in Group b would be incurring about $2.00 billion in one-time cost.

The estimated incremental capital investments and one-time costs for Cases A and B by refineries groups are presented in Table 5-9. The net values (capital investment plus one-time Costs) by refinery groups are illustrated in Figure 5-10. The 28 refineries would be impacted for a total incremental net investment of about 2.97 billion per Case A and about $7.84 billion per Case B.

5.4.4 Contaminated Soil

The contaminated soil sensitivities sited in refineries include the Base Case and two other cases. The Base Case is closure in place (capping) of the contaminated soil in 187 refineries. NPC Survey data was utilized to estimate the quantity of contaminated soil in each of the nine refinery groupings.

Case A sensitivity allows for the removal of the contaminated soil. In this case the soil is assumed to be nonhazardous and placed in a RCRA type landfill. Case B is also a contaminated soil removal case. However, the soil is assumed to be hazardous waste and, therefore, it would be incinerated offsite.

The 187 refineries under the Base Case assumption could incur an estimated one-time cost of about $4.29 billion for closure in place operations. The 187 refineries under Case A assumption could incur an estimated incremental one-time cost of about $6.60 billion. The 24 refineries in Group f could incur an incremental one-time cost of $2.44 billion, about 37 percent of the total costs of $6.60 billion.

The 187 refineries under the Case B assumption could incur an incremental one-time cost of about $83.59 billion over the Base Case. The estimated incremental one-time costs and O&M expenses for the Base Case and Cases A and B by the refinery groups are presented in Table 5-10. The incremental one-time costs by refinery groups are illustrated in Figure 5-11.

Table 5-7

INCREMENTAL CAPITAL INVESTMENT, ONE-TIME COSTS, AND O&M EXPENSES FOR INACTIVE HAZARDOUS SWMUs

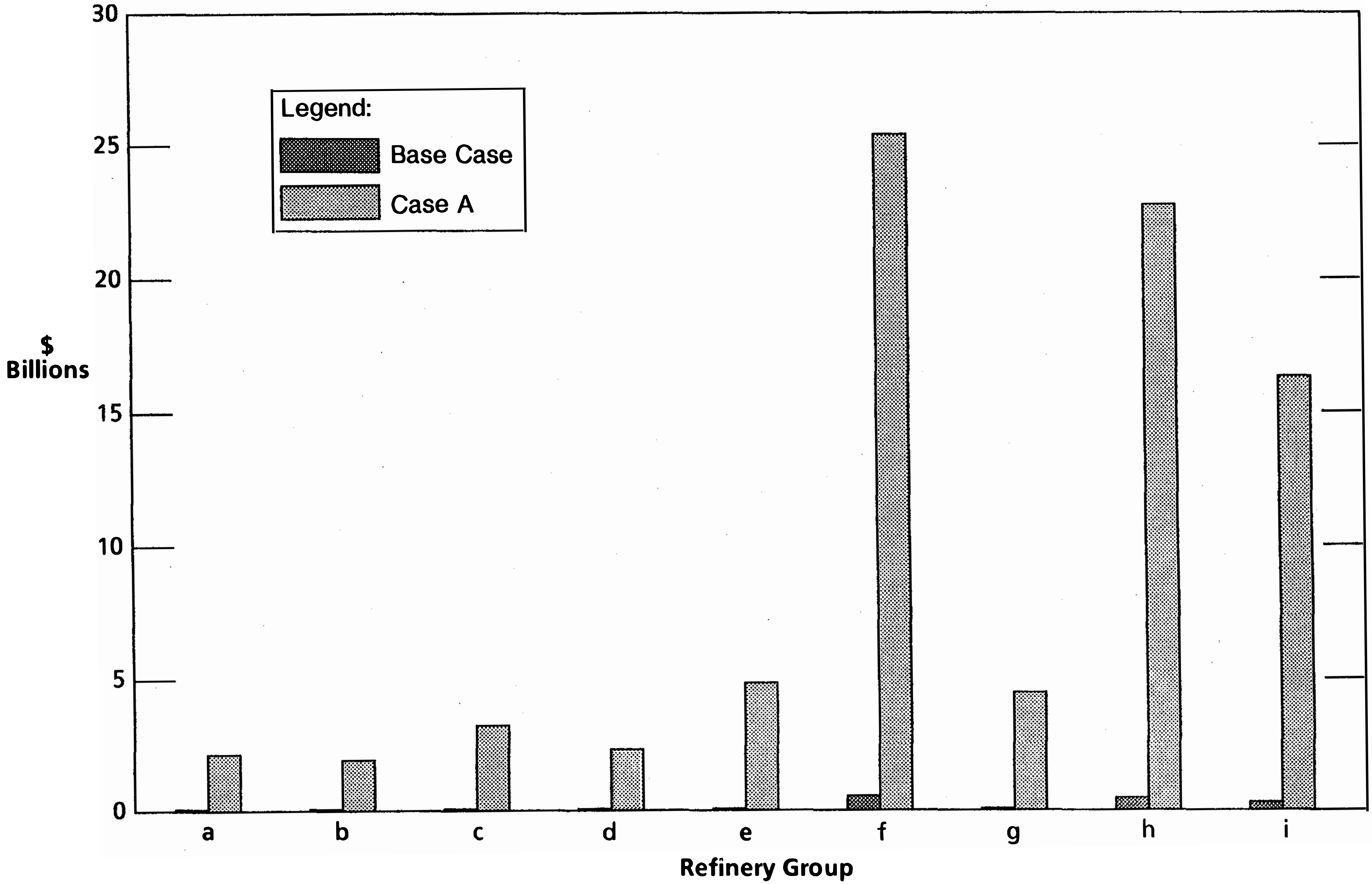
			$ Million	
Grouping	No. of Refineries	Item	Base Case	Case A
a	26	Capital	44	-44
		One-Time	0	2,159
		O&M	2	-2
b	24	Capital	41	-41
		One-Time	0	1,993
		O&M	1	-1
c	40	Capital	69	-69
		One-Time	0	3,322
		O&M	2	-2
d	28	Capital	48	-48
		One-Time	0	2,325
		O&M	2	-2
e	12	Capital	100	-100
		One-Time	0	4,983
		O&M	4	-4
f	14	Capital	515	-515
		One-Time	0	25,910
		O&M	19	-19
g	11	Capital	92	-92
		One-Time	0	4,568
		O&M	3	-3
h	14	Capital	461	-461
		One-Time	0	23,253
		O&M	17	-17
i	8	Capital	329	-329
		One-Time	0	16,609
		O&M	12	-12
Total	187	Capital	1,698	-1,698
		One-Time	0	85,121
		O&M	61	-61

Base Case: Closure of inactive hazardous SWMUs in place.
Case A: Removal of hazardous materials and incineration.

Note: Rows may not add due to rounding.

Figure 5-8

INCREMENTAL NET INVESTMENT VALUES FOR INACTIVE HAZARDOUS SWMUs



1092001-2

Table 5-8

INCREMENTAL CAPITAL INVESTMENT AND ONE-TIME COSTS FOR ACTIVE HAZARDOUS SWMUs

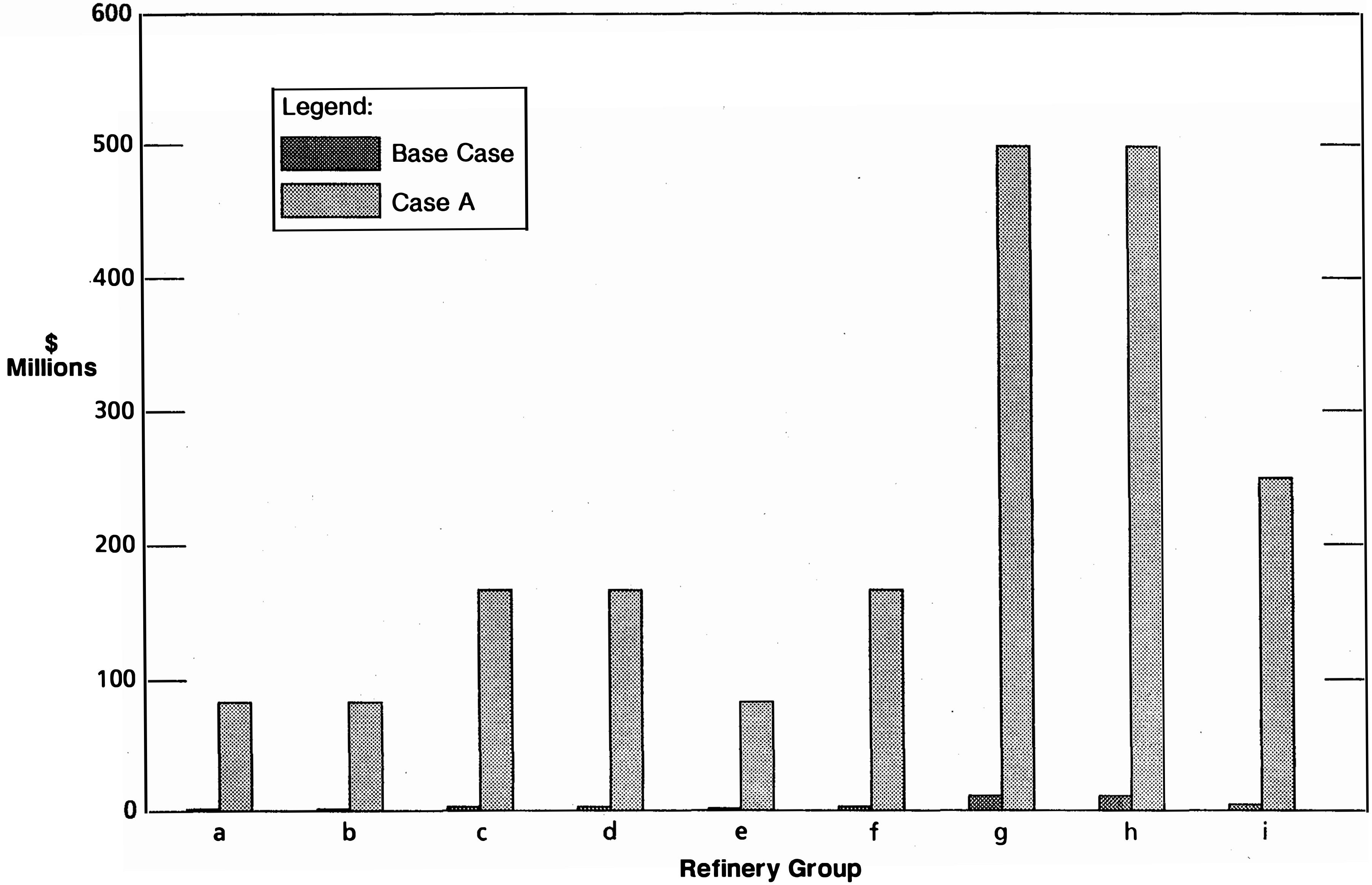
			$ Million	
Grouping	No. of Refineries	Item	Base Case	Case A
a	1	Capital	2	-2
		One-Time	0	83
b	1	Capital	2	-2
		One-Time	0	83
c	2	Capital	3	-3
		One-Time	0	166
d	2	Capital	3	-3
		One-Time	0	166
e	1	Capital	2	-2
		One-Time	0	83
f	2	Capital	4	-4
		One-Time	0	166
g	2	Capital	10	-10
		One-Time	0	498
h	2	Capital	10	-10
		One-Time	0	498
i	1	Capital	5	-5
		One-Time	0	249
Total	14	Capital	41	-41
		One-Time	0	1,992

Base Case: Closure of active hazardous SWMUs in place.
Case A: Removal of hazardous materials and incineration.

Note: Rows may not add due to rounding.

Figure 5-9

INCREMENTAL NET INVESTMENT VALUES FOR ACTIVE HAZARDOUS SWMUs



1092001-2

Table 5-9

INCREMENTAL CAPITAL INVESTMENT AND ONE-TIME COSTS FOR SURFACE IMPOUNDMENT RETROFIT

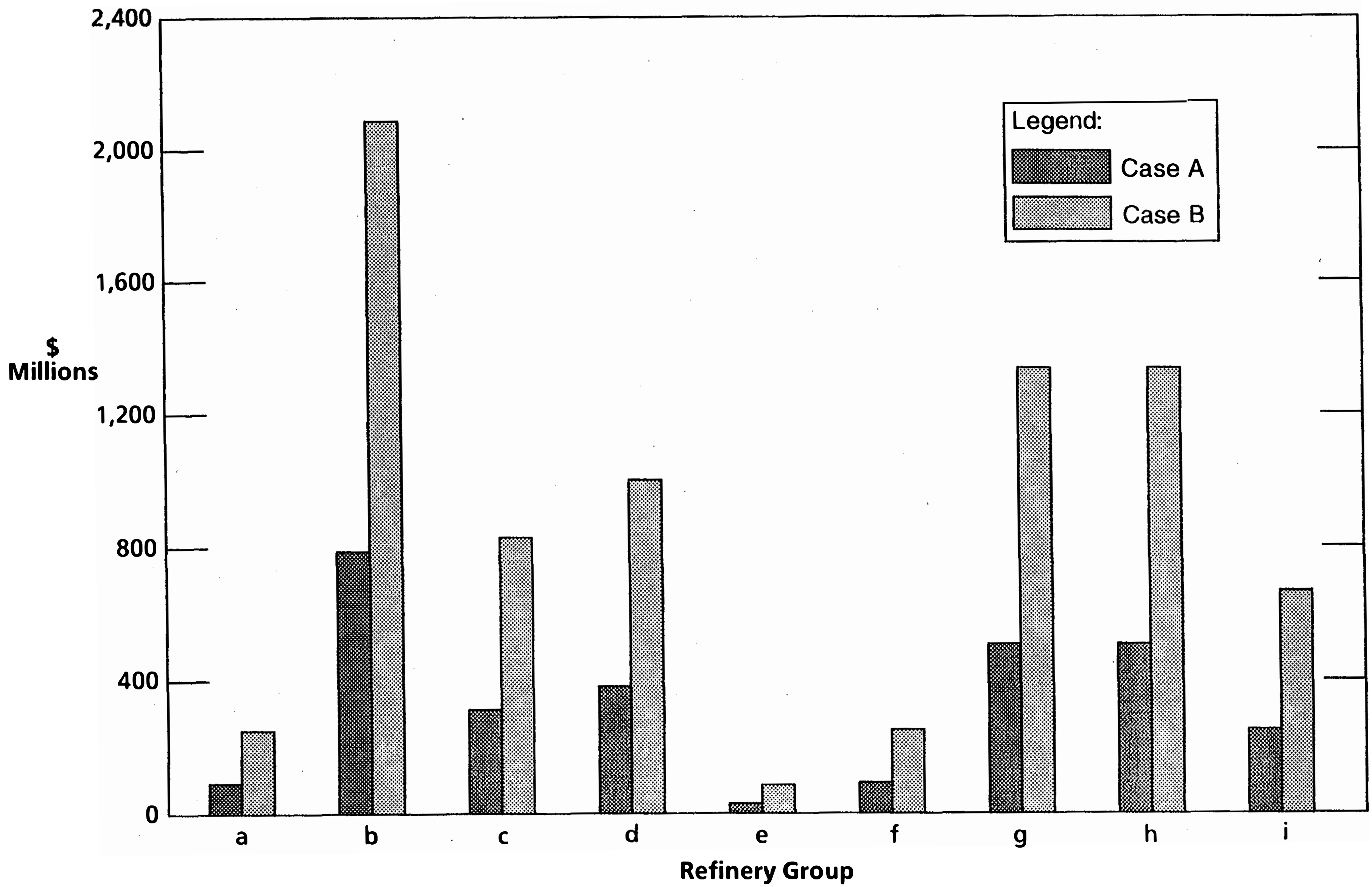
			$ Million	
Grouping	No. of Refineries	Item	Case A	Case B
a	3	Capital	9	9
		One-Time	85	241
b	5	Capital	78	78
		One-Time	711	2,005
c	5	Capital	32	32
		One-Time	284	802
d	2	Capital	38	38
		One-Time	341	962
e	1	Capital	3	3
		One-Time	28	80
f	3	Capital	10	10
		One-Time	85	241
g	2	Capital	52	52
		One-Time	455	1,283
h	2	Capital	52	52
		One-Time	455	1,283
i	1	Capital	26	26
		One-Time	227	642
Total	28	Capital	301	301
		One-Time	2,672	7,539

Base Case: No change
Case A: Retrofit (contaminated soil landfilled)
Case B: Retrofit (contaminated soil incinerated)

Note: Rows may not add due to rounding.

Figure 5-10

INCREMENTAL NET INVESTMENT VALUES FOR SURFACE IMPOUNDMENT RETROFIT



1092001-2

Table 5-10

INCREMENTAL ONE-TIME COSTS AND O&M EXPENSES FOR CONTAMINATED SOIL

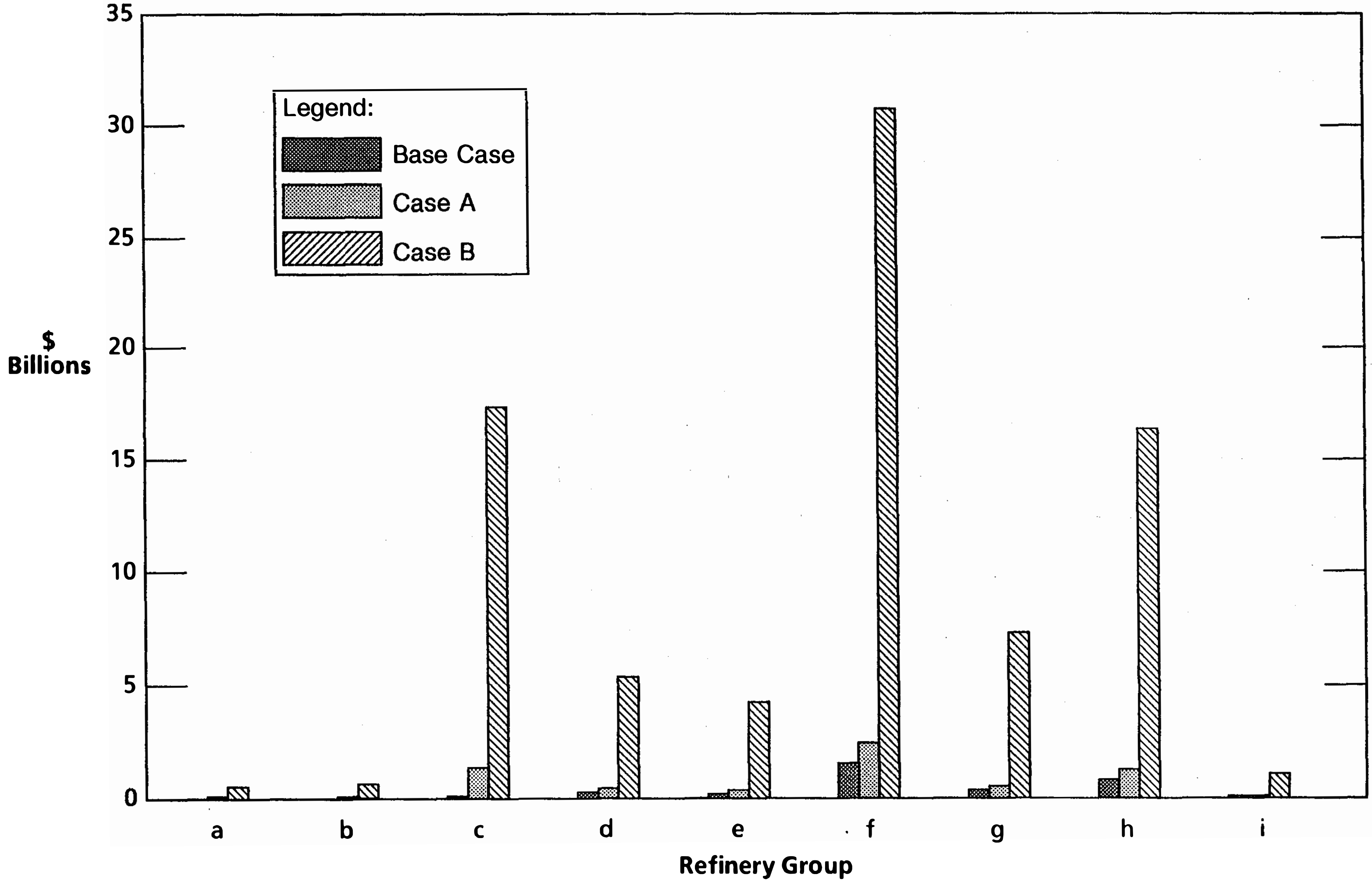
			$ Million		
Grouping	No. of Refineries	Item	Base Case	Case A	Case B
a	26	One-Time	31	77	623
		O&M	1	-1	-1
b	24	One-Time	32	80	647
		O&M	1	-1	-1
c	40	One-Time	897	2,252	18,217
		O&M	26	-26	-26
d	28	One-Time	277	695	5,621
		O&M	8	-8	-8
e	12	One-Time	220	551	4,458
		O&M	7	-7	-7
f	24	One-Time	1,576	4,012	32,338
		O&M	47	-47	-47
g	11	One-Time	376	944	7,636
		O&M	11	-11	-11
h	14	One-Time	831	2,143	17,214
		O&M	3	-3	-3
i	8	One-Time	56	139	1,127
		O&M	2	-2	-2
Total	187	One-Time	4,295	10,892	87,881
		O&M	105	-105	-105

Base Case: Closure in place
Case A: Removal (contaminated soil landfilled)
Case B: Removal (contaminated soil incinerated)

Note: Rows may not add due to rounding.

Figure 5-11

INCREMENTAL ONE-TIME
COSTS FOR CONTAMINATED SOIL



1092001-2

5.4.5 Light Hydrocarbon Storage Tank Replacement

The replacement of refinery light hydrocarbon tanks over 40 years old includes several sensitivity cases. The Base Case allows for only the replacement of one-half of the older tanks. Cases A and B include replacement of one-half of the older tanks and removal of contaminated soil from beneath the tanks. In Case A the contaminated soil is landfilled in a RCRA landfill. Case B includes the same activities as Case A; however, the contaminated soil removed is incinerated (50 percent onsite and 50 percent offsite). The number of total tanks in all the cases is based on the NPC Survey data.

The quantity of contaminated soil removed is calculated on the assumptions that approximately one-third of the tanks replaced have leaks in the tank bottom plate. Due to the leaks, approximately one-third of the area under the tank bottom is contaminated to a depth of six feet.

In the Base Case about $1.53 billion would be needed to replace aging light hydrocarbon tankage. The replacement tankage will be installed with double bottoms and double seals on either internal/external floaters. Dome roofs will be installed on 50 percent of the light hydrocarbon replacement tankage. The cost of the domes are assigned to the Air Sector.

In Case A, the tanks are replaced and contaminated soil under leaking tanks is removed and is landfilled in a RCRA landfill. The incremental one-time costs for handling the contaminated soil to a RCRA landfill site is estimated at $187 million.

In Case B, the tanks are replaced. Contaminated soil under leaking tanks is removed and incinerated. The incremental one-time cost for incinerating the contaminated soil is estimated at $868 million.

The estimated capital investment and one-time costs for the Base Case and Cases A and B by refinery groups are presented in Table 5-11.

The net values (capital investments plus one-time costs) by refinery groups are illustrated in Figure 5-12.

The 14 refineries in Groups f and h will incur an estimated $315 million and $332 million investment, respectively, for tankage replacement. Also, these 28 refineries could incur large one-time costs for treatment of the contaminant soil under the leaking tanks by incineration, $237 million and $205 million, respectively.

5.4.6 Heavy Hydrocarbon Storage Tank Replacement

The replacement of the heavy hydrocarbon tanks over 40 years old includes the same activities as light hydrocarbon tankage replacement. The Base Case is tank replacement only; Case A is tank replacement and contaminated soil removed to a RCRA landfill site; and Case B is tank replacement with soil removal and is incinerated - 50 percent onsite and 50 percent offsite.

The quantity of contaminated soil removed is calculated on the assumption that approximately one-third of the tanks replaced have leaks in the tank bottom plate. Furthermore, due to leaks, it is assumed that approximately one-third of the soil under the tank bottoms is contaminated to a depth of six feet.

Table 5-11

INCREMENTAL CAPITAL INVESTMENT AND ONE-TIME COSTS FOR LIGHT HYDROCARBON STORAGE TANKS REPLACEMENT

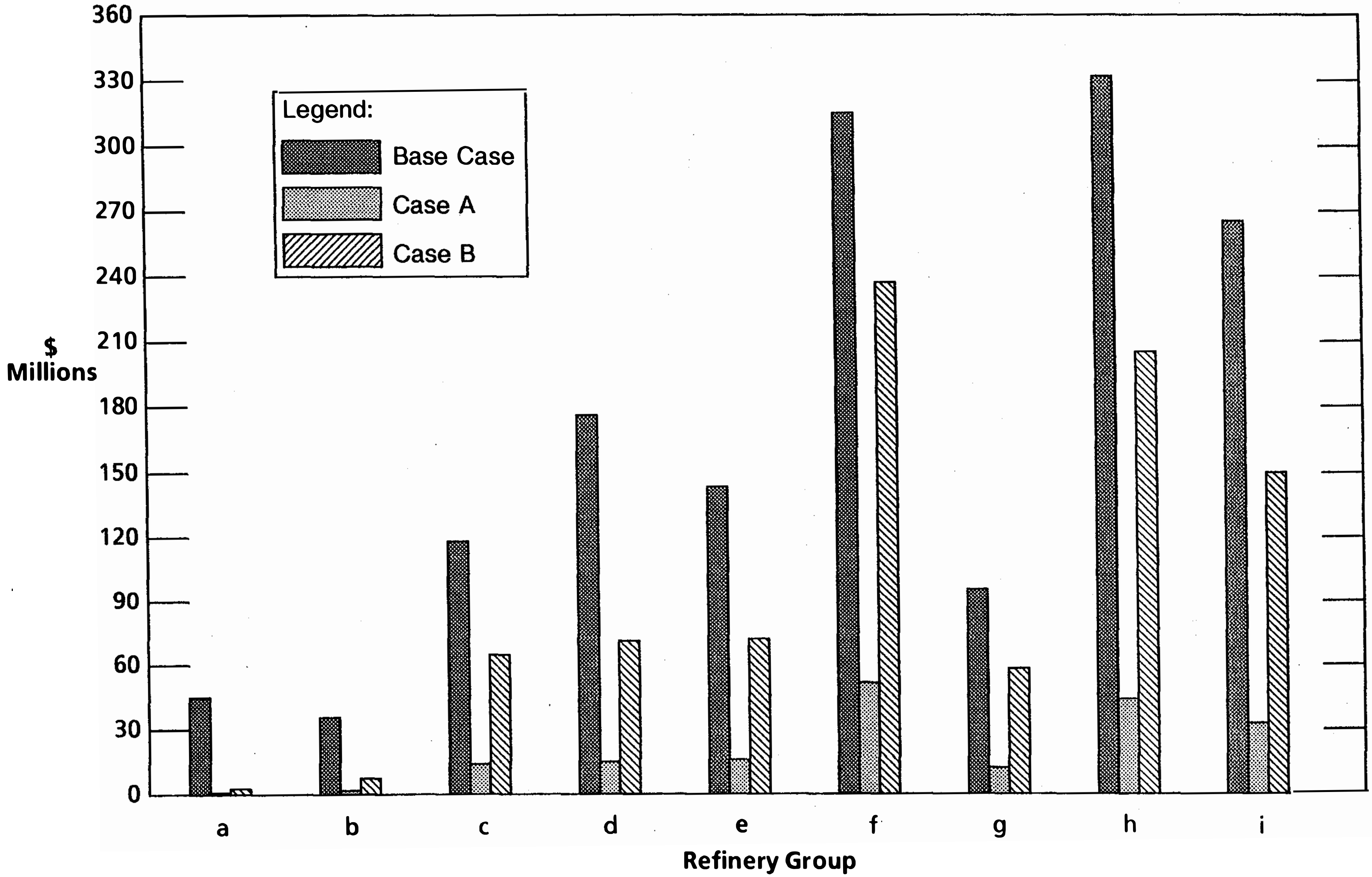
Grouping	No. of Refineries	Item	$ Million Base Case	$ Million Case A	$ Million Case B
a	26	Capital	45	0	0
		One-Time	0	< 1	3
b	24	Capital	35	0	0
		One-Time	0	2	7
c	40	Capital	118	0	0
		One-Time	0	14	64
d	28	Capital	176	0	0
		One-Time	0	15	71
e	12	Capital	144	0	0
		One-Time	0	16	72
f	14	Capital	315	0	0
		One-Time	0	51	237
g	11	Capital	96	0	0
		One-Time	0	13	59
h	14	Capital	332	0	0
		One-Time	0	44	205
i	8	Capital	265	0	0
		One-Time	0	32	150
Total	187	Capital	1,525	0	0
		One-Time	0	187	868

Base Case: Install replacement tanks
Case A: Install replacement tanks and remove contaminated soil (landfill)
Case B: Install replacement tanks and remove contaminated soil (incinerated)

Note: Rows may not add due to rounding.

Figure 5-12

INCREMENTAL NET INVESTMENT VALUES FOR LIGHT HYDROCARBON STORAGE TANKS REPLACEMENT



1092001-2

In the Base Case about $1.00 billion will be needed to replace aging heavy hydrocarbon tankage. The replacement tankage will have double bottoms.

In Case A, the tanks are replaced and the contaminated soil is removed to a RCRA landfill. The incremental one-time cost for handling the contaminated soil to a RCRA landfill site is estimated at $323 million.

In Case B, the tanks are replaced and the contaminated soil is removed and incinerated. The incremental one-time cost for incinerating the contaminated soil is estimated at $1.50 billion.

The estimated capital investment and one-time cost for the Base Case and Cases A and B by refinery group are presented in Table 5-12. The net values (capital investments plus one-time costs) by refinery group are illustrated in Figure 5-13.

Two refinery groups will incur the major share of the investment for storage tank replacement. The 14 refineries in Groups f and h will incur an estimated $236 million and $194 million investment, respectively, for tankage replacement. Also, these 28 refineries could incur large one-time cost for disposing of the contaminated soil from under the leaking tanks by incineration, $412 million and $425 million, respectively.

Table 5-12

**INCREMENTAL CAPITAL INVESTMENT
AND ONE-TIME COSTS
FOR HEAVY HYDROCARBON STORAGE TANKS REPLACEMENT**

			$ Million		
Grouping	**No. of Refineries**	**Item**	**Base Case**	**Case A**	**Case B**
a	26	Capital	39	0	0
		One-Time	0	1	4
b	24	Capital	21	0	0
		One-Time	0	2	8
c	40	Capital	98	0	0
		One-Time	0	20	92
d	28	Capital	89	0	0
		One-Time	0	14	64
e	12	Capital	68	0	0
		One-Time	0	18	83
f	14	Capital	236	0	0
		One-Time	0	89	412
g	11	Capital	55	0	0
		One-Time	0	19	88
h	14	Capital	194	0	0
		One-Time	0	92	425
i	8	Capital	201	0	0
		One-Time	0	69	321
Total	187	Capital	1,005	0	0
		One-Time	0	323	1,497

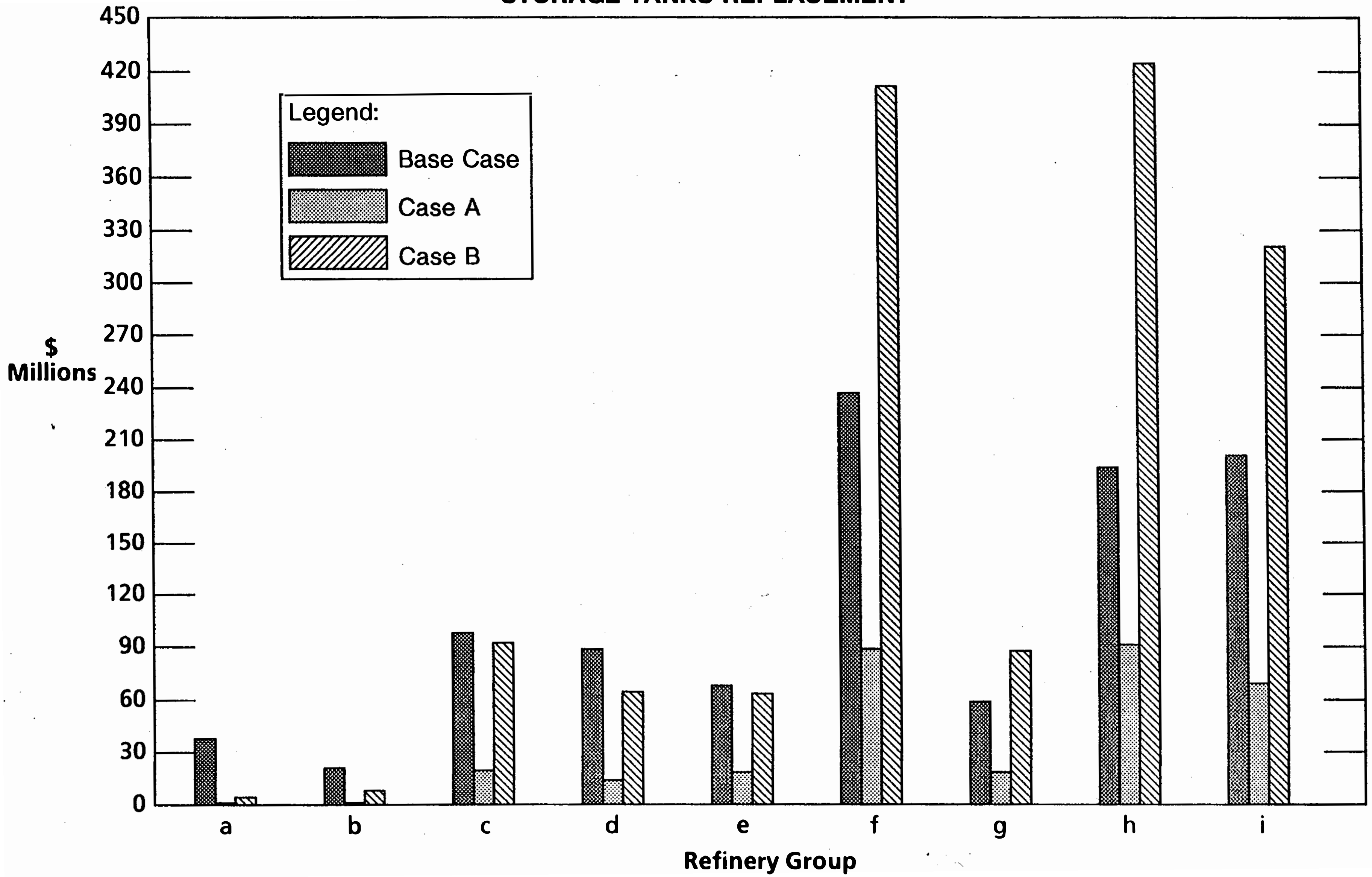
Base Case: Install replacement tanks
Case A: Install replacement tanks and remove contaminated soil (landfill)
Case B: Install replacement tanks and remove contaminated soil (incinerate)

Note: Rows may not add due to rounding.

5-38

Figure 5-13

INCREMENTAL NET INVESTMENT VALUES FOR HEAVY HYDROCARBONS STORAGE TANKS REPLACEMENT



1092001-2

6.0 SAFETY AND HEALTH SECTOR

6.0 SAFETY AND HEALTH SECTOR

New refinery safety and health programs being implemented during the 1990s and the first decade of the 21st century will be a product of Occupational Safety and Health Administration's (OSHA) "Process Safety Management" legislation as described in 29 CFR 1920.119 and the proposed regulations as required by the CAAA of 1990.

The incremental cost estimates for the U.S. refining industry to meet the NPC's premises on safety and health are:

	$ Million						
Item	1991-1995	1995	1996-2000	2000	2001-2010	2010	Total
Capital Investment	1,782	---	1,273	---	1,251	---	4,306
One-Time Costs	735	---	147	---	81	---	963
Total	2,517	---	1,420	---	1,332	---	5,269
O&M Expenses	---	58	---	178	---	178	---

Note: Costs are expressed in mid-1990 U. S. Gulf Coast dollars.

6.1 Premises

The premises proposed in this section of the report reflect the NPC and the petroleum industry perceptions of the potential EPA regulations for process safety and health. The NPC's premises are presented in Table 6-1.

Some of the anticipated EPA regulations and estimated cost impacts have a firm basis because of their similarity to existing OSHA regulations. In the NPC Survey, a significant number of refineries responded with actual cost figures for Process Safety Management (PSM) programs. Data are available that reflect cost incurred and anticipated future costs of compliance.

6.1.1 Regulatory Drivers

To establish the relationship between OSHA and EPA regulations, it will be necessary to explore the background of both agencies.

In response to mounting public concern over the mid-1980s Bhopal and Mexico City disasters and the possibility of such an occurrence in the United States, Congress passed the Emergency Planning and Community Right-To-Know Act in the fall 1986. This act is Title III of the Superfund Amendments and Reauthorization Act (SARA), and directs states, communities, and industry to work together to plan for chemical accidents, develop inventories of hazardous substances, track toxic chemical releases, and provide public access to information regarding hazardous substances.

Table 6-1

SAFETY AND HEALTH CONTROL TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject	Premises	Percent Implemented During 1991-95	1996-00	2001-10
Permit to construct and operate based on result of probabilistic risk assessment of potential community impact from hazardous materials release.	Likely, for new facilities by 2000. Not as likely for modifications to existing facilities. Harmful to industry if process to obtain permit Is lengthy.	25	75	0
Establishment of safety design requirements for refinery process computer control systems (redundancy levels, human factors considerations)	Moderately possible. Could involve significant limitations and restrictions.	100	0	0
Legislated phase out of materials regarded as highly hazardous (e.g., HF acid, chlorine, anhydrous ammonia) where suitable, less hazardous substitutes exist.	Likely over a period of time to allow for unit modifications. More likely for some materials than others.	0	50	50
Establishment of performance criteria for the handling of ceramic fiber/calcium silicate materials.	Very likely.	25	50	25
Establishment of training and company certification requirements for various levels of refinery operators.	Likely. Will probably start as required training specifications.	100	0	0
Establishment of requirements for the control of worker exposure to toxics.	Existing regulations may be interpreted in a stricter manner to incorporate MACT/BACT. It may be phased in via new construction only.	100	0	0
Establishment of requirements that person/organization (owner) which utilizes the services of a contract employee must provide training similar to that provided to owner employees.	The trend will likely continue with contract employees required to have a certain basic training supplemented by site-specific training.	100	0	0

O:\PROPOSAL\1093029\TABLE6

Table 6-1 (Cont'd)

SAFETY AND HEALTH CONTROL TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject	Premises	Percent Implemented During		
		1991-95	1996-00	2001-10
29 CFR 1910.119 Process Safety Management	Regulations currently under review.	100	0	0
Requirement for the development and maintenance of job toxic exposure profiles for job classification.	OSHA may present this as a record keeping requirement to document a healthy work place.	100	0	0
Residual Risk	Develop evaluation program.			

O:\PROPOSAL\1093029\TABLE6

Simultaneously, OSHA was reviewing their capability to inspect facilities that had the potential for "catastrophic releases" and to enforce existing regulations to prevent a Bhopal-type incident. In 1985, a release of aldicarb oxime and methylene chloride at a facility in Institute, West Virginia, injured 135 people and lent a further sense of urgency to the public and concerned agencies.

In late 1985, OSHA initiated a Special Emphasis Program for the Chemical Industry (Chem SEP). In 1987, OSHA issued its final report on the Chem SEP program. Among its findings were that "specification standards .... will not....ensure safety in the chemical industry .... (because such standards) tend to freeze technology and may minimize rather than maximize employer safety efforts." OSHA's report recommended a new approach to the identification and correction of potentially catastrophic situations.

Shortly after the OSHA report in late 1987, the EPA released a report. Among the findings in the EPA's June 1988 report was that "prevention of accidental releases requires a holistic (their term) approach that integrates technologies, procedures, and management practices." EPA also concluded that "a comprehensive approach to safety is dependent on management's commitment to the safe operation of the facility."

In November 1987, as a result of Chem SEP's findings, a task force was formed by Organization Resources Counselors (ORC) at OSHA's request. This task force developed a recommended approach for management of hazardous processes by defining the key elements of an effective management program and then incorporating the elements into recommended standards of practice.

"Recommendations for Process Hazards Management of Substances With Catastrophic Potential" was issued in December 1988. It is important to note that it had the full support of not only OSHA and the EPA, but the Chemical Manufacturing Association, API, and the American Institute of Chemical Engineers (AIChE).

These recommendations comprise a systematic approach to chemical process hazard management which ensures that the means for preventing catastrophic release, fire and explosion are understood and that the necessary preventive measures and lines of defense are installed and maintained. ORC's recommended systematic approach to process hazards management focuses on ensuring that sound engineering principles and practices are consistently used and applied.

In the Houston area, there were events (1989 and 1990) that resulted in catastrophic loss of life and received national attention. These events provided the necessary impetus for legislative action.

The API released a Recommended Practice, API RP 750, "Management of Process Hazards," in January 1990.

6.1.1.1 29 CFR 1910.119. In July 1990, OSHA published their proposed regulation, 29 CFR 1910.119, "Process Hazards Management of Highly Hazardous Chemicals." After the required hearings and response to public comments, it became law in May 1992.

The significance of these two events is that both documents followed closely the recommendations set forth in the 1988 ORC report.

The origin of the EPA's efforts in management of hazardous materials can be traced back to the 1970s when federal agencies began considering how to give workers access to information about the hazardous materials in their workplaces. After the Occupational Safety and Health Act passed in the early seventies, OSHA began work on a standard for chemical labeling in the workplace.

When the Toxic Substances Control Act (TSCA) passed in 1976, an EPA task force began to study how labels and material safety data sheets (MSDSs) might be used to communicate chemical hazards to workers. In 1978 OSHA took responsibility for workplace hazard communication, and in 1983 OSHA issued the Hazard Communication Standard.

Lobbying efforts led to 15 state right-to-know laws by the end of 1983, and two states, New Jersey and Massachusetts, included requirements for information disclosure to the general public in their laws. By 1986, there were 41 states with right-to-know provisions, 25 with community/emergency response requirements.

In 1985, in the absence of comprehensive federal legislation on community right-to-know and emergency response, the EPA developed the Chemical Emergency Preparedness Program. The agency distributed the first part of the voluntary program to states in November 1985. The program included guidelines on organizing community emergency preparedness, site-specific emergency planning, criteria for determining whether a substance is hazardous, and profiles of hazardous substances. EPA also issued a list of 402 "extremely hazardous substances" under the program.

Meanwhile, the 1985 U.S. congressional session began debating community right-to-know and emergency response legislation, and in July 1986, a Congressional Conference Committee reached a compromise on federal community right-to-know and emergency planning requirements. On October 17, 1986, President Ronald Reagan signed into law the Emergency Planning and Community Right-To-Know Act, otherwise known as Title III of the Superfund Amendments and Reauthorization Act (SARA Title III).

SARA Title III uses two primary methods to protect the public from hazardous chemical releases and accidents: it grants access to information on hazardous chemical processes; and imposes legal responsibilities on public agencies and industry.

6.1.1.2 Clean Air Acts Amendment 1990, Title III. The CAAA of 1990 represents the newest and most comprehensive legislation to date. This study will focus on Section 301 of Title III of the CAAA. Section 301 covers Hazardous Air Pollutants and Accident Prevention, and contains complex and far-reaching air toxics prevention measures.

Section 301 of Title III amends Section 112 of the CAAA on NESHAP, completely revising and greatly expanding on earlier approaches. It contains four major provisions:

1. It lists 189 HAPs and directs the EPA to identify the industries that emit them.

2. It requires stringent MACT standards to reduce present levels of HAP emissions.

3. It provides a framework for even more stringent residual risk standards to protect health and the environment.

4. It authorizes the establishment of regulations and programs to prevent and minimize the consequences of accidental releases of Extremely Hazardous Substances (EHS).

6.1.1.3 Anticipated "Risk Management Plan" Requirements. Section 301 of Title III, which adds a new subsection (r) to Section 112 of the CAAA, emphasizes measures that eliminate or mitigate potential hazards associated with accidental releases.

The subsection implements four major initiatives aimed at chemical identification, accident investigation, prevention planning, and enforcement. These initiatives are:

1. Characterizing EHS and establishing threshold limits.

2. Creating an independent Chemical Safety and Hazard Investigation Board (CSB).

3. Requiring mandatory Risk Management Plans (RMPs) that include Hazard Assessment (HAs) for sources that produce, process, handle, or store ESHs.

4. Imposing legal obligations to compel facilities to operate in a manner "to prevent releases and to mitigate releases which do occur."

The first initiative is underway and will continue for several years. It is highly doubtful that any refinery will escape the EPA requirements. It is important to understand the CSB role in management of hazardous processes so that the comparisons between existing OSHA regulations and future EPA regulations can be established.

The CSB will investigate accidental releases in a manner similar to the National Transportation Safety Board (NTSB) investigation procedures. The CSB will also study hazards associated with EHSs and will assist in developing EPA protocols.

The CSB has mandated to it by law the responsibility to define the materials of interest and help establish threshold quantities of concern. It must also develop protocols for performing HAs and to report on these and other issues to Congress, the EPA, OSHA, and other federal, state, and local agencies.

In addition, the CSB has been directed to establish accident reporting requirements for affected facilities.

The CSB is charged with issuing a report to EPA and OSHA by late 1992, recommending the adoption of regulations for RMPs at affected facilities. The EPA has been charged with promulgating RMP regulations by late 1993.

Some of the issues that Section 112(r) requires the EPA to include in its accident prevention program are:

- Hazard Assessment - Quantitative and qualitative techniques for determining the events that could cause an accidental release, determination of downwind effects, previous release history, and worst case potential.

- Release Prevention - Systems which reduce the probability that the primary containment will be breached or reduce the potential magnitude of a release via process changes, controls, or reduction in substance quantity or potency.

- Emergency Response Planning - Actions to be taken in the event of an accidental release such as mitigation measures, public and local agency notification, emergency health care, and employee training.

- Risk Management Plan Registration - The above elements are to be incorporated into a formal RPM which will be filed with the EPA, CSB, and any state or local agency that is responsible for planning or responding to accidental releases.

To establish the basis for comparing the actual costs of ongoing PSM costs incurred under OSHA with future EPA regulations, it is necessary to define clearly what congress's intent was when they provided the precise wording in the CAAA of 1990.

The act specifically requires each facility that produces, processes, handles, or stores listed EHSs above the defined threshold quantities to conduct and make available a HA.

The HA must identify equipment and/or processes that may fail, the magnitude of potential releases, and their possible impacts on persons and property. The HA must also indicate the probability associated with each of several likely outcomes, including the "worst-case scenario."

The HA must be conducted in accordance with EPA guidelines. These guidelines will cover specific methodologies, techniques, parameters, and assumptions, as well as modeling requirements for simulating the behavior of vapor and liquid/vapor releases.

Specific requirements according to congressional reports are:

- Basic data on the facility units which contain or process EHSs, facility operating procedures, population of nearby communities, and the meteorology of the area where the facility is located

- Potential sources of sudden, accidental releases of EHSs

- Any previous releases for which a report was required under this or other laws, including the amounts released, frequencies, and durations

- A range (including worse case events) of potential releases including an estimate of release size, concentration, and duration and a correlation of these factors with the distance from the source of release

- Potential exposure (including the concentration and duration of exposure) for all persons who may be put at risk as a result of a sudden, accidental release from the facility

- The probability of exposure using various release scenarios and including meteorological factors

- Information about the toxicity of the EHSs at the facility

- A review of the effectiveness of release prevention measures, including process changes or material substitutions

6.2 Process Safety Management (PSM) Related Costs

In 29 CFR 1910.119, OSHA defined their expectations relative to an acceptable PSM program. In the preamble contained in the *Federal Register*, dated February 24, 1992, OSHA outlines their concept of PSM program content. In addition, OSHA Notice CPL 2, dated March 9, 1992, provides policies and procedures for inspections under the Special Emphasis Program (PETROSEP) in petrochemical industries, including SIC code 2911 -- Petroleum Refining.
An examination of those documents and the CAAA requirements discussed above indicate that the EPA intends to follow closely the recommendations as outlined by ORC in their 1988 report.

These PSM procedures are also closely aligned with the AIChE Center for Chemical Process Safety (CCPS) recommendations contained in several publications, including *Technical Management of Chemical Process Safety*.

Based on the similarities between existing OSHA regulations and anticipated EPA regulations, the assumption was made that refiner's perceptions of how to design and implement a PSM program to comply with OSHA regulations would be similar to EPA RMP requirements.

A significant number of refiner's have already undertaken a PSM program to comply with OSHA's PSM regulations. This cost (actual and anticipated) is reflected in several of the responses of the NPC Survey questions.

The 154 respondents to NPC survey Section II represents approximately 90 percent of U.S. total crude capacity. Because of that number, cost data were extended as though total U.S. refining capacity were represented by the survey results.

Cost estimates in the safety and health section represent a best effort based on the general nature of the NPC Survey questions, speculative premises, and uncertainties associated with limited data.

Trying to determine the full impact of new environmental regulations and separating the cost of complying with existing OSHA PSM requirements from those of upcoming RMP regulations present difficulties that would entail much more than an examination of potential expenditures and is beyond the scope of this study.

For example, under OSHAs 29 CFR 1910.119, almost all of the process safety procedures likely to be required under the EPAs CAAA, Section 301 of Title III, Section 112, RMP permit procedures, will have been done before the EPA regulations are promulgated.

For these reasons, aggregate estimates should be treated as approximations.

6.2.1 Process Hazards Analysis

One question in the NPC Survey addresses the issue of Process Hazards Analyses (PHA). It asks refiners to provide data on:

- Number of units for which PHAs are complete
- Percentage of total corrective action completed or resolved
- Total expenditures for corrective actions completed or resolved
- Total budget for remaining corrective actions

6.2.2 Operations and Maintenance Expenses

Other NPC Survey questions asked refiners what their facility's projected operations, and maintenance expenses for 1995 were expected to be, and what their total one-time expenses and total capital expenditures during the five-year period from January 1, 1991, through December 31, 1995, were expected to be as a result of regulations and approved legislation as of December 31, 1990. They were asked to include expenditures resulting from the CAAA of 1990 and expected regulations from those amendments.

Costs related to process safety management expended in response to API RP 750 or other state and federal process safety requirements were to be included in this estimate. The numbers submitted by those respondents appear to provide a more reliable picture of the actual cost to refiners than earlier studies.

Eighty-eight refineries responded to this question. They estimated that 1995 O&M expenses would be $144 million. If the other 99 refineries experience similar expenditures, anticipated 1995 total O&M expenses will be in the range of $295 million.

6.2.3 One-Time Expenses

The survey also requested data on one-time expenses for process safety-related issues associated with capital projects and one-time remediation activities. Eighty-one refineries responded with data and reported they will spend $346 million during the 1991 through 1995 time period. If that number is extended to include the 106 refiners who did not respond, total one-time expenses could be expected to be in the $770 million range.

6.2.4 Capital Expenditures

Total capital expenditures anticipated for the period January 1, 1991, through December 31, 1995, by 101 refiners who responded were $1,005 million. Using the same rationale previously mentioned, it is projected that the remaining 86 refineries will bring the total amount of capital expenditures to $1,764 million.

6.2.5 Training Costs

Training costs were not broken out in the Survey. It is reasonable to assume, however that refiners would include those anticipated costs in their responses because of the training requirements under 29 CFR 1910.119.

6.3 Costs of PHAs Already Completed

Sixty-four refineries responded to NPC Survey question of "Percentage of Total Corrective Action Completed or Resolved."

6.3.1 Units Completed

The 64 refineries indicated that the NPC 223 units have had the necessary PHAs completed. It is not possible to determine from the NPC Survey data what percentage of total refinery units may have been examined and found to not require corrective action, or for example, been prioritized lower on the list so that corrective action will be determined at a later date.

Because 29 CFR 1910.119 specifically requires that some sort of PHA be done to allow identification and prioritization of hazards for further analysis, it is reasonable to assume that the 64 respondents did do a PHA and have concentrated their resources on the most serious potential hazards first and undertaken the required corrective actions. Using this rationale, it was assumed that the remaining 123 refineries will experience a similar cost impact proportional to their size and complexity when they complete their PHAs.

6.3.2 Corrective Actions Completed

Of those 64 refineries with PHA programs, 40.6 percent of the corrective actions identified by the PHAs have been completed or resolved.

6.3.3 Total Expenditures for Corrective Actions

In response to the question of total expenditures for corrective actions completed or resolved, 57 refineries responded. The total expenditure was $111 million.

6.3.4 Remaining Budgets for Corrective Actions

The total budget remaining to complete corrective actions as identified by 54 refineries would be $318 million.

The percentage of responders was relatively low. However, considering that 29 CFR 1910.119 did not become law until May 1992, and API RP 750 is a recommended practice, it is not particularly surprising that only 56 to 64 of the refiners are far enough along in their process safety management program to have meaningful data.

The number of responders to the questions would seem to indicate that although a number of refiners have not yet accumulated sufficient cost data on PHAs and their resolution to provide input to the survey, they are aware of the PSM implications and are developing budgets to address those issues.

6.4 Expected Impact of OSHA and EPA Requirements

OSHAs new Process Safety Management Regulation, 29 CFR 1910.119, became law in May, 1992. Because the draft was issued for public comment July 1990, refiners have been aware of impending PSM regulations for some time. In addition, API RP 750 was issued in January, 1990, the ORC Report in December 1988, and each of these provided guidance for a PSM program.

Given the mandated deadlines for compliance with OSHA and EPA regulations and the legal maneuvering already taking place by both organized labor and industry, only mandated dates will be considered. Actual compliance dates may vary considerably based on results of decisions rendered by both government agencies and courts.

It is anticipated that the majority of compliance costs for PSM programs will be incurred during the 1991 through 1995 time period. Although many of the EPA requirements for control of accidental releases of hazardous materials has yet to be mandated, all indications are that the same issues identified by the ORC in its 1988 report and used by AIChE CCPS, API, and OSHA in their process safety management programs will be used by the EPA.

The petroleum refining industry must complete all process hazard analysis by May 26, 1997. Given the requirement to prioritize and correct the most hazardous situations first, projections are that most expenditures will occur in the 1991 through 1995 time period.

Some of the premises that appear to have a strong movement toward legislation, phase-out of hazardous materials, and regulation of man-made vitreous fibers, for example, have their implementation spread out over a longer time period, 1991 through 2010.

Because of the expected similarity of pending EPA regulations regarding control of accidental releases of hazardous chemicals to OSHAs PSM regulations, it seems reasonable to assume that the petroleum refining industry will have already incurred the majority of the cost of compliance to meet OSHAs PSM program and will require relatively minor adjustments to meet any additional measures required by the EPA to meet their RMP requirements.

6.5 Safety and Health Premises for Determining Cost of Compliance

There are nine premises used to establish the basis for estimating the future cost of complying with federal regulations dealing with process safety and health.

Using the nine groupings of refineries, the nine premises have investments and/or O&M expenses developed as: capital investment, O&M expense, and one-time expenses, respectively.

Following is a description of the nine premise, rationale and methodology for determining investment and/or O&M expenses.

6.5.1 Requirement to Perform Probabilistic Risk Assessment of Potential Community Impact from an Accidental Release of a Hazardous Material (Construction/Operating Permit)

Based on the existing information available from the EPA, their concept of HAs and RMPs that must be executed will require a probabilistic risk assessment when submitting construction/operating applications to OSHA and EPA.

An estimate for such an activity was made using the procedures outlined in the *AIChE CCPS Manuals, Technical Management of Chemical Process Safety, Hazard Evaluation Procedures, Chemical Process Quantitative Risk Analysis,* and 29 CFR 1910.119, *Process Safety Management of Highly Hazardous Chemicals*.

One-time costs include the costs to develop the basic process safety information consisting of MSDSs, process description, conduct preliminary hazard analysis, and process hazard analysis, (including gas dispersion modeling and risk probability analysis), develop operating procedures, mechanical integrity procedures, hot work permit procedures, management of change procedures and emergency response plans, including community action plans. The estimated one-time costs also includes preparation of the permit application.

Capital investments and O&M expenses were considered to be relatively insignificant.

6.5.2 Establish Safety Design Requirements for Refinery Process Computer Control Systems (Process Control Safety Systems)

A national consensus standard for microprocessor-based *Safety Systems* does not exist at this time. The Instrument Society of America (ISA) has a committee, SP-84 that is developing a standard. It is now in its seventh draft.

The AIChE CCPS has a publication *Safe Automation* that describes the theory and relationship between plant DCS and microprocessor-based safety systems. In addition, API RP 750, references API RP 14C which provides a basis for safety systems.

Refineries are installing microprocessor-based independent, redundant, safety systems at this time. An estimate was made based on actual data from engineering/construction projects on the Gulf Coast.

The data for actual projects was prorated among various sized facilities by determining the types of units involved and estimating differences in size and complexity of the safety system. One-time costs are defined as the costs to remove conventional ESDs or emergency shutdown systems to allow installation of modern microprocessor-based safety systems.

Typically, existing systems may be manual or automatic pneumatic, electric, hard-wired relay, part of a conventional DCS or some combination configuration. Capital investment are considered to be the cost of hardware, software, and installation, including field devices and routing.

O&M expense 15 based on NPC Survey data from refinery response and are annualized to reflect only 1995 projected costs.

6.5.3 Legislated Phase-Out of Materials Regarded as Highly Hazardous Where Suitable, Less Hazardous Substitutes Exist (Phase-Out Hazardous Materials)

Hydrogen Fluoride (HF) acid alkylation units were chosen as the test case because of legislative activity in that area and the availability of information regarding an acceptable substitute process.

An estimate was made to replace HF acid alkylation units with Sulfuric (H_2SO_4) acid alkylation units. The 187 refineries were examined to determine where HF units are presently being used, if so, costs to demolish the HF unit and construct a new H_2SO_4 unit were made using conventional estimating methods.

One-time costs consist of the expense to dismantle an existing HF unit from a plant site. For estimating purposes, no environmental clean up activities were included. Capital investment for a replacement H_2SO_4 acid alkylation unit includes engineering design, procurement, and construction costs.

O&M expenses include incremental O&M expenses associated with an H_2SO_4 acid unit versus HF acid unit as well as costs to regenerate spent H_2SO_4 acid.

6.5.4 Establish Performance Criteria for the Handling of Ceramic Fiber/Calcium Silicate Materials

Calcium silicate was chosen as a possible candidate for future regulation with the greatest potential cost impact. An estimate was made using data from a public source report on capital spending.

One-time costs are defined as the expenses to remove the calcium silicate (typically used as a low cost energy insulator). Cost to dispose of the calcium silicate once removed, are not included.

Capital investments include costs of material and labor to install a material similar in insulating characteristics and cost to calcium silicate. No attempt was made to identify or quantify this "new" insulating material. O&M expenses were derived from the public source data with adjustments for plant size and complexity.

6.5.5 Establish Training and Company Certification Requirements for Various Levels of Refinery Operators (Operator Training and Certification)

This premise is supported by requirements under 29 CFR 1910.119 regarding training of operators and its provision that allows companies to certify experienced operators in lieu of going through initial training sessions. The next step is expected to be certification of all operators to ensure a level of comprehension and performance.

The assumption is made that training and certification will be carried out on a local (company) level (i.e., no federal or state sponsored training or tests required).

The refinery operator population was separated into two groups. One group, representing 50 percent of total population, was categorized as "B" (entry level operators), the second group was categorized as "A" (lead operators).

Estimates to develop training programs for entry level operators and lead operators were made based on actual programs in place. One-time costs are the expenses associated with development of training programs. This includes costs such as personnel to develop the program, cost of material, and training manuals.

Capital investments were not considered significant because it was assumed that equipment and facilities already exists at the refineries. O&M expenses are expected to consist of up grading of existing programs and continual refresher training and advanced training for "B" operators to allow them to move into "A" operator slots.

6.5.6 Establish Requirements for the Control of Worker Exposure to Toxics (Controlling Worker Exposure)

Section 112(f) of the CAAA will protect human health and the environment beyond MACT standards. Often called residual risk provisions, the intent is to control HAP emissions beyond the level required by MACT, perhaps based on risk assessments.

This premise makes the assumption that this requirement would result in a higher level of safety analysis and control to protect workers than would be required under existing legislation.

For example, the EPA has been directed to establish further standards to reduce the lifetime excess cancer risk to less than one-in-one million for sources that emit known, probable or possible human carcinogens.

Costs were estimated to do a detailed preliminary hazard analysis to identify potential areas where exposure might exceed acceptable levels, perform a detailed consequence analysis to determine severity and probability levels, and provide safety systems (gas monitoring, shutdown, water spray, vapor gathering, etc.) that would be used to detect and control/mitigate the exposure if it were to occur.

One-time costs were estimated to be the expenses associated with performing the safety analysis work. Refinery processing facilities were broken down by size and configuration to estimate the magnitude of the analysis work.

Capital investments consist of the safety systems that would be required to ensure that exposure levels would not exceed established limits as defined by the EPA. O&M expenses consist of typical costs to service the process safety systems.

6.5.7 Establish Requirements that Person/Organization (Owner) Which Utilizes the Services of a Contract Employee Must Provide Training Similar to that Provided to Owner Employees (Contractor Training)

The basis for the estimate was that safety orientation training, unit specific hazards, and plant safety rules would be conducted by the owner, but actual job specific and craft training programs would still be the responsibility of the contract employer.

The estimated staffing requirements for each of the nine refineries groupings were used to determine the number of contract employees in a plant at a given time. No accounting was made of the number of contract employees in a given plant during shutdown/turnaround periods.

One-time costs consist of the expenses to develop the training program similar to Section 6.5.5. Capital investments are considered insignificant because existing facilities and equipment are assumed to be available. O&M expenses include estimated costs to up date the programs and conduct classes on an as-needed basis.

6.5.8 Meeting 29 CFR 1910.119 Process Safety Management Program Requirements (PSM)

NPC Survey data were used for identifying PSM costs. Fifty-seven refineries responded with cost data.

Although only 173 process units were involved in the survey response, 29 CFR 1910.119 requires that a PHA be done to identify hazards and to prioritize further studies and analysis. It was assumed that this process had been completed for the respondents. Given that priorities had been established, then the units perceived as more hazardous and in need of corrective action had been identified and corrective actions undertaken.

It was therefore assumed that the 57 refineries that did respond, the major expenses have been incurred and other 130 refiners would have similar experiences.

In absence of other data, it is proposed that the responders represent a crossview of the general population and that expenditures (actual and anticipated) provided a far more accurate picture of PSM costs than other available data.

PSM training was also identified. In that category, estimated costs reflect only those items that would be covered under general safety orientation training, unit specific hazards, and plant safety rules.

One-time costs consist of conducting the analysis necessary to comply with 29 CFR 1910.119. Typically, this would consist of PHA, consequence analysis, generation of required safety information, HAZOPS, and development of procedures to ensure compliance.

Training costs were identified as described in Sections 6.5.5 and 6.5.7.

Capital investments would consist of the corrective actions taken to correct hazardous conditions as identified by the analysis discussed above. This would include engineering design, demolition, and construction where needed.

Capital investments for PSM training were considered insignificant.

O&M expenses are considered insignificant for conducting PHAs and corrective actions.

PSM training was estimated based on the same factors as in Section 6.5.7.

6.5.9 Require the Development and Maintenance of Job Toxic Exposure Profiles for Job Classification (Toxic Exposure)

The requirement to develop toxic profiles on employees would require development of job specific procedures, initial monitoring, ongoing personnel monitoring, establishment of employee health profiles, and the development of medical histories that would allow diagnosis, etiology, and prognosis of almost any conceivable health problem to determine if it was work related and the steps necessary to protect the health of the employee.

One-time costs consist of the initial analysis work done to identify where job duties might expose employees. Included in one-time costs are the development of measurement procedures, test criteria, and program set-up procedures. This would include the costs of the medical program to establish a baseline for medical history.

Capital investments would include the costs of designing and installing monitoring hardware based on refinery size and type of processing units involved.

O&M expenses consist of the annual costs to monitor the work environment, maintain monitoring equipment, and provide an ongoing medical history for each employee who has any exposure to toxic materials.

6.6 Summary

6.6.1 Incremental Capital Investment

The estimated incremental capital investment for control systems and programs to meet process safety and health regulations, the U.S. refining industry could be spending $4,306 million (mid-1990 U.S. Gulf Coast) during the 1991 through 2010 time period. The investments will be spread over three areas as indicated below:

Item	$ Million	Percent
Phase-out Hazardous Materials (HF)	2,457	57.0
PSM Programs	1,473	34.3
Others	374	8.7

Table 6-2 presents the details on what process safety and health control technologies the investments are being spent on and the time periods being covered.

The majority of the $4,306 million is estimated to be spent in the 1991 through 1995 time frame as indicated by the data listed below:

Period	$ Million	Percent
1991-1995	1,782	41.4
1996-2000	1,273	29.6
2001-2010	1,251	29.0

Table 6-2

SAFETY AND HEALTH TECHNOLOGY COSTS
INCREMENTAL CAPITAL INVESTMENT
ALL REFINERY GROUPS
($ MILLION)

	Implementation Period			
	91-95	96-00	01-10	Total
Construction/Operating Permit	0	0	0	0
Process Control Safety Systems (ESDs)	170	0	0	170
Phase-out Hazardous Materials (HF)	0	1,229	1,229	2,457
Regulation of Ceramic Fiber and Calcium Silicate	23	45	23	90
Operator Training and Certification				
Initial Training	0	0	0	0
Update Training	0	0	0	0
Subtotal	0	0	0	0
Controlling Worker Exposure	71	0	0	71
Contractor Training	0	0	0	0
PSM				
PSM Program	1,475	0	0	1,475
PSM Related Training	0	0	0	0
Subtotal	1,475	0	0	1,475
Toxic Exposure	43	0	0	43
All Refinery Groups Incremental Capital Investment	1,782	1,274	1,251	4,306

Note: Columns and rows may not add up due to rounding.

The major area of process safety and health investment during the 1991 through 1995 time frame will be made on PSM programs. The phase-out of hazardous materials - replacement of HF acid alkylation units with H_2SO_4 acid alkylation units - may occur in the 1996 through 2010 time frame.

The investment for the replacement of the HF acid alkylation units account for the major portion of the investment during the two time periods of 1996 through 2000 and 2001 through 2010.

Capital Investment for process safety and health control technologies per refinery per group are presented in Table 6-3 and illustrated in Figure 6-1. Capital investment dominates in the 1991 through 1995 period for refineries in Groups f, g, k, and i, mainly to install PSM programs.

6.6.2 Incremental One-Time Costs

The estimated incremental one-time costs for control systems and programs to many process safety and health regulations, the U.S. refining industry could be spending $963 million (mid-1990 U.S. Gulf Coast). The one-time costs will be spread over four areas as indicated below:

Item	$ Million	Percent
PSM Programs & Training	345	35.9
Phase-out Hazardous Materials (HF)	162	16.8
Controlling Worker Exposure	159	16.5
Others	297	30.8

Table 6-4 presents the details on what process safety and health control technologies and programs the one-time costs are being made.

One-time costs for process safety and health control technologies and programs for refinery per group are presented in Table 6-5. The costs are rather minor for a refinery and the one-time costs cover a number of programs.

6.6.3 Incremental Operating and Maintenance (O&M) Expenses

The estimated incremental O&M expenses for the process safety and health control devices and programs for the three time periods are:

Year	$ Million
1995	58
2000	178
2010	178

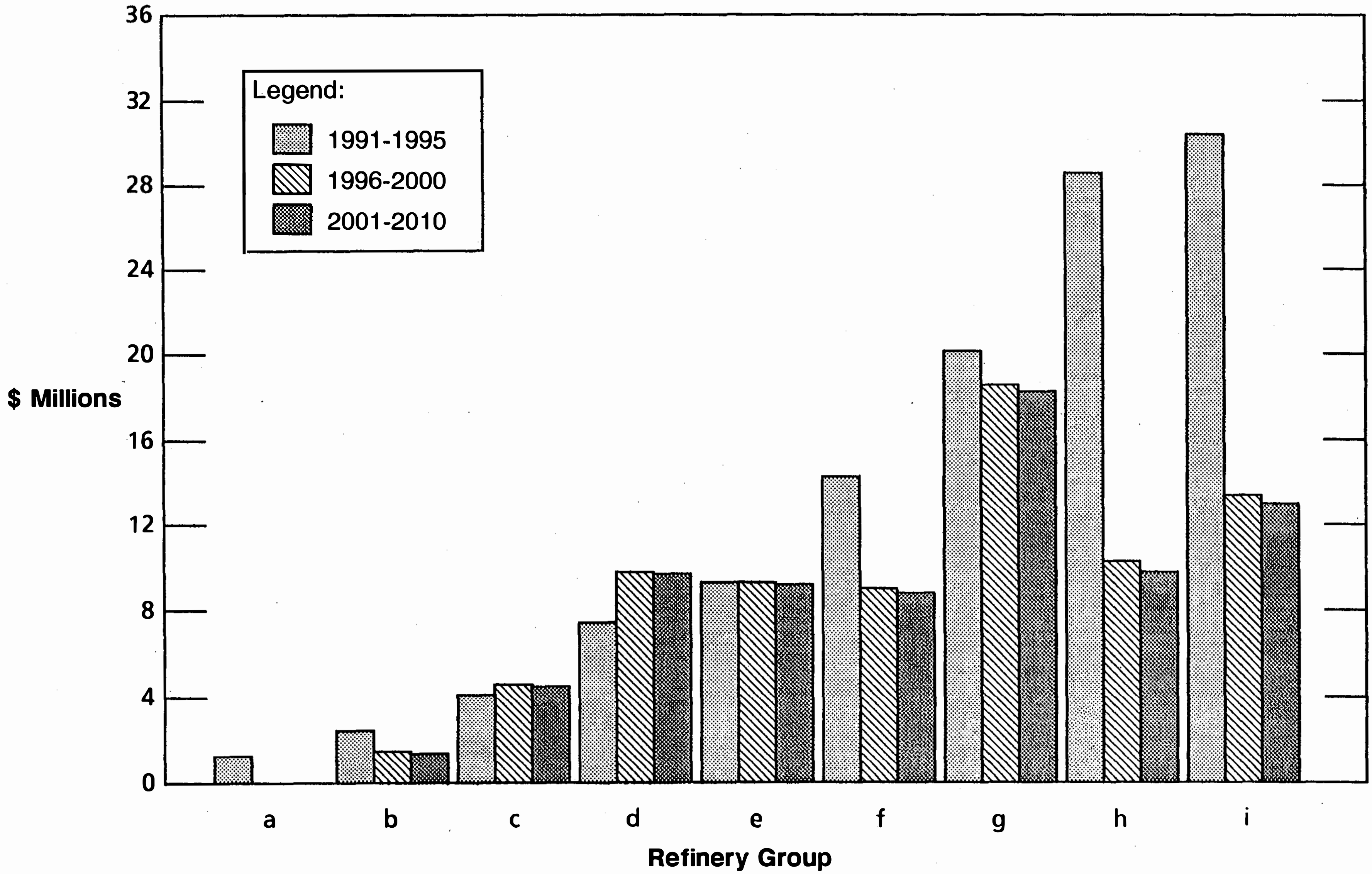
Table 6-3

CAPITAL INVESTMENT FOR SAFETY AND HEALTH CONTROL TECHNOLOGIES PER REFINERY PER GROUP ($ MILLION)

Group	No. of Refineries Per Group	Capital Investment Per Group	Capital Investment Per Refinery			
			1991-1995	1996-2000	2001-2010	Total
a	26	34	1	<1	<1	1
b	24	126	2	2	1	5
c	40	530	4	5	4	13
d	28	753	7	10	10	27
e	12	334	9	10	9	28
f	24	770	14	9	9	32
g	11	624	20	19	18	57
h	14	681	29	10	10	49
i	8	454	30	14	13	57
Total	187	4,306	--	--	--	--

Figure 6-1

CAPITAL INVESTMENT FOR PROCESS SAFETY AND HEALTH CONTROL TECHNOLOGIES PER REFINERY PER GROUP



1092001-2

Table 6-4

SAFETY AND HEALTH TECHNOLOGY COSTS
INCREMENTAL ONE-TIME COSTS
ALL REFINERY GROUPS
($ MILLION)

	Implementation Period			
	91-95	96-00	01-10	Total
Construction/Operating Permit	22	66	0	88
Process Control Safety Systems (ESDs)	51	0	0	51
Phase-out Hazardous Materials (HF)	0	81	81	162
Regulation of Ceramic Fiber and Calcium Silicate	50	0	0	50
Operator Training and Certification				
Initial Training	88	0	0	88
Update Training	0	0	0	0
Subtotal	88	0	0	88
Controlling Worker Exposure	159	0	0	159
Contractor Training	12	0	0	12
PSM				
PSM Program	335	0	0	335
PSM Related Training	11	0	0	11
Subtotal	345	0	0	345
Toxic Exposure	7	0	0	7
All Refinery Groups Incremental Capital Investment	734	147	81	963

Note: Columns and rows may not add due to rounding.

Table 6-5

ONE-TIME COSTS FOR SAFETY AND HEALTH CONTROL TECHNOLOGIES PER REFINERY PER GROUP ($ MILLION)

			One-Time Costs Per Refinery			
Group	No. of Refineries Per Group	One-time Costs Per Group	1991-1995	1996-2000	2001-2010	Total
a	26	18	<1	---	<1	<1
b	24	31	1	<1	<1	1
c	40	112	2	<1	<1	3
d	28	133	3	1	<1	5
e	12	69	4	1	<1	6
f	24	183	6	1	<1	8
g	11	118	8	2	1	11
h	14	181	11	1	<1	13
i	8	118	12	2	<1	15
Total	187	963	---	---	---	---

Table 6-6 presents the details on what process safety and health control devices and programs are covered by these O&M expenses.

The O&M expenses during the 1991 through 1995 time frame are for six programs. In the 1996 through 2000 and 2001 through 2010 periods, the O&M expense is the incremental O&M expenses of H_2SO_4 acid alkylation units over HF acid alkylation units.

Table 6-6

SAFETY AND HEALTH TECHNOLOGY COSTS
INCREMENTAL O&M COSTS
ALL REFINERY GROUPS
($ MILLION/YEAR)

	Implementation Period		
	1995	2000	2010
Construction/Operating Permit	0	0	0
Process Control Safety Systems (ESDs)	12	0	0
Phase-out Hazardous Materials (HF)	0	178	178
Regulation of Ceramic Fiber and Calcium silicate	0	0	0
Operator Training and Certification			
Initial Training	0	0	0
Update Training	9	0	0
Subtotal	9	0	0
Controlling Worker Exposure	11	0	0
Contractor Training	2	0	0
PSM			
PSM Program	0	0	0
PSM Related Training	24	0	0
Subtotal	24	0	0
Toxic Exposure	1	0	0
All Refinery Groups Incremental Capital Investment	58	178	178

Note: Columns and rows may not add due to rounding.

GLOSSARY

GLOSSARY

Air Quality Standard

A permissible level of a pollutant in the ambient air above which there is a potential impact on public health and welfare.

Air Toxics

Any air pollutant for which a National Ambient Air Quality Standard does not exist (i.e., excluding ozone, carbon monoxide, PM-10, sulfur dioxide, nitrogen dioxide) that may reasonably be anticipated to cause serious or irreversible chronic or acute health effects in humans or have adverse impacts on the surrounding flora and fauna.

Alkylation

A refining process for chemically combining isobutane with olefin hydrocarbons (e.g., propylene, butylene) through the control of temperature and pressure in the presence of an acid catalyst, usually sulfuric acid or hydrofluoric acid. The product alkylate, an isoparaffin has high octane value and is blended with motor and aviation gasoline to improve the antiknock value of the fuel.

Aromatics

Hydrocarbons characterized by unsaturated ring structures of carbon atoms. Commercial petroleum aromatics are benzene, toluene, and xylene (BTX).

Atmospheric Crude Oil Distillation

The refining process of separating crude oil components at atmospheric pressure by heating to temperatures of about 600 to 750° F (depending on the nature of the crude oil and desired products) and subsequent condensing of the fractions by cooling.

Attainment Area

An area considered to have air quality as good as or better than the National Ambient Air Quality Standards as defined in the Clean Air Act (e.g., ozone attainment, CO attainment). An area may be an attainment area for one pollutant and a nonattainment area for others. See also Nonattainment Area.

Barrel

A volumetric unit of measure for crude oil and petroleum products equivalent to 42 U.S. gallons. This measure is used in most statistical reports.

Barrels Per Calendar Day

The maximum number of barrels of input that can be processed during a 24-hour period after making allowances for the following limitations:

- The capabilities of downstream facilities to absorb the output of crude oil processing facilities of a given refinery. No reduction is made when a planned distribution of intermediate streams through other than downstream facilities is part of a refinery's normal operation
- The types and grades of inputs to be processed
- The types and grades of products expected to be manufactured
- The environmental constraints associated with refinery operations
- The reduction of capacity for scheduled downtime such as routine inspection, mechanical problems, maintenance, repairs, and turnaround
- The reduction of capacity for unscheduled downtime such as mechanical problems, repairs, and slowdowns

Barrels Per Stream Day

The amount a unit can process running at full capacity under optimal crude oil and product slate conditions.

Best Available Control Technology (BACT)

Technology that achieves a level of emission control determined on a case-by-case basis taking into account energy, environmental, and economic impacts.

Catalytic Cracking

The refining process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil. Catalytic cracking processes fresh feeds and recycled feeds.

Catalytic Hydrocracking

A refining process that uses hydrogen and catalysts with relatively low temperatures and high pressures for converting middle boiling or residual material to high-octane gasoline, reformer charge stock, jet fuel and/or high grade fuel oil. The process uses one or more catalysts, depending upon product output, and can handle high sulfur feedstocks without prior desulfurization.

Catalytic Hydrotreating

A refining process for treating petroleum fractions from atmospheric or vacuum distillation units (e.g., naphthas, middle distillates, reformer feeds, residual fuel oil, and heavy gas oil) and other petroleum (e.g., cat cracked naphtha, coker naphtha, gas oil, etc.) in the presence of catalysts and substantial quantities of hydrogen. Hydrotreating includes desulfurization removal of substances (e.g. nitrogen compounds) that deactivate catalysts, conversion of olefins to paraffins to reduce gum formation in gasoline, and other processes to upgrade the quality of the fractions.

Catalytic Reforming

A refining process using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules, thereby converting paraffinic and naphthenic type hydrocarbons (e.g., low-octane gasoline boiling range fractions) into petrochemical feedstocks and higher octane stocks suitable for blending into finished gasoline. Catalytic reforming is reported in two categories. They are:

- **Low Pressure** - A processing unit operating at less than 225 pounds per square inch gauge (PSIG) measured at the outlet separator.
- **High Pressure** - A processing unit operating at either equal to or greater than 225 pounds per square inch gauge (PSIG) measured at the outlet separator.

Charge Capacity

The input (feed) capacity of the refinery processing facilities.

Carbon Monoxide (CO)

Criteria Air Pollutants

A set of pollutants for which national ambient air quality standards have been established by the EPA. These pollutants are nitrous oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), Particulate matter less than 10 microns (PM-10), lead, and ozone. Volatile organic compounds (VOCs) are not criteria pollutants, but are regulated with NO_x because they are ozone precursors.

Crude Oil Qualities

Refers to two properties of crude oil, the sulfur content and API gravity, which affect processing complexity and product characteristics.

Delayed Coking

A process by which heavier crude oil fractions can be thermally decomposed under conditions of elevated temperatures and pressure to produce a mixture of lighter oils and petroleum coke. The light oils can be processed further in other refinery units to meet product specifications. The coke can be used either as a fuel or in other applications such as the manufacturing of steel or aluminum.

Distillate Fuel Oil

A general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, on-and-off-highway diesel engine fuel including railroad engine fuel and fuel for agricultural machinery, and electric power generation. Included are products known as No. 1, No. 2, and No 4 diesel fuels.

Energy Information Administration (EIA)

An independent statistical and analytical agency within the Department of Energy.

Environmental Protection Agency (EPA)

An independent federal agency in the executive branch that coordinates governmental action in regard to the environment.

Equipment Leaks

Organic emissions from fugitive sources per Section H of the Hazardous Organic regulations of the Natural Emission Standards for Hazardous Air Pollutants.

Ethyl Tertiary Butyl Ether (ETBE)

An oxygenate produced by the combination of ethanol with isobutylene.

Flexicoking

A thermal cracking process which converts heavy hydrocarbons such as crude oil, tar sands bitumen, and distillation residues into light hydrocarbons. Feedstocks can be any pumpable hydrocarbons including those containing high concentrations of sulfur and metals.

Fluid Coking

A thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

Fugitive Emissions

Emissions from non-discrete sources such as a pump, flange, seal, and valve leaks, equipment leaks, dust from conveyors and roadways, and emissions from other process points that could not reasonably pass through a stack, chimney, vent, or other functional equipment opening.

Gas Oil

A liquid petroleum distillate having a viscosity intermediate between that of kerosene and lubricating oil. It derives its name from having originally been used in the manufacture of illuminating gas. It is now used to produce distillate fuel oils and gasoline.

Gasoline Blending Components

Naphthas which will be used for blending or compounding into finished aviation or motor gasoline (e.g., straight-run gasoline, alkylate, and reformate). Excludes oxygenates (alcohols, ethers), butane, and pentanes plus.

Groundwater

Water below the surface in a zone of saturation.

Hazardous Air Pollutants (HAP)

Any air pollutant listed under 40CFR61 and 40CFR63 pursuant to Section 112 of the CAAA.

Hazardous Organic NESHAP (HON)

Hazardous organic air pollutants per the National Emission Standards for Hazardous Air Pollutants (40CFR63).

Hazard and Operability Study (HAZOP)

HAZOP is a formally structured method of systematically investigating each element of a system for all the ways in which important parameters can deviate from the intended design conditions to create hazards and operability problems.

Heavy Gas Oil

Petroleum distillates with an approximate boiling range from 650 to 1000° F.

Idle Capacity

The component of operable capacity that is not in operation and not under active repair, but capable of being placed in operation within 30 days; and capacity not in operation but under active repair that can be completed within 90 days.

Isomerization

A refining process which alters the fundamental arrangement of atoms in the molecule without adding or removing anything from the original material. Used to convert normal butane into isobutane ($i\text{-}C_4$), an alkylation process feedstock, and normal pentane and hexane into isopentane ($i\text{-}C_5$) and isohexane ($i\text{-}C_6$), high-octane gasoline components.

Kerosene

A petroleum distillate that has a maximum distillation temperature of 401° F at the 10-percent recovery point, a final boiling point of 572° F, and a minimum flash point of 100° F. Included are the two grades designated in ASTM D3699: No. 1-K and No. 2-K, and all grades of kerosene called range or stove oil. Kerosene is used in space heaters, cook stoves, and water heaters and is suitable for use as an illuminant when burned in wick lamps.

Kerosene-Type Jet Fuel

A quality kerosene product with a maximum distillation temperature of 400° F at the 10-percent recovery point and a final maximum boiling point of 572° F. The fuel is designated in ASTM Specification D1655 and Military Specification MIL-T-5624L (Grades JP-5 and JP-8). A relatively low-freezing point distillate of the kerosene type used primarily for commercial turbojet and turboprop aircraft engines.

Light Gas Oils

Liquid petroleum distillates heavier than naphtha, with an approximate boiling range from 400 to 650° F.

Liquified Petroleum Gases (LPG)

Ethane, ethylene, propane, propylene, normal butane, butylene, and isobutane produced at refineries or natural gas processing plants that fractionate raw natural gas plant liquids.

Liquified Refinery Gases (LRG)

Liquefied petroleum gases fractionated from refinery or still gases. Through compression and/or refrigeration, they are retained in the liquid state. The reported categories are ethane/ethylene, propane/propylene, normal butane butylene, and isobutane. Excludes still gas.

Lowest Achieve Emission Rate (LAER)

The most stringent emission rate achieved in practice by the same of similar source.

Material Safety Data Sheet (MSDS)

Material Safety Data Sheets are written or printed material concerning a hazardous chemical which is prepared in accordance with paragraph (g) of Process Safety Management Regulations, 29CFR 1910.1200.

Maximum Achievable Control Technology (MACT)

Technology that achieves a level of emission control set by the EPA per Section 112 of CAAA.

Middle Distillates

A general classification that includes distillate fuel oil and kerosene.

Methyl Tertiary Butyl Ether (MTBE)

An oxygenate used by refiners for gasoline blending. MTBE is produced by the combination of isobutylene and methanol.

Minimum Technology Requirements (MTR)

The design of RCRA land sites such as surface impoundments and landfills designating the minimum thickness or natural liners and leak rates.

Naphtha-Type Jet Fuel

A fuel in the heavy naphtha boiling range. ASTM Specification D1655 specifies for this fuel maximum distillation temperatures of 290° F at the 20-percent recovery point and 470° F at the 90-percent point, meeting Military Specification MIL-T-5624L (Grade JP-4). JP-4 is used for turbojet and turboprop aircraft engines, primarily by the military. Excludes ram-jet and petroleum base rocket fuels.

National Ambient Air Quality Standards (NAAQS)

Maximum allowable concentration of a pollutant in the atmosphere.

National Emission Statement for Hazardous Air Pollutants (NESHAP)

A set of technology based or work practice emission standards for prescribed hazardous air pollutants (carcinogens, mutagens, etc.) as defined in 40CFR61.

NESCAUM States

Northeast States for Coordinated Air Use Management. Includes New York, New Jersey, and all six New England states.

Nonattainment Area

Regional area that is not in compliance with criteria set forth in the Clean Air Act (e.g., ozone nonattainment, CO nonattainment). See also Attainment Area.

Nitrogen Oxides (NO_x)

Chemical compounds containing nitrogen and oxygen; reacts with volatile organic compounds in the presence of heat and sunlight to form ozone. It also contributes to acid rain.

Operable Capacity

The amount of capacity that, at the beginning of the period, is in operation; not in operation and not under active repair, but capable of being placed in operation within 30 days; or not in operation but under active repair that can be completed within 90 days. Operable capacity is the sum of the operating and idle capacity and is measured in barrels per calendar day or barrels per stream day.

Operable Utilization Rate

Represents the utilization of the atmospheric crude oil distillation units. The rate is calculated by dividing the gross input to these units by the operable refining capacity of the units.

Operating Capacity

The component of operable capacity that is in operation at the beginning of the period.

Oxygenates

Alcohols and ethers (e.g., ethanol, ethyl tertiary butyl ether; methanol, methyl tertiary butyl ether, tertiary amyl methyl ether, and tertiary butyl alcohol).

Ozone

A compound consisting of three oxygen atoms, which is a significant constituent of smog. It is formed through chemical reactions in the atmosphere involving volatile organic compounds, nitrogen oxides, and sunlight.

Petroleum Administration for Defense (PAD) Districts

Geographic aggregations of the 50 States and the District of Columbia into five districts by the Petroleum Administration for Defense in 1950. These districts were originally instituted for economic and geographic reasons as Petroleum Administration for War (PAW) Districts, which was established in 1942.

Petroleum Coke

A residue, the final product of the condensation process in cracking. This product is reported as marketable coke or catalyst coke.

Particulate Matter (PM-10)

A new standard for measuring the amount of solid or liquid matter, under 10 microns in diameter, suspended in the atmosphere.

Point Source

A stationary location or fixed facility from which pollutants are discharged or emitted.

Process Hazardous Analysis (PHA)

A process hazard analysis is an organized and systematic effort to identify and analyze the significance of potential hazards associated with the processing or handling of highly hazardous chemicals.

Process Safety Management

Process safety management is the proactive identification, evaluation, and mitigation or prevention of chemical releases that could occur as a result of failures in processes, procedures, or equipment.

Process Vent

Any open-ended pipe or stack that is vented to the atmosphere either directly, through a vacuum-producing system, or from a tank.

Propylene (C_3H_6)

An olefinic hydrocarbon recovered from refinery processes or petrochemical processes.

Reasonably Achievable Control Technology (RACT)

Technology set forth in the CAAA that achieves the lowest emission limit applicable to a given source using reasonably available and economically feasible control equipment.

Refinery Gas

Any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes. The principal constituents are methane, ethane, ethylene, normal butane, butylene, propane, propylene, etc. Still gas is used as a refinery fuel and a petrochemical feedstock.

Refinery Input, Total

The raw materials and intermediate materials processed at refineries to produce finished petroleum products. They include crude oil, products of natural gas processing plants, unfinished oils, other hydrocarbon and alcohol, motor gasoline and aviation gasoline blending components and finished petroleum products.

Residual Fuel Oil

The heavier oils that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations and that conform to ASTM Specifications D396 and 975. Included are No. 5, a residual fuel oil of medium viscosity; Navy Special, for use in steam-powered vessels in government service and in shore power plants; No. 6, which includes Bunker C fuel oil, and it used for commercial and industrial heating, electricity generation and to power ships. Imports of residual fuel oil include imported crude oil burned as fuel.

Residuum

Residue from crude oil after distilling off all but the heaviest components, with a boiling range greater than 1000° F.

Risk Assessment

Process risks are normally evaluated by considering hazardous event probability (likelihood) and consequence (severity).

Shell Storage Capacity

The design capacity of a petroleum storage tank which is always greater than or equal to working storage capacity.

State Implementation Plan (SIP)

Documents prepared by states, and submitted to EPA for approval, that identify actions and programs to be undertaken by the state and its subdivisions to implement their responsibilities under the Clean Air Act.

Solid Waste Management Unit (SWMU)

A facility such as a landfill, surface impoundment, waste pile, or land farm used to store, treat, or dispose of solid waste material.

Surface Impoundment

A natural or man-made depression primarily of earthen materials designed to hold an accumulation of liquids.

Tertiary Amyl Methyl Ether (TAME)

An oxygenate for gasoline blending, produced by the combination of isopentene (isoamylene) and methanol.

Tank Farm

An installation used by gathering and trunk pipeline companies, crude oil producers, and terminal operators (except refineries) to store crude oil.

Toxic Air Pollutants (TAP)

As described in the Clean Air Act. See Air Toxics.

Thermal Cracking

A refining process in which heat and pressure are used to break down, rearrange, or combine hydrocarbon molecules. Thermal cracking includes gas, oil, visbreaking, fluid coking, delayed coking, and other thermal cracking processes (e.g., flexicoking). See individual categories or definition.

Toxics

See Air Toxics.

Visbreaking

A thermal cracking process in which heavy atmospheric or vacuum-still bottoms are cracked at moderate temperatures to increase production of distillate products and reduce viscosity of the distillation residues.

Volatile Organic Compounds (VOC)

Does not include methane and other compounds determined by EPA to have negligible photochemical reactivity.

Working Storage Capacity

The difference in volume between the maximum safe fill capacity and the quantity below which pump suction is ineffective (bottoms).

ABBREVIATIONS

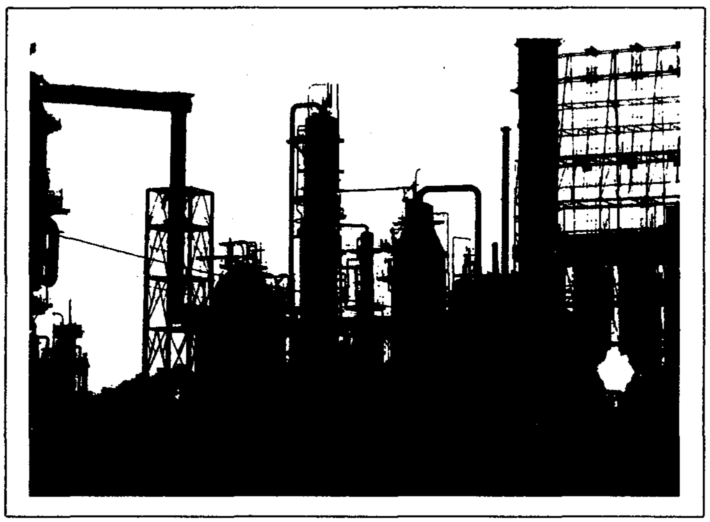
ABBREVIATIONS

API	-	American Petroleum Institute
ASP	-	Activated-Sludge Plant
BACT	-	Best Available Control Technology
BPCD	-	Barrels Per Calendar Day
BPSD	-	Barrels Per Stream Day
CAAA	-	Clean Air Act Amendments of 1990
CERCLA	-	Comprehensive Environmental Response, Compensation, and Liability Act
CSB	-	Chemical Safety and Hazard Investigation Board
CWA	-	Clean Water Act
DOE	-	Department of Energy
EHS	-	Extremely Hazardous Substances
EPA	-	Environmental Protection Agency
FGR	-	Flue Gas Recirculation
FIP	-	Federal Implementation Plan
GACT	-	Generally Available Control Technology
HA	-	Hazard Assessment
HAP	-	Hazardous Air Pollutant
HAZOP	-	Hazard and Operability
HHC	-	Highly Hazardous Chemical
HON	-	Hazardous Organic NESHAP
LAER	-	Lowest Achievable Emission Rate
LEPC	-	Local Emergency Planning Commission
MACT	-	Maximum Achievable Control Technology
MEI	-	Maximum Exposed Individual
MSDS	-	Material Safety Data Sheets
MTR	-	Minimum Technology Requirements
NAAQS	-	National Ambient Air Quality Standards
NEDS	-	National Emissions Data System
NESHAP	-	National Emissions Standards for Hazardous Air Pollutants
NPDES	-	National Pollutant Discharge Elimination System
NTSB	-	National Transportation Safety Board
OSHA	-	Occupational Safety and Health Administration
PACT	-	Powdered Activated Carbon Treatment
PADD	-	Petroleum Administration for Defense Districts
PHA	-	Process Hazards Analysis
PSM	-	Process Safety Management
RACT	-	Reasonable Achievable Control Technology
RCRA	-	Resource Conservation and Recovery Act of 1976
RMP	-	Risk Management Plan
SIP	-	State Implementation Plan
SOCMI	-	Synthetic Organic Chemical Manufacturing Industry
SRU	-	Sulfur Recovery Unit
SWMU	-	Solid Waste Management Unit
TSCA	-	Toxic Substances Control Act
TSS	-	Total Suspended Solid
VOC	-	Volatile Organic Compound

SECTION III

EXECUTIVE SUMMARY OF AMOCO/EPA POLLUTION PREVENTION PROJECT

Amoco – U.S. EPA
Pollution Prevention Project
Yorktown, Virginia



Executive Summary

Printed on recycled paper

AMOCO/USEPA POLLUTION PREVENTION PROJECT

Executive Summary

December, 1991
(Revised, May, 1992)

AMOCO/EPA Pollution Prevention Project
Executive Summary

Table of Contents

Foreword

This volume provides an executive summary of work completed during a voluntary, AMOCO/USEPA Pollution Prevention Project undertaken at Amoco Oil Company's Yorktown, Virginia Refinery. Overall goals of the Project were to (1) inventory releases of all pollutants to the environment from the Refinery; (2) develop, evaluate and rank process, maintenance and operating options that reduce these releases; and (3) identify barriers and incentives to implementing the alternatives identified.

Special thanks are due to the AMOCO/USEPA Workgroup who provided Project oversight and direction during this two-year, $2.3 million effort. In addition, more than 200 people, from 35 organizations participated at various times in this unique Project. Their enthusiasm and contributions are obvious from the wealth of ideas developed, considered and analyzed. Their assistance supports a central belief of this Project: that developing effective solutions to complex environmental management problems will take the best efforts of the many 'partners' in our society. We extend a personal thanks to all participants.

Howard Klee, Jr. Amoco Corporation	Mahesh Podar USEPA

Amoco/USEPA Pollution Prevention Project

ABSTRACT

In late 1989, Amoco Corporation and the United States Environmental Protection Agency began a voluntary, joint project to study pollution prevention opportunities at an industrial facility. The Amoco/EPA Workgroup, composed of EPA, Amoco and Commonwealth of Virginia staff, agreed to use Amoco Oil Company's refinery at Yorktown, Virginia, to conduct a multi-media assessment of releases to the environment, then to develop and evaluate options to reduce these releases. The Workgroup identified five tasks for this study:

1. Inventory refinery releases to the environment to define their chemical type, quantity, source, and medium of release.

2. Develop options to reduce selected releases identified.

3. Rank and prioritize the options based on a variety of criteria and perspectives.

4. Identify and evaluate factors such as technical, legislative, regulatory, institutional, permitting, and economic, that impede or encourage pollution prevention.

5. Enhance participants' knowledge of refinery and regulatory systems.

Project Organization, Staffing, and Budget

Workgroup: Monthly Workgroup meetings provided Project oversight, a forum for presentations on different Project components, and an opportunity for informal discussion of differing viewpoints about environmental management. Although attendance varied, each meeting included representatives from various EPA offices, the Commonwealth of Virginia, and Amoco.

Peer Review: At the Workgroup's request, EPA arranged for Resources for the Future to assemble a group of outside scientific and technical experts. This Peer Review Group provided evaluation and advice on the Project workplan, sampling, analysis results, and conclusions. Members of this group were paid a small honoraria for their participation.

Workshop: A special Workshop, held during March 24-27, 1991 in Williamsburg, Virginia, reviewed sampling data and identified reduction options and ranking criteria. More than 120 people from diverse backgrounds--EPA, Amoco, Virginia, academia and public interest groups--attended the Workshop.

Participants: More than 200 people, 35 organizations, and many disciplines were involved in this Project. This reflected a central belief of this Project that solving difficult environmental problems must draw on many of society's "partners."

Cost: Total cost for this Project was approximately $2.3 million. Amoco Oil Company provided 70 percent of the funding and EPA the remainder.

Lessons and Results

Refinery Release Inventory

A. Existing estimates of environmental releases were not adequate for making a chemical-specific, multi-media, facility-wide assessment of the Refinery.

B. A substantial portion of pollution generated at this refinery is not released to the environment.

C. The Toxic Release Inventory database does not adequately characterize releases from this Refinery.

D. Site specific features, determined during the facility-wide assessment, affect releases and release management options.

Reducing Releases

A. A workshop approach, drawing on a diverse group representing government, industry, academic, environmental, and public interests, developed a wide range of release reduction options in a multi-media context more quickly than either EPA or industry alone would do.

B. Pollutant release management frequently involves the transfer or conversion of pollutants from one form or medium to another.

C. Although the Refinery is highly efficient in handling materials (currently recovering 99.7 percent of its feedstock in products and fuel), four source reduction options identified show positive rates of return ranging from one to nineteen percent.

D. Source reduction is not necessarily practical for all release management options, despite its cost effectiveness. Effective release management requires a combination of source reduction, recycling; treatment and safe disposal.

Choosing Alternatives

A. Ranking the options showed that better environmental results can be obtained more cost-effectively. At this facility, about 97 percent of the release reductions that regulatory and statutory programs require can be achieved for about 25 percent of today's cost for these programs. Table 1.3 summarizes several management options.

These savings could be achieved if a facility-wide release reduction target existed, if statutes and regulations did not prescribe the methods to use, and if facility operators could determine the best approach to reach that target.

B. All participants agreed on which options were the most effective and which were least, regardless of their institutional viewpoints and preferred ranking criteria.

Obstacles and Incentives to Implementing Pollution Prevention

A. EPA does not have the policy goal and may not have the statutory authority to simply set an emissions reduction "target" without prescribing how this target should or could be met. Current administrative procedures discourage such an approach, including the analysis of tradeoffs in risks, benefits, and costs of managing residual pollutants in different media.

The Agency is required to implement media-specific legislation enacted by Congress. In addition, EPA does not have the technical and analytical skills to determine if multi-media, facility-wide reduction plans are meeting the requirements established in single medium-specific legislation. This would make compliance monitoring and enforcement more difficult than present approaches.

B. Many legislative and regulatory programs do not provide implementation schedules compatible with design, engineering, and construction timeframes. Consequently, short-term "fixes" which meet legal deadlines are used at the expense of more cost- and environmentally effective, long-term, solutions.

C. Well established problem-solving approaches are difficult to change. Congress, EPA, and much of industry are used to command-and-control, end-of-pipe treatment approaches based on twenty years of experience. Many of today's problems could benefit from a different approach.

D. Inadequate accounting for both the benefits and costs of environmental legislation and regulations is an obstacle to developing a more efficient environmental management system.

Responsibility for pollutant generation and accountability for environmental protection are difficult to quantify.

Recommendations

1. **Explore Opportunities to Produce Better Environmental Results More Cost-effectively.**

2. **Improve Environmental Release Data Collection, Analysis and Management.**

3. **Provide Incentives for Conducting Facility-wide Assessments, and Developing multi-media Release Reduction Strategies. Such Strategies must Consider the Multi-Media Consequences of Environmental Management Decisions.**

4. **Encourage Additional Public/Private Partnerships on Environmental Management.**

5. **Conduct Research on the Potential Health and Ecological Effects of VOCs.**

SUMMARY

1.1 Project Goals

In late 1989, Amoco Corporation (Amoco) and the United States Environmental Protection Agency (EPA) began a voluntary, joint project to study pollution prevention opportunities at an industrial facility. The Amoco/EPA workgroup (Workgroup), composed of EPA, Amoco, and Commonwealth of Virginia staff, agreed to use Amoco Oil Company's refinery at Yorktown, Virginia (the Refinery), to conduct a multi-media assessment of releases to the environment, then to develop and evaluate options to reduce these releases. The Workgroup identified five tasks for this study:

1. Inventory refinery releases to the environment to define their chemical type, quantity, source, and medium of release.

2. Develop options to reduce selected releases identified.

3. Rank and prioritize the options using a variety of criteria and perspectives.

4. Identify and evaluate factors such as technical, legislative, regulatory, institutional, permitting, and economic, that impede or invite pollution prevention.

5. Enhance participants' knowledge of refinery and regulatory systems.

Figure 3.1 shows a schematic diagram of the Refinery, potential release sources, and a number of pollution prevention options identified in this Project. Table 3.2 describes specific options to reduce releases. At the time this Project began, pollution prevention was a concept predicated on reducing or eliminating releases of materials into the environment rather than managing the releases later. The Workgroup adopted this general concept and agreed to consider all opportunities--source reduction, recycling, treatment, and environmentally sound disposal--as potential choices in pollution management. Since then, Congress, in the Pollution Prevention Act of 1990, and other organizations, have put greater emphasis on source reduction as the primary, if not the exclusive, means to accomplish pollution prevention.

A central goal of this Project was to identify criteria and develop a ranking system for prioritizing environmental management opportunities that recognized a variety of factors including release reduction, technical feasibility, cost, environmental impact, human health risk, and risk reduction potential. Due to the inherent uncertainties in risk assessments, the Project focused on <u>relative</u> changes in risk compared to current levels, rather than establishing absolute risk levels. Because of difficulties in quantifying changes in ecological impact from airborne emissions, changes in relative risk were based primarily on human health effects indicated by changes in exposure to benzene. The risk assessment did not include a quantitative analysis of VOCs due to limited information on their health effects.

This project focused on pollution and potential risks posed by normal operation of the Refinery and chronic exposure to its releases into the environment. Minimizing emergency and upset events is a top priority of Amoco's facility managers. Such events can have catastrophic results. However, they were not studied in this project because: (a) prevention and control of such events involves significantly different skills, technical resources, and analyses than controlling releases from day-to-day operations (AIChE, 1985); (b) the number, type, and frequency of incidents at Yorktown is very low; and (c) data regarding the type of release, and relevant meteorology during the release are not available for analysis. Appendix D describes potential emergency and upset events that might occur at a petroleum refinery and the general preventative measures used to minimize their severity and the likelihood of their occurrence.

1.2 Project Organization, Staffing and Budget

Project Content: The Pollution Prevention Project has many components. Each component defines and addresses an issue associated with pollution prevention and facility management choices. These include pollutant source identification, sampling, exposure modeling, risk assessment, etc. Table 1.1 provides a complete list of the components in this Project. The Project workplan outlined the purpose and content for most of these components (Amoco/EPA, 1990).

Exclusions/Limitations: A number of areas specifically excluded or limited in this Project are described in Appendix B. Some are listed below:

- Limited sampling time and data provided a "snapshot" of releases rather than measured annual values.
- Very few generally accepted methodologies exist for the sampling used to obtain a site-wide release inventory, particularly for measuring air emissions. Both EPA and Amoco concerns about specific sampling issues are highlighted in Appendix B and discussed in more detail in Air Quality Data, Volume II (Amoco/EPA, 1992 b).
- The Project considered available technologies rather than exploring innovative techniques for reducing releases.

- Chemical changes of airborne pollutants were not evaluated.

- Data and analysis focused on the Yorktown Refinery. Site-specific features of this facility and its emissions may not apply to other refineries. Broader regional concerns were not evaluated.

- The forthcoming human health risk assessment focuses on potential cancer risks associated with benzene exposure outside the facility fenceline.

Peer Review: At the Workgroup's request, Resources for the Future organized a group of outside scientific and technical experts. This Peer Review Group provided evaluation and advice on the Project workplan, sampling, analytical results, and conclusions. Members of this group were paid a small honoraria for their participation and reimbursed for travel expenses to Washington by EPA. A report summarizing their comments is included as part of the documentation for this Project. Appendix C lists all Project documentation.

Workgroup: Monthly Workgroup meetings provided Project oversight, a forum for presentations on different Project components, and an opportunity for informal discussion of differing viewpoints about environmental management. Although attendance varied, each meeting included representatives from various EPA offices, the Commonwealth of Virginia, and Amoco.

Workshop: A special Workshop, held during March 24-27, 1991, in Williamsburg, Virginia, reviewed sampling data and identified reduction options and ranking criteria. More than 120 people from diverse backgrounds--EPA, Amoco, Virginia, academia and public interest groups--attended the Workshop. The Workshop sessions resulted in suggestions that further refined and directed Project activities (Amoco/EPA, 1991a).

Participants: More than 200 people, 35 organizations, and many disciplines have been involved in this Project. Table 1.2 lists the various participating organizations.

Cost: Total cost for this Project was approximately $2.3 million. Amoco Oil Company provided 70 percent of the funding and EPA the remainder.

1.3 Lessons and Results

1.3.1 Refinery Release Inventory

A. Existing estimates of environmental releases were not adequate for making a chemical-specific, multi-media, facility-wide assessment.

The Yorktown Refinery had good information about the quantity of material released to the York River from NPDES Permit monitoring requirements, and for solid wastes as a result of internal programs and participation in recent American Petroleum Institute surveys (API, 1991b). These releases, however, made up only 11 percent of the total releases from the facility. Available data did not include adequate chemical-specific characterization of the water discharge or solid waste streams.

The Refinery (and other refineries as well) could not easily identify specific airborne hydrocarbon compounds released or the quantity released because:

(a) Refineries typically do not manufacture products with specific chemical compositions, and therefore do not routinely measure chemical compositions of their products or emissions. Rather, refinery products have specific properties such as octane, freeze point, and sulfur content. Crude oil, the raw material used to make these products, contains thousands of distinct chemicals that are never fully separated during the manufacturing processes. Airborne releases from this kind of facility are similarly complex.

(b) Most hydrocarbons are released through a large number of widely distributed sources (valves, flanges, pump seals and tank vents). Even a small refinery may have more than 10,000 potentially different sources. Direct measurement of each of these sources is not practical.

(c) The quantities released through any single source are extremely small--on the order of pounds per year--dilute and difficult to measure. In addition, some large sources that emit pollutants in the amount of tons per year are difficult to measure and quantify. Total hydrocarbons released from Yorktown Refinery from <u>all</u> sources were approximately 0.3 weight percent of the total crude oil processed. Therefore, they would not be detected through normal mass balances and materials accounting (NRC, 1990).

Thus, collecting detailed, chemical specific release information used to characterize the Refinery was expensive and time consuming. This Project developed a sampling and monitoring program that included about 1,000 samples (see Figure 2.2). Each sample was analyzed for 15-20 chemicals. The sampling program took about 12 months to complete at a cost of about $1 million. Even with this time and dollar commitment, only selected sources were sampled. The final release inventory was assembled using a combination of sampling, measurements, dispersion modeling, and estimates based on emission factors.

Because this sampling program was a first of its kind effort, its scope was intentionally broad. Subsequent analysis showed that not all of the information obtained was necessary to identify significant sources and potential reduction options. For the Yorktown Refinery (and the petroleum refining industry overall), more general information, such as source specific VOC emissions, is adequate to identify many of the pollution prevention projects developed in this study. Total VOC emissions are a good indicator of overall emissions and can be used for tracking emissions reduction progress.

B. A substantial portion of pollution generated at this refinery is not released to the environment.

The release inventory process allowed a comparison of pollutant generation, on-site management and ultimate releases to the environment. The Refinery generates about 27,500 tons/year of pollutants. As a result of site hydrogeology, on-site wastewater treatment, and solid waste recycling practices, about 12,000 tons are recovered, treated or recycled and do not leave the Refinery site. Of the remaining 15,500 tons about 90 percent are released to the air.

Figure 2.4 illustrates the transfers which take place between generation and ultimate release. Figure 2.5 characterizes pollutants released from the Refinery. This site-wide analysis of pollutant generation and release characteristics allowed the Workgroup to focus much of the remaining Project resources on the largest releases--airborne emissions.

Modeling studies indicated relatively little naturally occurring transfer of hydrocarbon emissions from air into other media (Cohen and Allen, 1991). Most hydrocarbons are not very water soluble, and so are not easily removed from the air by rainfall. Section 2.0 includes a more detailed discussion of the potential for transfer to other media. Although the fate of criteria airborne pollutants (like NOX and SO2) was not studied in this Project, they are known to be scavenged by rainfall and can contribute to nitrogen loads and pH changes in lakes and soil (See Appendix B). Measurements and modeling results showed small transfers from some surface water ponds to groundwater. Groundwater also enters the wastewater treatment system through the underground sewers, resulting in a net groundwater inflow.

Transfers of pollutants between media do occur, particularly as a result of pollution management activities. Over 370 tons/year of hydrocarbons initially present in wastewater streams are volatilized into air from the water collection system. More than

2,000 tons/year of biosolids are produced by treating wastewater in the Refinery's activated sludge system.

C. The TRI database does not adequately characterize releases from this Refinery.

Title III of SARA, Emergency Planning and Community Right-to-Know Act, created the Toxic Release Inventory (TRI) in 1986. Title III requires regulated facilities in SIC Code 20-39 to submit annual release data on more than 300 chemicals manufactured, produced or otherwise used in quantities exceeding certain threshold values. Releases to all media must be reported. The TRI is one way of focusing corporate attention on release reduction opportunities.

TRI reports are based on either emission estimates, direct measurements or a combination of both methods. Each facility is responsible for the accuracy of the data reported. Industrial facilities frequently file amendments to TRI reports to reflect improvements in the accuracy of the estimation and measurement techniques.

The TRI database has become the de facto national release inventory. The quality and utility of data reported can vary widely. At a plant that uses a single solvent to wash manufactured parts, and that purchases extra solvent every year to make up for evaporative losses, the quantity of solvent emissions is well known and tracked through monthly purchasing records. A TRI report which included this solvent and plant should be quite accurate. However, at the Refinery, the TRI does not report total facility emissions because:

- The TRI is based on estimates rather than measurements. Estimating accuracy varies widely. During the measurement portion of this Project, several new sources were identified whose significance had been previously underestimated. One source was identified which had been overestimated. Figure 2.7 summarizes the results of this analysis.

- The measurement phase of this Project revealed substantially higher TRI reportable emissions from the blowdown stacks than had been estimated previously. On the other hand, measurements revealed that emissions from wastewater sources had been overestimated. Amoco has filed an amendment to its past TRI reports for Yorktown to reflect new data. Figure 2.7 compares the starting TRI data with results obtained from the Project.

- The TRI focuses on specific chemicals which account for only a portion of the total emissions. In the Refinery's case, the TRI report covers only 9 percent of the total hydrocarbons released, and only 2.4 percent of the total releases to all media. Criteria pollutants--CO, NOX, SO2, and PM-10--are not reportable in the TRI.

- Some activities and emissions are excluded by EPA from record keeping requirements, such as emissions from barge loading. At this facility, barge loading operations account for about 20 percent of the total benzene emissions (See Figure 3.4).

Finally, TRI provides an approximate inventory of selected materials released to the environment. TRI data by itself does not allow for meaningful risk evaluation or comparisons on a facility basis, because it does not define the facility's relationship to nearby populations and ecosystems.

D. Site specific features determined during the facility-wide assessment, affect releases and release management options.

National programs, by design, address overall problems in specific media. But these programs seldom consider site-specific differences in developing standards. Other refineries, and indeed other industrial facilities, can use the general sampling approach developed here to obtain the facility-wide release inventory. However, each site will exhibit unique geophysical and process characteristics. Each assessment plan must include these site-specific characteristics in its design and focus. As an example, the Yorktown Refinery does not have a hydrofluoric acid (HF) alkylation unit and HF was not measured. HF can pose a significant health risk if managed improperly, and may need to be tracked at facilities that use it.

Groundwater: As a result of a clay soil layer, unique hydrogeology, the placement of the underground drainage system relative to the water table, and local climate, groundwater movement at this site is minimal. In fact, the underground drainage system is acting as a groundwater collection unit, sending groundwater to the Refinery's wastewater treatment plant. Thus, groundwater at this site is not leaving the property. Furthermore, sampling showed surprisingly low levels of groundwater contamination, compared to other refineries (LA Times, 1988).

Marine Loading Emissions: Yorktown Refinery uses marine transportation for receiving all crude oil and shipping more than 80 percent of its products. Estimated releases from product loading operations are 784 tons/year of VOCs. Computer modeling analysis showed this source had the greatest impact on exposure of nearby residences to Refinery hydrocarbon emissions. Therefore, it would be useful to include marine loading emissions in this facility's environmental management plans. Many other refineries rely more on pipeline, rail and truck shipments to handle crude and products, and would thus not expect to find the same potential impact from marine operations.

Airshed Status: As discussed in Appendix A, the Refinery is located in an airshed classified as an attainment area for all criteria pollutants including ozone. Therefore, relatively few hydrocarbon emission controls have been required or installed at this facility. The sampling program and release reduction options focused on hydrocarbon releases. Many other refineries in ozone non-attainment areas have already installed extensive hydrocarbon emission controls. Consequently, other facilities may have a significantly lower percentage of hydrocarbon emissions. Similarly, NOX, CO, PM-10 and SO2 emissions have been more tightly controlled in some other airsheds (such as the Los Angeles basin) which do not meet NAAQS for these pollutants.

1.3.2 Release Reduction Options

A. A workshop approach, drawing on a diverse group representing government, industry, academic, environmental and public interests developed a wide range of release reduction options in a multi-media context more quickly than EPA or industry alone would do.

The release inventory described in 1.3.1 above, served as the basis for identifying ways to reduce releases. A 3-day brainstorming Workshop, held in Williamsburg, Virginia generated more than 50 potential release reduction options for the Refinery. These ranged from producing a single grade of gasoline to specific technical options for particular equipment or processes. Table 3.1 lists all options identified.

The Workgroup subsequently narrowed this list to 12 options for more careful, quantitative analysis. This winnowing process considered only those options that were technically feasible now, offered potentially large release reductions, addressed different environmental media, and posed no process or worker safety problems. Projects designed to comply with several current or anticipated regulations were also included. Table 3.2 lists engineering projects included for further analysis.

The Workshop also addressed screening criteria to help prioritize the options, potential barriers and incentives for implementation, and permitting concerns. The diverse viewpoints brought to all these discussions helped guide subsequent Project activities. These views reinforced the Workgroup's desire to consider broader issues such as multi-media release management consequences, future liability impacts, etc. The Workshop was able to consider these issues more comprehensively than either government or industry alone would normally do.

B. Release management frequently involves the transfer or conversion of pollutants from one form or medium to another.

It is not at all unusual for pollutants to be converted and transferred from one form or media to another as part of a pollution control practice. For example, scrubbers used to remove acidic pollutants from many electric utility stacks generate large volumes of calcium sulfate sludge (EPRI, 1983) which must also be managed. For options developed at the Yorktown Refinery:

- Modifications of the underground drainage system and process water treatment plant (required under the Benzene Waste Operations NESHAP; Federal Register, 1990) will improve process water treatment and reduce air emissions, but produce more solid waste such as biosolids and fully spent activated carbon.
- The Refinery has limited sludge processing capacity. Keeping soils out of sewers would reduce the amount of sludge in the API Separator and thus allow for more on-site management of other solid wastes, reducing offsite disposal.
- Installing an electrostatic precipitator would reduce FCU particulate (PM-10) emissions (catalyst fines), but transfer the additional collected particulates to land disposal.
- Burning hydrocarbons that cannot be economically recovered generates other criteria pollutants which may also need to be managed.

None of these transfers or transformations are bad, in and of themselves. The Project simply pointed out the need to recognize, plan, and manage these changes at an early stage of the release management cycle.

C. Source reduction options were more cost-effective than most treatment and disposal alternatives. Nevertheless, source reduction alone was not adequate to achieve all the desired or legally required release reductions.

The Workgroup agreed to consider the waste management hierarchy--source reduction, recycling, treatment, and safe disposal--as the basis for developing release reduction options. Technologies identified and analyzed fit into this hierarchy. Time and budget constraints limited technology choices to conventional, proven solutions rather than exploring innovative alternatives.

However, less than half the options identified qualified as "source reduction." Had the options been limited to only source reduction, the scope of potential opportunities for reducing releases and improving environmental quality would have been unnecessarily restricted.

If all source reduction options identified in this Project were implemented, benzene and total hydrocarbon emissions would be reduced by about 25 percent and 16 percent, respectively. The Workgroup concluded that a cost-effective strategy for the Refinery would have to include a mix of source reduction, recycling, treatment and disposal options.

Of the source reduction options considered, most appear to be significantly lower cost than recycling, treatment, and disposal. Source reduction options considered have had an average cost of $650/ton of pollutant recovered. The remaining seven options analyzed had an average cost of $3,200/ton, nearly 5 times higher. The cost-effectiveness of individual options varied form a low of $190/ton for secondary seals on gasoline storage tanks to a high of $128,000/ton for the treatment plant upgrade.

D. While release reductions do not always pay for themselves, some environmental improvements can be made at a net cost savings to the Refinery.

The Refinery is relatively efficient in managing materials. An ongoing weight-loss management program to capture lost material has been in place at all Amoco refineries for a number of years. Approximately 99.7 percent of the incoming crude is converted to useful products and refinery fuel. The hydrocarbon release reduction options identified in this Project dealt with the remaining 0.3 percent.

Despite the relative efficiency of the Refinery, two source reduction options--seals on gasoline tanks and a leak detection and repair program--have net cost savings and a positive rate of return. Amoco did not know this before this Project. On the other hand, some of the source reduction options and all treatment options were not economic investments for the Refinery. For example, fitting all fixed roof storage tanks with secondary seals would result in much higher cost for relatively little additional reduction in hydrocarbon emissions compared to fitting only gasoline storage tanks. Treatment options generally require significant capital outlays with no return in the form of recaptured or improved product. Technology options with positive rates of return are shown in Figure 3.9. Options that have negative return are not shown.

1.3.3 Choosing Alternatives

A. Ranking the options showed that better environmental results can be obtained more cost-effectively.

Compliance with current and anticipated regulations requires controls for eight sources types, reducing airborne hydrocarbon releases by 7,300 tons/year at an average cost of $2,400/ton. The Refinery could reduce about 7,100 tons of airborne hydrocarbons each year (or about 97 percent) by controlling six sources at about 25 percent of the cost. This cost-effectiveness comparison does not account for possible benefits to other media.

If allowed to address both hydrocarbons and listed hazardous waste, the Refinery could reduce about 7,500 tons per year at an average cost of about $500/ton using its choice of sources and techniques. Table 1.3 provides a more detailed comparison of different Release Management Strategies, results and costs.

These results are all the more significant because the options evaluated were neither selected nor developed ahead of time with a target reduction goal in mind. Nor did the selection process have a goal of meeting regulatory requirements in some alternative fashion. This suggests that even more impressive results might be achieved, if that were the focal point at the beginning.

B. All participants agreed on which options were the most effective and which were least, regardless of their ranking criteria or institutional viewpoints.

The Project used a multi-dimensional prioritizing process (the Analytical Hierarchy Process, AHP) in which weights were developed for all criteria used to rank alternatives. These criteria included cost, release reduction, timeliness and changes in benzene exposure, among others. The process allowed the Workgroup to assess the significance of and interactions between criteria--how changes in one criterion affect other criteria and total rankings.

All options were considered legally acceptable, and no specific regulatory requirements were imposed on the decision making process. Although different organizations brought different perspectives to the discussions, each organization reached the same conclusions about which options would be most effective and which were least. The driving forces in this prioritization were cost and relative risk reduction, as measured by benzene exposure. A variety of sensitivity studies confirmed this initial set of preferences.

Amoco ranked control of marine loading losses as the most effective--though not the lowest cost--option. A second tier of options included installing secondary seals on tanks, instituting a leak detection and repair program, and upgrading blowdown stacks. All four were also viewed as reasonably effective pollution prevention projects. In total these four projects would prevent or capture almost 6,900 tons of releases annually at a cost of about $510/ton. EPA and Virginia selected the same five options, in this hypothetical case with no specific regulatory requirements. See Items 4 and 5 in Table 1.3.

1.3.4 Obstacles and Incentives to Implementing Pollution Prevention

After identifying several alternative environmental management options, it is reasonable to ask why these options are not being implemented. What can be done to encourage their use? The following discussion summarizes the general findings based on an assessment of potential obstacles and incentives for implementing five highly ranked options. For more details, see Section 5.0.

A. EPA does not have an explicit policy goal and may not have the statutory authority to simply set a release reduction "target" without prescribing how this target should or could be met. When the target involves releases in multiple media, current administrative procedures discourage a coordinated approach, including evaluating risks, costs and benefits of managing residual pollutants in different media.

Requirements under many statutes and regulations prescribe how release reductions should be achieved, sometimes in terms of which technology should be used, often in terms of which specific sources should be controlled. For example, the Benzene Waste Operations NESHAP focuses on a specific emissions source to a single medium--benzene emissions from wastewater. The rule requires control of benzene emissions from this single source.

Data <u>from this refinery</u> indicated that wastewater is a small contributor to total benzene releases. Amoco and EPA disagree about some of the specific measurements and results. These are discussed in detail in Air Quality Data, Volume II (Amoco/EPA 1992b).

A number of pollution prevention approaches developed in this Project are more effective in controlling benzene emissions, and less costly to implement than the benzene NESHAP. Other refineries might find other sources that present more cost-effective control opportunities. Focusing on individual sources, rather than on desired overall "performance," limits the ability to achieve the most cost-effective control.

RCRA requires application of the Best Demonstrated Available Technology (BDAT) to a hazardous waste before it can be disposed. BDAT standards are typically based on a destruction technology rather than on methods at the higher end of the pollution prevention hierarchy.

One proposal now before Congress (S. 1081) to reauthorize the Clean Water Act would amend 304(b) of the Act and require EPA to promulgate effluent guidelines which reflect the application of best available control technology (BAT) for all categories of pollutants. This Congressional proposal, which does not reflect the Administration's position, could limit the Agency's ability to set environmental protection priorities.

B. Legislative and regulatory programs do not provide implementation schedules compatible with design, engineering, and construction timeframes.

Most regulatory and statutory programs require compliance within six months to at most three years after promulgation of a final rule. In some cases, compliance requirements do not consider normal maintenance schedules and economic penalties associated with facility-wide shutdowns. Consequently, short-term "fixes" which can meet legal deadlines, are used at the expense of more cost- and environmentally effective, long-term solutions.

A typical refinery project for processing oil using established technology and design procedures, normally takes 2-3 years from initial design to startup, assuming there is agreement on what to build, no unusual equipment delivery problems, no additional safety considerations, and no prolonged startup difficulties. Many projects take longer when regulatory applicability, scope or design criteria are unclear, or new technologies are involved.

For example, the benzene NESHAP rule discussed above was promulgated in March 1990 (under the 1977 Clean Air Act Amendments). Statutory language required compliance with the regulations within two years. In this case, significant differences in interpretation between EPA and the regulated community took more than one year to resolve and to clarify the regulatory requirements. An acceptable understanding is a prerequisite to engineering and construction. It was physically impossible to design, engineer, procure, construct, and start up the required control within the remaining one year compliance time frame.

C. Congress, EPA and much of industry have become used to command-and-control, end-of-pipe treatment approaches based on twenty years of experience. These well established problem solving approaches are difficult to change.

In the 1970's, environmental regulations successfully helped reduce point source emissions to air and water. End of pipe treatment was successful partly because many industrial firms and permitting authorities had little experience dealing with these problems, and found the specification of technical solutions offered a "road-map" for how to proceed along an uncharted course. These requirements also provided a relatively "level playing field" for US industry. Many of today's problems are sufficiently different than those of the early 1970's that they can benefit from alternative approaches.

D. The short time taken by the Virginia Air Pollution Control Board to issue or modify air permits is not a deterrent to installing technologies to reduce airborne emission at this site.

Most of the technical options would reduce air releases at the Refinery. However, obtaining permits to install most of these technologies would probably not be a problem since the Virginia Air Pollution Control Board is estimated to take about six months to issue a permit (Virginia is a delegated state for issuing air permits).

However, information generated through a facility-wide multi-media assessment is a necessary first step to not only developing a strategy to reduce these releases, but also to exploring such implementation options as integrated permits.

E. Inadequate accounting for both the benefits and costs of environmental regulations is an obstacle to developing a more efficient environmental management system. Responsibility for pollutant generation and accountability for environmental protection are difficult to quantify.

At many industrial plants, such as Amoco's, waste management costs are frequently charged to a central environmental management division rather than to the operating unit that generates the waste. Remediation costs for clean-up of contaminated soil, for example, are frequently charged against another cost center, rather than to the generator of the contamination. This separation between release generation and costs is a disincentive to manage releases more effectively.

Few EPA accounting systems measure direct benefits of the Agency's activities, such as improved ecological health, biodiversity, reduced risk to human populations, etc. Rather, accomplishments are usually measured in terms of activities such as permits written, amount of fines collected, or number of enforcement actions pursued. (GAO, 1991) The lack of direct connection between Agency activities and environmental results reduces accountability for program costs and benefits. Without adequate measurement systems, it is difficult to tell when environmental management practices actually improve the environment.

1.3.5. Education/Communications/Working Relationships

This Project enhanced knowledge of both government and industry, and generated information that EPA and Amoco can use.

The study provided an opportunity to educate individuals within EPA and Amoco. Based on plant visits and information exchanges, EPA personnel better understand how a refinery works, the complexities of the refining processes, and the difficulties in obtaining reliable environmental release data. This improved understanding will be useful as the Agency considers future data needs for regulatory development and permits.

Similarly, Amoco personnel better understand how EPA develops regulations, the type of information needed, and the Agency's operating constraints. This will be useful for Amoco in interacting with EPA and other government agencies.

The detailed release information developed in this Project could be useful to all three media offices: air, water, and solid waste.

- The Office of Air and Radiation may be able to use air monitoring and modeling information for developing MACT standards and improving emission factors.
- The Office of Solid Waste should be able to use sampling and monitoring information for characterizing RCRA Subtitle D wastes and management practices.
- The Office of Water should be able to use wastewater sampling information to evaluate Petroleum Refining effluent guidelines, and the biomarkers research results in evaluating aquatic health measurement tools.

The working relationships between various EPA offices, State and Amoco personnel were quite fragile when the Project began. Individuals brought their institutional viewpoints to initial discussions. By agreeing at the beginning of the Project that we may not necessarily agree with all findings and conclusions, people showed a willingness to discuss issues and focus on data and factual information. Many of the perceived and real differences in views were more easily dealt with in a factual setting.

1.4 Recommendations

1.4.1 Explore Opportunities to Produce Better Environmental Results More Cost-effectively.

Data from this study show that the Refinery can meet a release reduction goal more cost-effectively than by meeting reductions prescribed by current regulatory or legislative requirements.

For example, the ranking analysis shows that given the opportunity the Refinery could remove about 97 percent of tons of airborne hydrocarbons at about 25 percent of the cost of reducing them under current and anticipated regulations. The cost-effectiveness of the flexible option is about \$600/ton compared with the cost-effectiveness of \$2,400/ton for regulatory requirements.

EPA might evaluate options for setting a goal or target for reducing multi-media releases from a facility, and then allow the facility to develop an <u>alternative compliance strategy</u> to meet the goal. This alternative strategy would allow the facility to meet the goal at a lower cost, include interim milestones, and be enforceable. This strategy would also make appropriate information available to ensure that the reduction targets will be met.

This strategy might also include commitments to other environmental improvements such as cogeneration, additional reductions in releases, wetlands restoration, wildlife habitat enhancement, creation of new wetlands, controls on nonpoint sources of pollution, improved environmental data collection and research. The cost savings realized from meeting requirements under a more flexible approach make it possible to realize additional environmental benefits which are presently foregone because of the high costs of many regulatory programs.

1.4.2 Improve Environmental Release Data Collection, Analysis and Management.

Data from this study show that an emissions inventory could be improved by measuring releases and developing new emission factors. For example, the emissions inventory at the beginning of the project did not account for all potential releases to the environment. Some releases were excluded because the Agency has excluded them from reporting (e.g., barge loading operations); some releases were not included because the sources and the amount were thought by Amoco to be insignificant (e.g., blowdown stacks); some emissions were overestimated (e.g., API Separator); and some releases were underestimated (e.g., coker pond). Jointly established sampling and analysis protocols could help improve data quality, so that reported values more accurately portray facility releases.

Data currently collected in response to regulatory or permitting requirements could be evaluated to determine how its utility and quality might be improved. For example, TRI data quality and utility could be improved by:

- Providing more inclusive estimates of facility-wide releases to all media. The Project found the exclusion of marine loading operations from TRI reporting requirements conveyed an inaccurate picture of total facility releases.

- Reporting groups of chemicals, rather than individual species, especially if these chemicals have similar structural, physical and toxicological properties. Requiring reporting of all VOCs for refineries, rather than specific compounds like xylene (and its individual isomers), would provide a meaningful measure of refinery releases. That is because xylene poses approximately the same risks and has physical characteristics similar to the hundred of undifferentiated VOC compounds not covered in TRI. For a refinery, where a complex mixture of chemicals are released from most sources, tracking many separate chemicals does not make good use of technical, laboratory, and environmental management resources.

- Reporting other selected chemicals of concern for demonstrated human health or ecological impact separately. At a refinery, chemicals such as butadiene, benzene, and nickel may be good indicators of risk/release potential and management practices. Other industrial sectors would need to track different specific chemicals.

- Improving emission factors for estimating releases based upon information developed in this project, and additional work by EPA/industry task groups that could focus on the different data collection needs of discrete industry sectors.

The Project had great difficulty collecting and verifying environmental release data from the site. Emissions from these sources are complex and measurement techniques are rudimentary. Many emission measurements varied with time. For example, the Coker pond emissions varied by a factor of three within a few hours. Better sampling and analysis methods and statistical tools are needed to analyze variability. Research is also needed to develop methods that can verify release inventories within reasonable confidence limits, accounting for specific differences in emissions factors.

1.4.3 <u>Provide Incentives for Conducting Facility-wide Assessments, and Developing multi-media Release Reduction Strategies. Such Strategies Should Consider Multi-Media Consequences of Environmental Management Decisions</u>.

This Project demonstrates that more cost-effective environmental protection programs can be designed by allowing companies to consider site specific factors and focus on results.

A detailed facility-wide, multi-media assessment identified the most significant medium (air) and releases sources, both in terms of quantity <u>and</u> impact on the surrounding area. Specific technology options were then developed to deal with these sources. The significance of sources identified in this Project were not initially known or apparent to the participants. Proposed solutions could not have been developed in the absence of data which identified their importance.

For example, hydrocarbon emissions from barge loading operations (784 tons annually) and blowdown stacks (5,200 tons annually) are significant. However, the Refinery did not know this prior to this Project, nor did the existing regulations require the collection of this data. Thus, it did not develop control options to reduce these emissions.

Several technologies considered for reducing releases, transfer pollutants from one medium to another or convert pollutants to different forms. Since human health and environmental consequences vary from one medium to another, viewing a release problem in the context of net environmental effects is essential to developing more sound solutions.

The current institutional framework and procedures for developing regulations do not include multi-media assessments and analysis. Current practices should be reviewed to determine how they could be modified to use information from such assessments. An integrated pollution prevention and management strategy would facilitate development of release management options that produce better environmental results. (EPA/SAB, 1990a; EPA/SAB, 1990b; OMB, 1991)

At present, industry has little incentive to conduct such assessments because it does not have an opportunity to implement their findings.

1.4.4 Encourage Additional Public/Private Partnerships on Environmental Management.

The Yorktown experience demonstrates the opportunities and pitfalls that can occur when government and industry work together. The opportunities are significant. The pitfalls are worth overcoming. All organizations--EPA, Virginia and Amoco--sought to develop and test innovative environmental management approaches that, unlike most traditional "command and control" approaches, consider risk reduction, address multi-media concerns, maximize environmental benefits, encourage efficient use of resources, and promote facility-specific implementation choices. While it will take time and patience to overcome decades of distrust, such joint government/industry efforts can result in more cost-effective environmental protection by providing the opportunity to share different viewpoints and skills.

In this study, for example, EPA brought expertise on the type of information needed to develop regulations, and their operating constraints, while Amoco brought an understanding of refinery operations and economics. By helping to educate each other and develop a mutual understanding of issues and technology, Amoco, EPA and the Commonwealth of Virginia together agreed on the most significant emissions from the Refinery and the most promising approaches to reducing them.

Public/Private partnerships could also be used to leverage Agency resources for providing improved data needed to develop regulations. This Project illustrates a possible approach to collecting data, assessing technologies and characterizing a facility within an industry that took less time and Agency resources but relied more on private support.

1.4.5 Conduct Research on the Potential Health and Ecological Effects of VOCs.

The Refinery is a major source of the area's VOC emissions. However, information on the potential adverse health effects of VOC emissions is rather limited (Graham, 1991). Research is needed to better characterize health and ecological effects of VOCs that can be used in conducting risk assessments. This study could also build on efforts currently underway at the American Petroleum Institute, and the Chemical Industry Institute of Toxicology (CIIT) and others.

EPA should also undertake research to develop indicators that measure impacts on the ecosystem of multi-media releases from industrial facilities. This Project looked at several biomarkers that show promise as indicators in aquatic environments. Limited information and methods for assessing ecological risk limits the ability to conduct comprehensive risk assessments, and measure changes in environmental quality.

1.5 References

AIChE, 1985, **Guidelines for Hazard Evaluation Procedures**, American Institute of Chemical Engineers, New York, 1985.

Amoco/EPA, 1992b. "Air Quality Data, Volume II," prepared by D. N. Blewitt for the Amoco/USEPA Pollution Prevention Project, Chicago.

Amoco/EPA, 1991a. "Pollution Prevention Workshop," prepared by H. Klee, Jr. and SAIC for the Amoco/USEPA Pollution Prevention Project, Chicago.

Amoco/EPA, 1990. "Project Workplan," prepared by H. Klee, Jr. (Amoco) and M. Podar, (USEPA) for the Amoco/USEPA Pollution Prevention Project, Chicago.

API, 1991b. "The Generation and Management of Wastes and Secondary Materials in the Petroleum Refining Industry, 1987-88," American Petroleum Institute, Washington, D.C.

CAA, 1990. Clean Air Act Amendments of 1990, Conference Report 101-952, October 26, 1990.

Cohen, Y., Allen, D. T., Blewitt, D. N., and Klee, H., 1991. "A Multimedia Emissions Assessment of the Amoco Yorktown Refinery," presented at the 84th Annual Air and Waste Management Association meeting, Vancouver, Canada, June 17, 1991.

EPA/SAB, 1990a. "Reducing Risk: Setting Priorities and Strategies for Environmental Protection," United States Environmental Protection Agency, Washington, D.C.

EPA/SAB, 1990b. "The Report of the Strategic Subcommittee, Relative Risk Reduction Project, Reducing Risk, Appendix C," (EPA SAB-EC-90-021C), United States Environmental Protection Agency, Washington, D.C.

EPRI, 1983. "Economic Evaluation of FGD Systems," Project 1610-1, Electric Power Research Institute, Palo Alto, California.

Federal Register, 1990. "Benzene Waste Operations NESHAP," **Federal Register, 55**, 8292, March 7, 1990.

Graham, J. D. (ed), 1991. **Harnessing Science for Environmental Regulation**, Praeger, New York, 1991.

GAO, 1991. "Environmental Protection: Meeting Public Expectations with Limited Resources," General Accounting Office, (GAO/RCED-91-97), Washington, D.C., June, 1991, Chapter 3.

Los Angeles Times, 4/14/88. See Also, **Chicago Tribune**, 1/25/91, **Houston Post**, 9/3/88, **Philadelphia Inquirer**, 4/29/88, and **Seattle Times**, 2/25/91.

NRC, 1990. **Tracking Toxic Substances at Industrial Facilities: Engineering Mass Balance versus Materials Accounting**, National Research Council, National Academy Press, Washington, D.C.

OMB, 1991. "Budget of the United States Government, Fiscal Year 1992, Section IX.C. Reforming Regulation and Managing Risk-Reduction Sensibly," Office of Management and Budget, Washington, D.C., February 4, 1991.

Table 1.1

Project Components

Biomarkers
Chemical Fate and Transport
Communications
Cost Estimation
Decision Making Methodology
Engineering
Environmental Impact
Exposure Modeling
Facilities Management
Group Dynamics
Meteorology
Public Perceptions
Regulatory/Legislative Policy
Risk Assessment
Sampling
Source Identification

Table 1.2

Participants in the AMOCO/EPA Pollution Prevention Project

U.S. Environmental Protection Agency

Office of Air and Radiation
Office of Solid Waste and Emergency Response
National Advisory Council on Environmental Policy and Technology
Office of Research and Development
Office of Policy, Planning and Evaluation
Office of Water
Office of Pesticides and Toxic Substances
Office of Air Quality Planning and Standards
Region III

Amoco Corporation

Environmental Affairs and Safety
Public and Government Affairs
Art Services
Analytical Services
Groundwater Management Services

Amoco Oil Company

Refining and Transportation Engineering
Research and Development
Yorktown Refinery
Whiting Refinery

Commonwealth of Virginia

State Water Control Board
Department of Waste Management
Department of Air Pollution Control

Academic Institutions

Virginia Institute of Marine Science, College of William and Mary
University of California at Los Angeles
University of Michigan

Table 1.2 (Continued)

Consultants

ICF/Clement International
Research±able
ENSECO Laboratories
Radian Corporation
Linnhoff-March
York Laboratories
Murry/Trettel Consulting Meteorologists
Industrial Marine Service, Inc.
James R. Reed and Associates
Industrial Economics, Incorporated
Abt Associates
Resources for the Future

Peer Review Committee Members

Dr. Clifford S. Russell, Vanderbilt Institute for Public Policy Studies (Chair)
Ms. Jolene Chinchilli, Chesapeake Bay Foundation
Mr. A. Ray Dudley, Array Enterprises, Inc.
Dr. John R. Ehrenfeld, MIT Center for Technology, Policy and Industrial Development
Dr. John D. Graham, Harvard School of Public Health
Dr. Robert J. Huggett, Virginia Institute of Marine Science
Ms. Frances H. Irwin, Conservation Foundation
Dr. Joseph F. Malina, Jr., University of Texas
Dr. John J. McKetta, University of Texas
Mr. David R. Patrick, Clement International Corporation
Dr. James G. Quinn, University of Rhode Island
Dr. Mitchell J. Small, Carnegie Mellon University

Amoco/USEPA Workgroup Members

John Atcheson
David Berg
Doug Blewitt
Walter Brodtman
Kirt Cox
Catherine Crane
Jim Cummings-Saxton
Christine E. DeLuca
Dan Fort
Deborah Gillette
Madeline Grulich
Deborah Hanlon
Janice Johnson
Mark Joyce
Sharon Keneally-Baxter
Mark Klan
Howard Klee
Donna Kraisinger
Jim Lounsbury
Keith Mason
Richard Olin
Pat Pesacreta
Mahesh Podar
Alex Ross
Manik Roy
Marv Rubin
Dale Ruhter
Debora Sparks
Mary Spearman
Pat Woodson

Table 1.3

Comparison of Different Environmental Management Options for the Yorktown Refinery

Selection Criteria for Release Reduction Projects	No. of Projects	Material Released (Note 1)	Total Release Reduction Tons/Yr.	Capital Cost $MM	Annual Cost $MM	Benzene Exposure Reduction, %	Average Cost $/Ton
1. Current and Expected Regulatory Requirements (Table 4.5) (Note 3)	8	VOC/HC	7,300	53.6	17.5	99	2,400
2. Cost-Effective Release Reduction (Table 4.6)	6	VOC/HC Listed HW	7,500	10.7	3.8	87	510
3. Cost-Effective Benzene Exposure Reduction (Table 4.7)	6	VOC	7,100	13.2	4.2	90	590
4. Multiple Criteria (Table 4.4) (Note 4)							
4a. Work Group (Top 4)	4	VOC	Four options were consistently selected as most effective in different ranking exercises.				
4b. Amoco (Top 4)	4	VOC					
4c. EPA/Virginia (Top 4)	4	VOC					
5. Most Favored--All Rankings, All Evaluators (Table 4.8)	4	VOC	6,900	10.2	3.5	87	510

Notes:

1. VOC = Volatile Organic Compounds
   HC = Liquid Hydrocarbons
   Listed HW = Solid, Hazardous Waste

2. Values are rounded. See tables 4.1 through 4.7 for details.

3. Regulatory and Statutory Programs considered include Benzene NESHAP, Ozone non-attainment, likely Clean Air Act requirements under MACT and HON rules.

4. Multiple criteria included release reduction potential, benzene exposure reduction potential, cost, impact on liability, transferability to other facilities, status in pollution prevention hierarchy, etc. See Section 4.0 for discussion.

Table 3.2

Selected Pollution Prevention Engineering Projects

The following projects were identified for further study as a result of the Pollution Prevention Workshop in Williamsburg and subsequent Workshop meetings.

1. Reroute Desalter Effluent: Hot desalter effluent water currently flows into the process water drainage system at Combination unit. This project would install a new line and route this stream directly to the API Separator. This reduces volatile losses from the sewer system by reducing process sewer temperature and oil content. Volatile losses at the API Separator increase slightly.

2. Improve Desalter System: Evaluate installation of adjunct technology (e.g., centrifuge, air flotation, or other technology) on desalter water stream prior to discharge into the underground process drainage system. This reduces oil and solids waste loads in the sewer system, affecting the waste water treatment plant and volatile losses from the drainage system.

3. Reduce FCU Catalyst Fines: Evaluate possible performance of more attrition resistant FCU catalyst to reduce fines production. (Subsequent review with catalyst vendors indicated the Refinery was already using the most attrition resistant catalyst available.) Two other fines reduction options were considered.

3a. Replace FCU Cyclones: Assess potential for reducing emissions of catalyst fines (PM10) by adding new cyclones in the regenerator.

3b. Install Electrostatic Precipitator at FCU: Assess potential of electrostatic precipitator in reducing catalyst fines (PM10) emissions.

4. Eliminate Coker Blowdown Pond: Change operating procedures for coke drum quench and cooldown so that an open pond is no longer needed. This reduces volatile losses from the hot blowdown water.

5. Install Seals on Storage Tanks: Double seals or secondary seals will reduce fugitive vapor losses. Recovery efficiency varies from tank to tank, depending on the hydrocarbon stored and construction details. Table 3.3 provides additional information.

5a. Secondary Seals on Gasoline Tanks: Secondary rim mounted seals on tanks containing gasoline.

5b. <u>Secondary Seals on Gasoline and Distillate Tanks</u>: Secondary rim mounted seals on tanks containing gasoline and distillate material.

5c. <u>Secondary Seals on ALL Floating Roof Tanks</u>: Secondary rim mounted seals on all floating roof tanks.

5d. <u>Option 5c + Internal Floaters on Fixed Roof Tanks</u>: Secondary rim mounted seals on floating roof tanks and the installation of a floating roof with a primary seal on all fixed roof tanks.

5e. <u>Option 5d + Secondary Seals on Fixed Roof Tanks</u>: Secondary rim mounted seal on all floating roof tanks and the installation of a floating roof with a primary and secondary seal on all fixed roof tanks.

6. <u>Keep Soils out of Sewers</u>: Use road sweeper to remove dirt from roadways and concrete areas which would otherwise blow or be washed into the drainage system. Develop and install new sewer boxes designed to reduce soil movement into sewer system, particularly from Tankfarm area. Estimate cost for installation on a Refinery wide basis. Both items reduce soil infiltration, in turn reducing hazardous solid waste generation.

7. The Benzene Waste Operations NESHAP requires control of benzene emissions from refinery wastewater sources. Three separate projects (7A, 7B, and 7C) were identified to meet these requirements. Specific design and construction features of these projects will aid with meeting <u>anticipated</u> requirements of some future regulations, such as storm water permitting, RCRA corrective action, the Primary Sludge rule and land disposal restrictions.

7A. <u>Drainage System Upgrade</u>: Install above-grade, pressurized sewers, segregating storm water and process water systems.

7B. <u>Upgrade Process Water Treatment Plant</u>: Replace the API Separator with a covered gravity separator and air floatation system. Capture hydrocarbon vapors from both units.

7C. <u>Convert Blowdown Stacks</u>: Replace existing atmospheric blowdown stacks with flares. This reduces untreated hydrocarbon losses to the atmosphere, but creates criteria pollutants.

8. <u>Change Sampling Systems</u>: Install flow-through sampling stations (speed loops) where required on a refinery-wide basis. These replace existing sampling stations and would reduce oil load in the sewer or drained to the deck.

9. Reduce Barge Loading Emissions: Estimate cost to install a marine vapor loss control system. Consider both vapor recovery and destruction in a flare.

10. Sour Water System Improvements: Sour water is the most likely source of Refinery odor problems. Followup on projects previously identified by Linnhoff-March engineering to reduce sour water production, improve sour water stripping.

11. Institute LDAR Program: Institute a leak detection and repair program for fugitive emissions from process equipment (valves, flanges, pump seals, etc.) and consider costs and benefits.

11a Annual LDAR Program with a 10,000 PPM hydrocarbon leak level

11b. Quarterly LDAR Program with a 10,000 PPM hydrocarbon leak level

11c. Quarterly LDAR Program with a 500 PPM hydrocarbon leak level

Figure 2.2

Pollution Prevention Sampling Program

(Number of Samples)

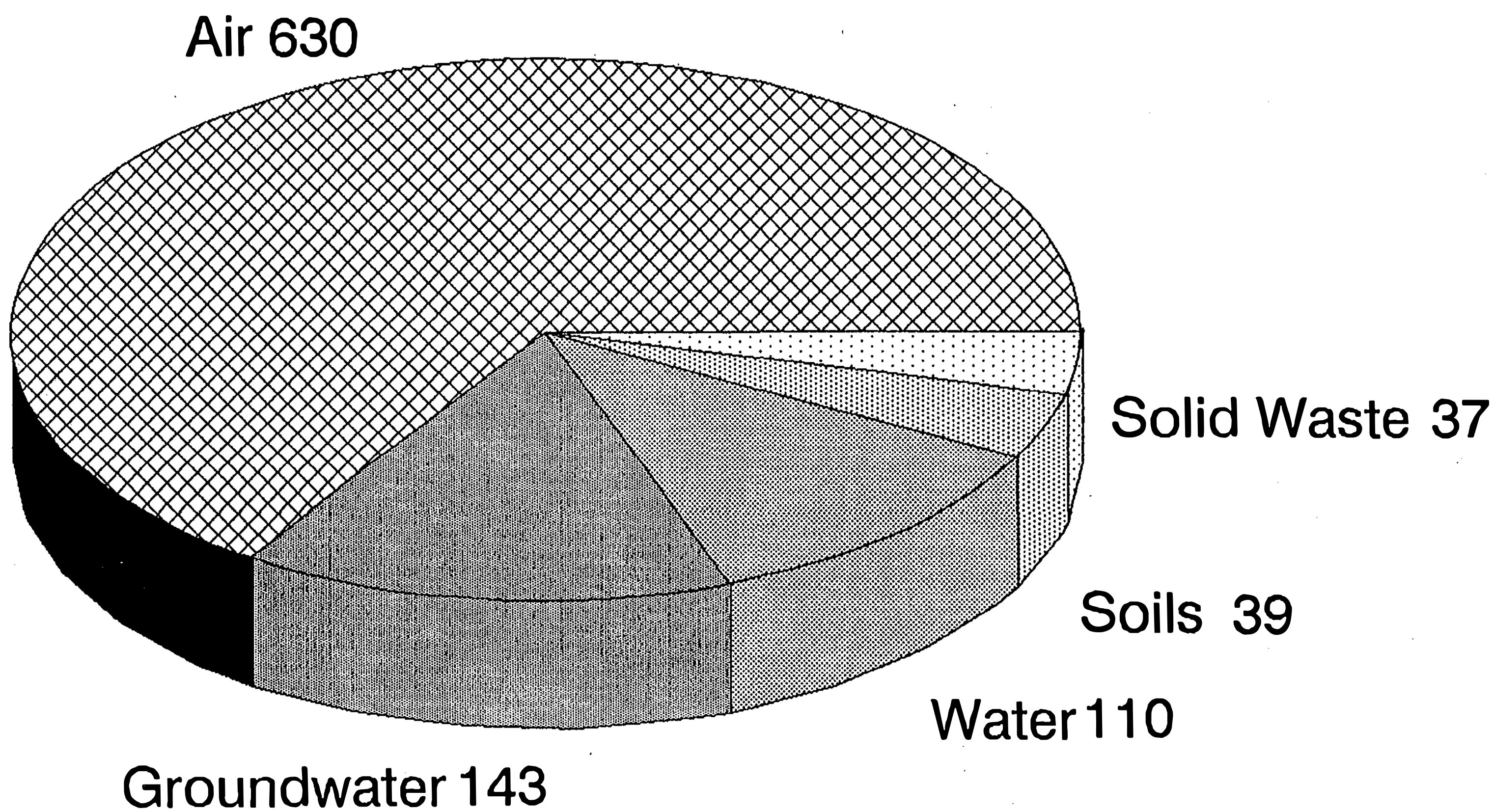


Figure 2.4

Pollutant Transfers/Recycle/Treatment within the Yorktown Refinery

(Units are tons per year)

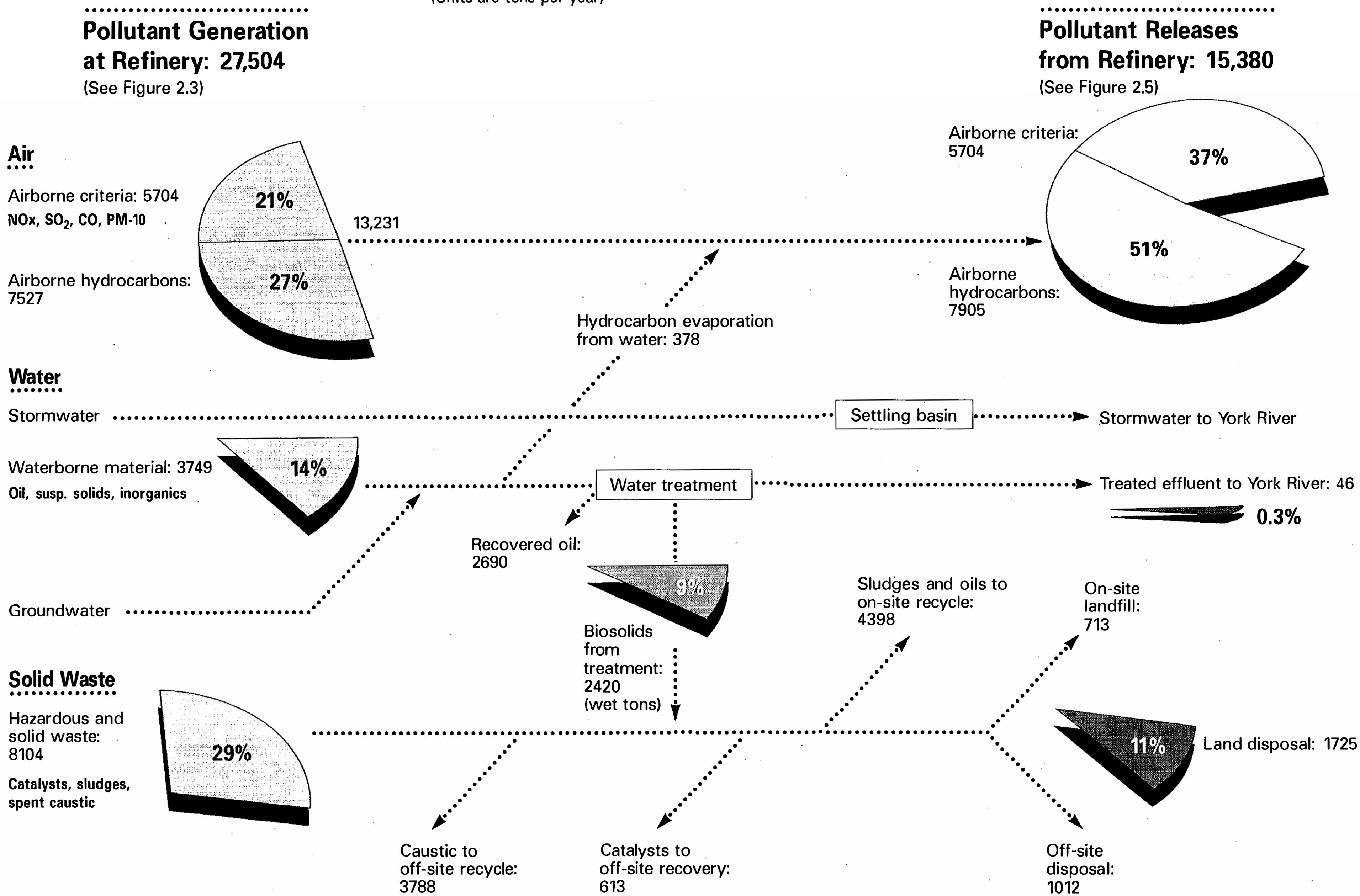
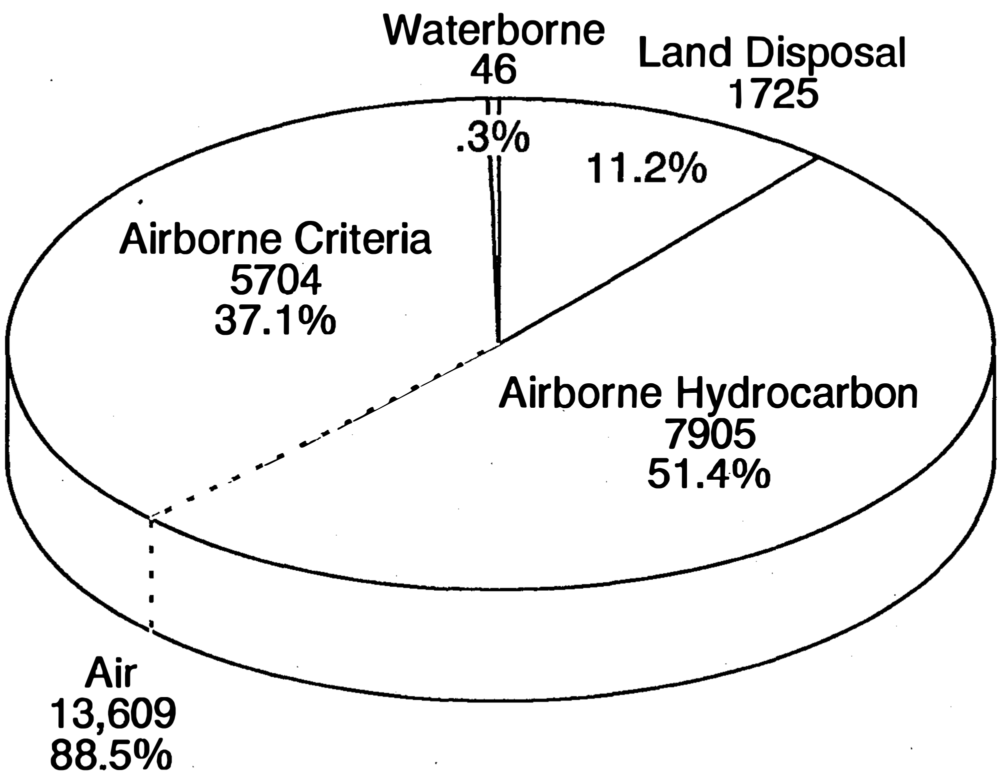


Figure 2.5

Total Releases Entering the Environment from Yorktown Refinery



Units are Ton/year

Total Releases = 15380 tons/year

Figure 2.7

1989 TRI Inventory Compared to Measured Emissions

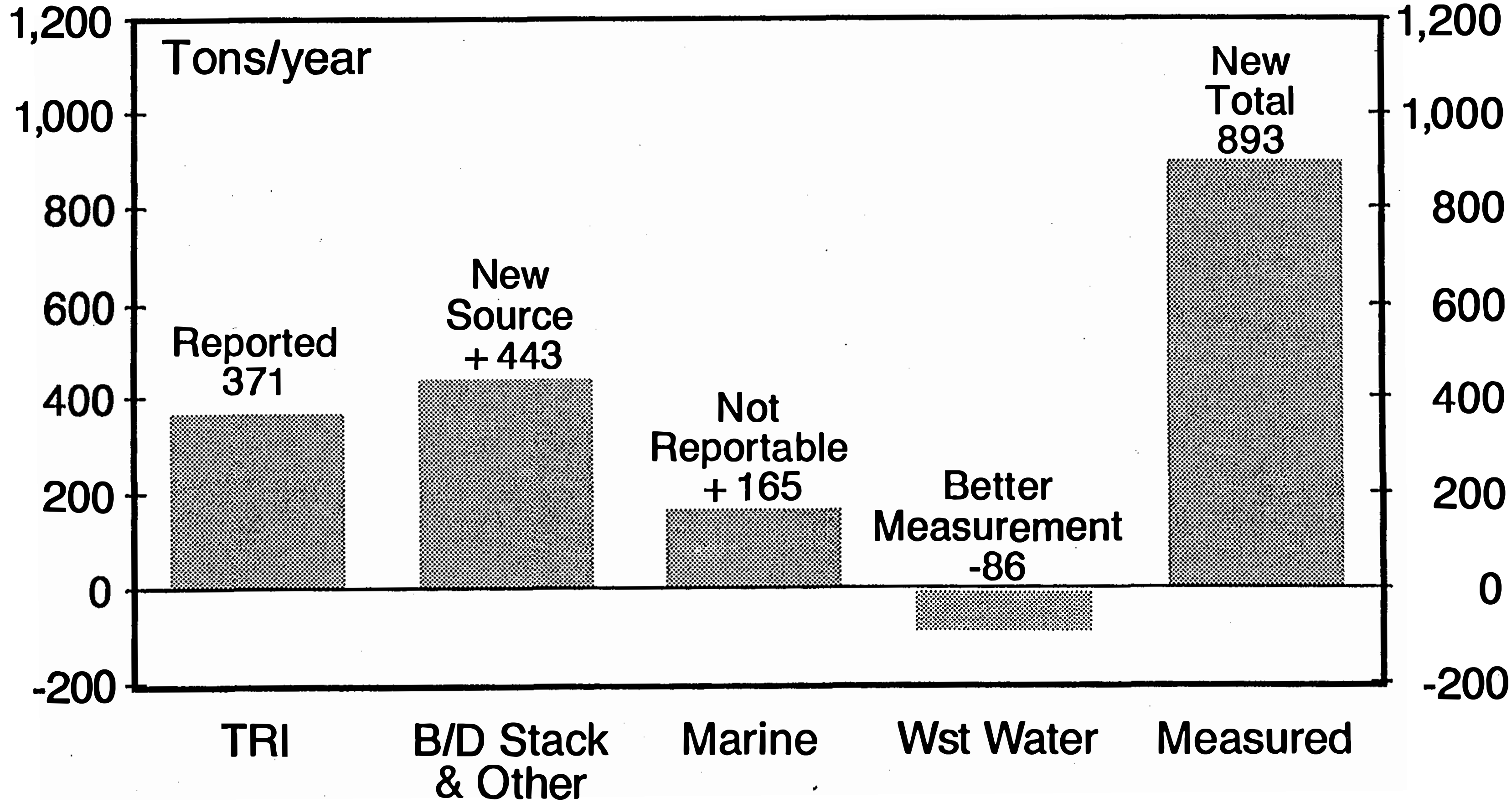
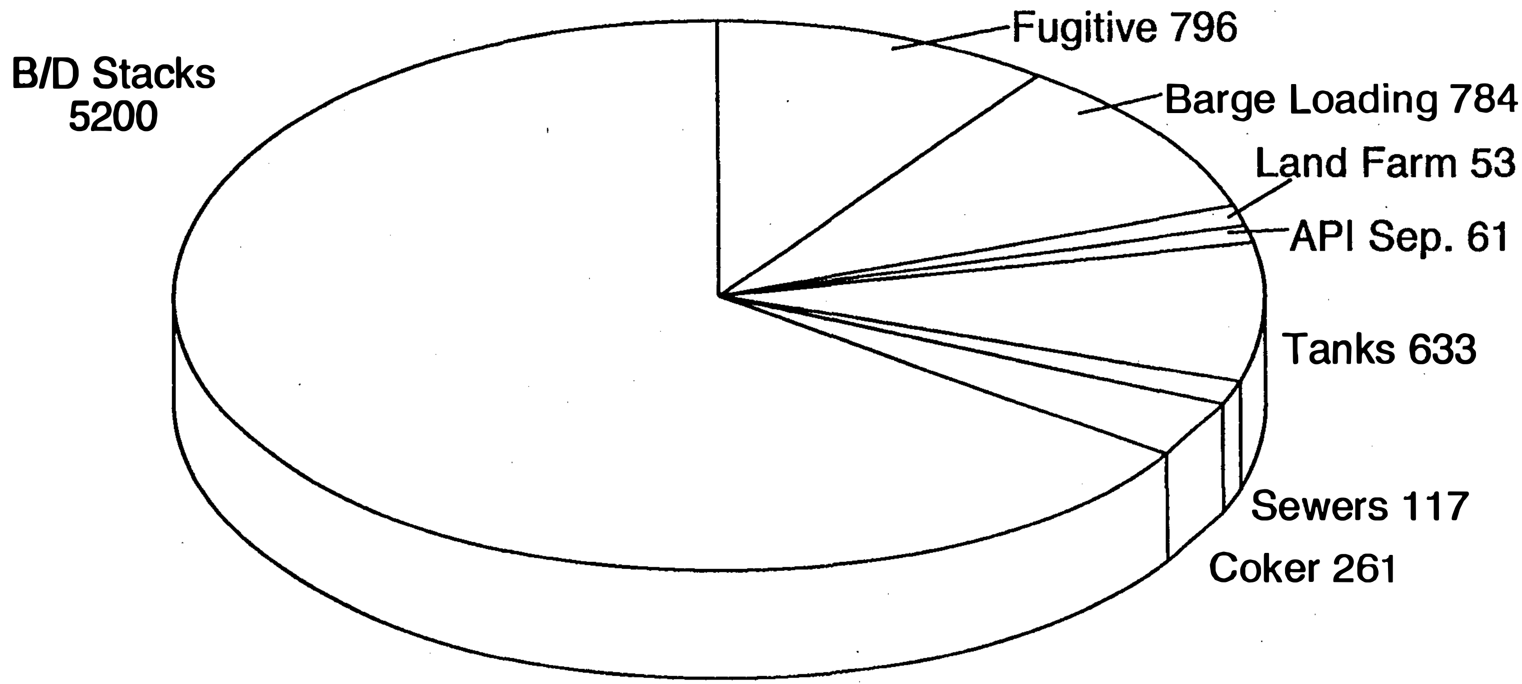


Figure 2.9

Yorktown Refinery
Airborne Hydrocarbon Sources



Units are tons/year   Total = 7905

Figure 3.1

Yorktown refinery

Simplified Flow Diagram with Release Sources and Control Options

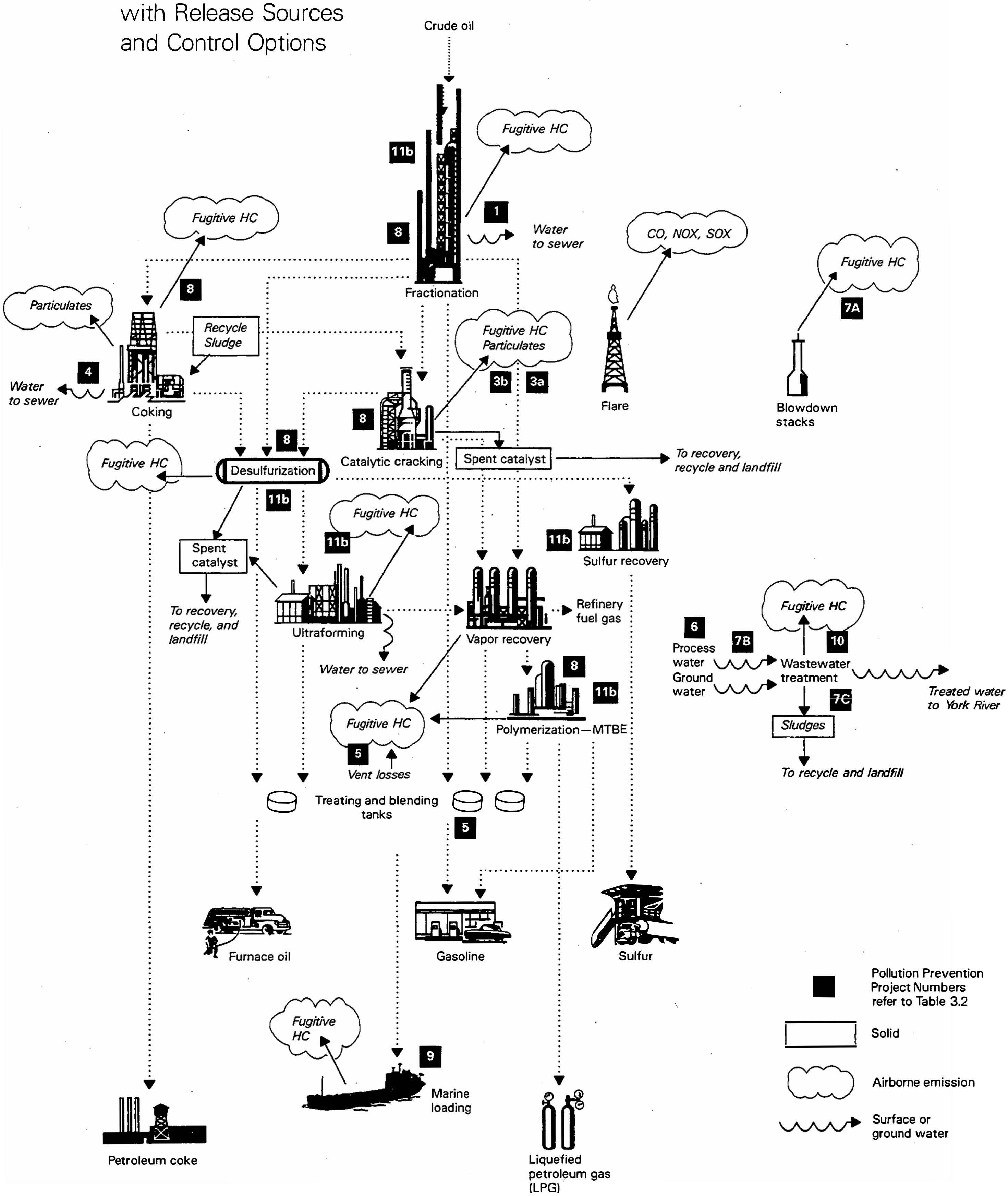


Figure 3.4
Histogram of Benzene Emissions With and Without Marine Loading Controls

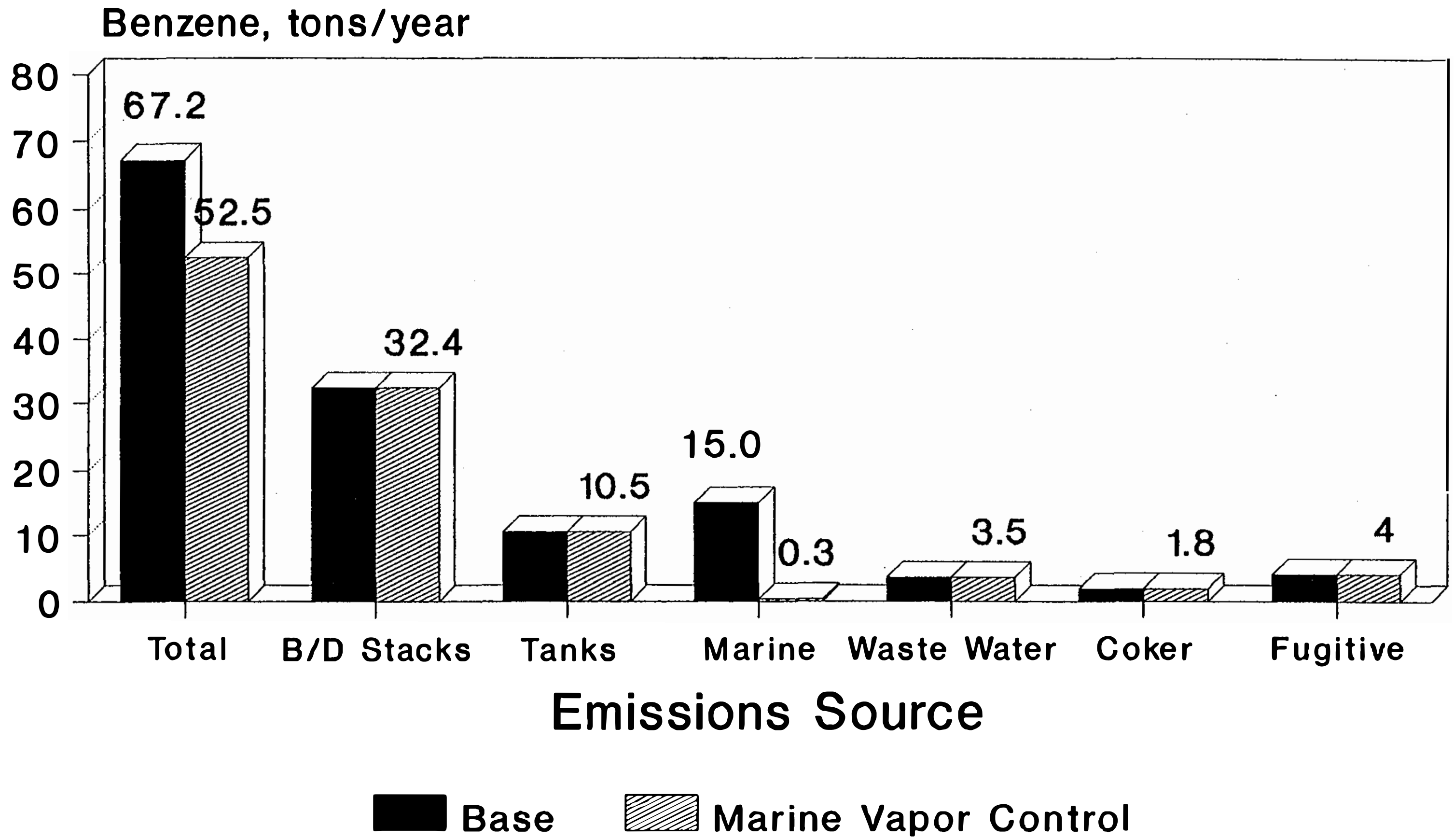
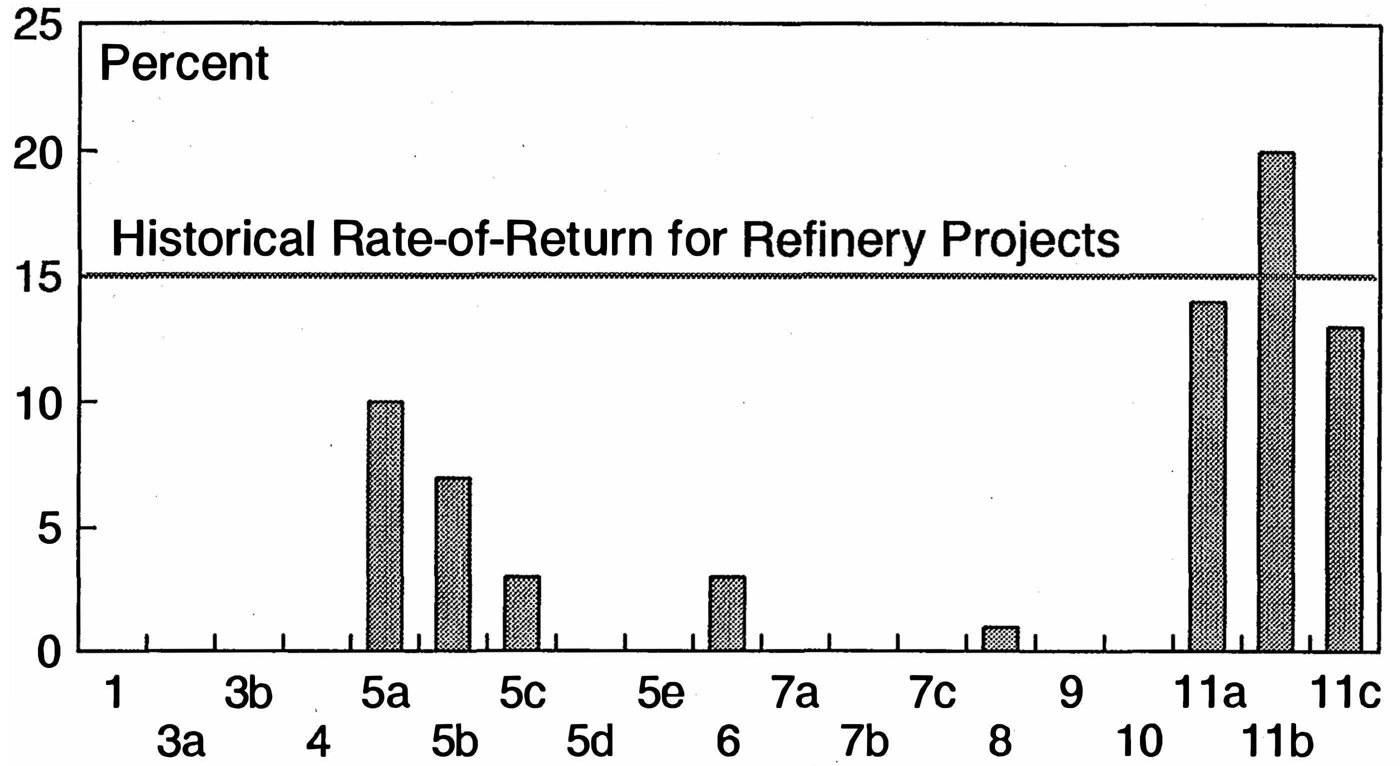


Figure 3.9

Projected Rates of Return Pollution Prevention Projects - Yorktown



Project Number

(See Table 3.2 for Descriptions)

Notes 1. Projects for which no values are shown have negative returns.

2. Rate of return is the rate at which benefits and costs are equal for the life of the project.

APPENDIX C

PROJECT DOCUMENTATION

Summaries and details of the Amoco/EPA Yorktown Pollution Prevention Project are documented in 21 volumes of data, information, findings, and comments, etc. All of these volumes have been made available for purchase through NTIS, the National Technical Information Service. Orders may be placed by contacting:

National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161

Telephone number (703) 487-4650

A list of the NTIS document numbers and a description of each volume follows.

AMOCO/USEPA YORKTOWN POLLUTION PREVENTION PROJECT
NTIS DOCUMENT NUMBERS

PB92228519	EXECUTIVE SUMMARY
PB92228527	PROJECT SUMMARY
PB92228535	PROJECT WORKPLAN
PB92228543	POLLUTION PREVENTION WORKSHOP
PB92228550	REFINERY RELEASE INVENTORY
PB92228568	SOLID WASTE DATA
PB92228576	GROUNDWATER & SOIL DATA
PB92228584	SURFACE WATER DATA
PB92228592	AIR QUALITY DATA, VOLUME I
PB92228600	AIR QUALITY DATA, VOLUME II AIR QUALITY DATA, VOLUME II, APPENDICES A, I & J
PB92228618	PROJECT PEER REVIEW
PB92228626	PROJECTS, EVALUATION AND RANKING
PB92228634	ECOLOGICAL IMPACTS
PB92228642	PUBLIC PERCEPTIONS
*PB92228659	RISK ASSESSMENT METHODOLOGY AND RESULTS
*PB92228667	SUPPLEMENTARY INFORMATION
**PB92228691	AIR QUALITY DATA, VOLUME II, APPENDIX B-BENZENE & TOLUENE
**PB92228709	AIR QUALITY DATA, VOLUME II, APPENDIX B-ETHYLBENZENE & XYLENE
**PB92228717	AIR QUALITY DATA, VOLUME II, APPENDICES C, D AND E
**PB92228725	AIR QUALITY DATA, VOLUME II, APPENDIX F
**PB92228733	AIR QUALITY DATA, VOLUME II, APPENDICES G AND H

*INCOMPLETE AS OF 9/93

THESE APPENDICES (large computer outputs of data modelling**) ARE NOT SET UP FOR DISTRIBUTION

AMOCO/USEPA YORKTOWN POLLUTION PREVENTION PROJECT DOCUMENT ABSTRACTS

PB92228519 - EXECUTIVE SUMMARY

This volume summarizes results and policy alternatives identified during a 2-year pollution prevention study of Amoco Oil Company's Yorktown Virginia Refinery, jointly sponsored as a cooperative effort of Amoco Corporation and the United States Environmental Protection Agency. A significant finding of the study was that at this facility, current and expected environmental regulatory requirements can be achieved for 20-25% of the cost of current mandated approaches. Major recommendations are: (1) Government and industry need to explore opportunities to produce better environmental results more cost effectively; (2) We need to improve environmental release data collection, analysis, and management; (3) EPA should provide incentives for conducting facility-wide assessments and developing multi-media release reduction strategies; (4) We should encourage additional public/private partnerships on environmental management issues; (5) EPA and the petroleum industry should conduct research on the potential health and ecological effects of VOCs and reformulated gasolines.

PB92228527 - PROJECT SUMMARY

This volume summarized data obtained and analyses conducted during a 2-year pollution prevention study of Amoco Oil Company's Yorktown Virginia Refinery. A multi-media sampling program was used to identify potential pollution sources within the Refinery. Specific engineering projects were proposed to deal with major sources, and the simulated results of implementation were assessed in terms of environmental impact, cost, risk reduction for people living near the facility, liability, etc.

PB92228535 - PROJECT WORKPLAN

This volume provides a detailed workplan for obtaining data and analyzing results for a 2-year pollution prevention study of Amoco Oil Company's Yorktown Virginia Refinery. The goals of the study include (1) a multi-media inventory of all releases entering the environment from the Refinery, (2) development of possible engineering options to reduce the releases, (3) analysis of each option in terms of release reduction potential, impact on human health risk, ecological impact, changes in future liability, etc., and (4) identification of obstacles and incentives for implementation of any of the options considered.

PB92228543 - POLLUTION PREVENTION WORKSHOP

This volume documents the workshop held in Williamsburg, VA, on March 25-27, 1991, to review multi-media (air, water, land) data on environmental releases from Amoco Oil Company's Yorktown Virginia Refinery. Following the data review and a Refinery tour, breakout sessions were held to brainstorm on various topics including (a) process changes to reduce emissions, (b) groundwater protection, (c) criteria for ranking alternatives, (d) permitting issues, (e) general obstacles and incentives, and (f) maintenance and operating practices. This document provides presentation materials and notes from each breakout session.

PB92228550 - REFINERY RELEASE INVENTORY

This volume summarizes physical data obtained during a 2-year pollution prevention study of Amoco Oil Company's Yorktown Virginia Refinery. A multi-media sampling program was used to identify potential pollution sources within the Refinery. Sampling and analysis included air, surface water, groundwater, and solid waste data. Public perceptions about environmental issues of concern in the vicinity of the Refinery were also surveyed. The inventory showed that nearly 90% of the releases were airborne at this facility. Most of the remainder involved land disposal of solid wastes. Specific sources of major pollutants are identified.

PB92228568 - SOLID WASTE DATA

This volume summarizes the solid waste emissions inventory, solids source identification, and the solid waste sampling program that was conducted at the Amoco Yorktown Refinery on September 25-27, 1990, in support of the Pollution Prevention Project.

Major findings showed that the majority of solid waste generation occurs as "end-of-pipe" solids resulting from the treatment of wastewaters from the refinery sewer. Based on a regression analysis of the composition data for samples collected during this project, major upstream contributors to these solids appear to be soils. Solids from process units are also significant contributors.

PB92228576 - GROUNDWATER & SOIL DATA

This volume summarizes the evaluation of potential sources and sinks of groundwater contamination to determine the effects of the Yorktown refinery on the subsurface. Subsurface characterization of the refinery included an extensive subsurface sampling program that included 39 soil borings, 181 monitoring wells, and 23 surface water sampling points. Groundwater flow was modeled using FTWORK, a modification of MODFLOW.

Results showed that, due to above-ground process piping, contamination at the Yorktown Refinery was significantly less than that observed at other refineries. Free-phase hydrocarbons were only detected in one monitoring well. Metals contamination was limited to monitoring wells associated with historic waste management activities at the east end of the refinery. Contamination was detected in monitoring wells located adjacent to process units but affects were limited due to the process sewer acting as a collection point.

PB92228584 - SURFACE WATER DATA

This report summarizes the surface water sampling program at the Amoco Refinery at Yorktown, Virginia. The surface water data provides a snapshot of surface water pollutant generation and discharge from the refinery. Different process units contribute to the total wastewater flow of 460 GPM in the refinery. Water in the ditch system, which is non-process water, is free of organic contamination. Oil and grease, phenols, ammonia and sulfides are the significant components measured in the process wastewater. The concentrations of organics in most water streams leaving the individual process units are relatively low, in the 1-5 parts per million (ppm) range. However, extended contact of oil and water in the sewers increases the organic loading. A few individual streams such as the crude desalter brine and tank water draws have high pollutant loadings. Concentrations of metals in the refinery wastewater are very low. The wastewater treatment plant is very effective in reducing the pollutant loading in the water with overall removal efficiencies greater than 99% for most organics and inorganics.

PB92228592 - AIR QUALITY DATA, VOLUME I

This volume summarizes the measurement activities performed by Radian Corporation to quantify airborne organic vapor emissions. Radian conducted 3 measurement tasks concurrently during the period September 25 - October 1, 1990. The data from these activities were used to explore pollution prevention options and the impact these options could have on human and environmental exposure to airborne emissions. In addition to sampling ambient air, specific emission sources--the oil/water (API) separator, underground sewer, blowdown stacks and water ponds--were also tested. Most sampling examined benzene, toluene, xylene, and ethylbenzene emissions.

PB92228600 - AIR QUALITY DATA, VOLUME II
AIR QUALITY DATA, VOLUME II, APPENDICES A, I & J

This volume defines baseline air quality in terms of air emissions and ambient air quality. This baseline was used to evaluate potential impact of different pollution prevention options. The objectives of this study were to: 1) quantify current air emissions from the facility; 2) quantify ambient air quality impacts of these emissions; and 3) identify benefits of implementing pollution prevention alternatives or additional control measures.

Extensive computer modeling of the airshed immediately around the Refinery was conducted using the ISC Short-Term model with approximately 80 on-site emission sources and 8700 hourly meteorological data points.

This volume also includes:

Appendix A, which contains the analysis of tracer data used to evaluate fugitive emissions in the ultraformer unit area.

Appendix I, a summary of wind persistence data.

Appendix J, which contains Amoco responses to USEPA comments on the project's emission measurement techniques, data, etc.

PB92228618 - PROJECT PEER REVIEW

This volume documents the Peer Review process and comments received on various aspects of the AMOCO/USEPA Pollution Prevention Project conducted at Amoco Oil Company's Yorktown Virginia Refinery. An external Peer Review was an integral part of the Project to provide a 3rd-party view of technical and scientific issues, as well as comments on potential policy implications. Reviewers were selected and meetings organized by Resources for the Future, based in Washington, DC. Many of the reviewers had academic backgrounds, although representatives from environmental and industrial consulting organizations were also included. Three full-day meetings were held during the 2-year project to review (1) the Workplan, (2) sampling results, and (3) project results and conclusions.

PB92228626 - PROJECTS, EVALUATIONS AND RANKING

This volume describes the methodologies used to evaluate and rank the cost and effectiveness of each of the pollution prevention projects suggested for future investigation by the project workgroup. The report includes a third-party assessment (by IEC) to compare the different evaluation methodologies used by Amoco and the EPA.

PB92228634 - ECOLOGICAL IMPACTS

This volume includes the findings of a two-phase (laboratory and field) assessment of the potential use of biomarkers to evaluate the impact of the Refinery effluent on the York River. In the laboratory phase of the study, several of the biomarkers tested responded to various dilutions of process water effluent in an apparent dose-dependent manner. In the field study, however, there was little evidence that similar exposure is occurring in fish collected from the York River mainstream. The field data did suggest PAH exposure in fish collected from the stormwater settling pond and perhaps from the creek below the pond. Further studies are needed to evaluate the usefulness of those assays in future biomonitoring studies.

Also included in this volume are a characterization of the York River and several previous field studies of benthic community response to the Refinery effluent, where impacts have been difficult to detect.

PB92228642 - PUBLIC PERCEPTIONS

This volume provides data obtained from interviews, focus groups and a telephone survey about environmental issues of concern for people living in the vicinity of Amoco Oil Company's Yorktown Virginia Refinery. Major concerns identified were related to land development and infrastructure support. The Refinery has a relatively low profile in the area. The most serious environmental concern identified was the management of municipal and industrial solid waste.

PB92228659 - RISK ASSESSMENT METHODOLOGY AND RESULTS
(incomplete as of 9/93)

This volume includes the third party assessment (performed by ABT, Inc.) of the relative risk that the refinery may have on the surrounding area. The primary focus of the assessment is airborne releases.

PB92228667 - SUPPLEMENTARY INFORMATION
(incomplete as of 9/93)

This volume includes data collected subsequent to the completion of the project study, which is integrally related to the study. Two such investigations include 1) additional testing of the blowdown stacks which showed significantly lower emissions; and 2) analysis on the sediment in the stormwater surge basin and a assessment of its effect on fish living in the basin.

PB92228691 AIR QUALITY DATA, VOLUME II, APPENDIX B-BENZENE & TOLUENE
PB92228709 AIR QUALITY DATA, VOLUME II, APPENDIX B-ETHYLBENZENE & XYLENE

The two volumes above contain the ISCST modeling results of BTEX emission monitoring data.

PB92228717 AIR QUALITY DATA, VOLUME II, APPENDICES C, D AND E

This volume includes the following appendices:

Appendix C - Summary of modeling and monitoring comparisons
Appendix D - Annual modeling for BTEX
Appendix E - Culpability Analyses for BTEX

PB92228725 AIR QUALITY DATA, VOLUME II, APPENDIX F

This volume includes the annual modeling analyses for SARA Chemicals.

AIR QUALITY DATA, VOLUME II, APPENDICES G AND H

This volume includes the following appendices:

Appendix G - Culpability Analyses for SARA Chemicals
Appendix H - Modeling Analyses for criteria pollutants

R. E. Schmitt 9/93


recycled paper