EXECUTIVE SUMMARY

Section 112 of the Clean Air Act (CAA) lists source categories of major and area sources of hazardous air pollutants (HAPs) for which regulations must be developed. The U.S. Environmental Protection Agency (EPA) is currently preparing a National Emission Standard for Hazardous Air Pollutants (NESHAP) for emission sources in petroleum refineries. Before promulgating a NESHAP, it is necessary to perform an economic impact analysis , including an initial Regulatory Flexibility Analysis, on the affected industry.

The refining industry has developed a complex variety of production processes used to transform crude oil into its various final forms, many of which are already subject to some CAA controls. Section 112 of the CAA identifies HAPs for which EPA has published a list of source categories that must be regulated. Refinery HAP sources include process vents at fluid catalytic cracking units, catalytic reforming units, and sulfur plant units. None of these sources is currently controlled by existing NESHAPs. The subject NESHAP will therefore regulate emissions from these refinery sources.

The proposed NESHAP considered in this report represents the maximum achievable control technology (MACT) floor for all affected source types. The MACT floor is the level control that is the minimum stringency for a NESHAP that can be developed in accordance with Section 112(d) of the Clean Air Act.

The petroleum refining industry is currently affected by a previous NESHAP promulgated in August of 1995. While the full impacts of this previous regulation have not yet occurred (full implementation is expected by August, 1998), virtually all refineries in the industry are expected to be affected.

EIA OBJECTIVES

The primary objective of this analysis is to describe the magnitude and distribution of adverse impacts associated with proposed NESHAP among various members of society. This study estimates the costs to society and describes the adverse impacts associated with the subject NESHAP. Those members of society who could potentially suffer adverse impacts include:

- Producers whose facilities require emission controls.
- Buyers of goods produced by industries requiring controls.
- Employees at plants requiring controls.
- Individuals who could be affected indirectly such as residents of communities proximate to controlled facilities, and producers and employees in industries that sell inputs to or purchase inputs from directly affected firms.

BACKGROUND

Affected Market

Currently about 90 firms operate more than 160 petroleum refineries in 33 States in the U.S.[1] The combined estimated crude processing capacity of these refineries is approximately 15.4 million barrels per calendar day (b/cd). Three states, California, Louisiana and Texas dominate the domestic petroleum refining industry. Together, 60 refineries in these three states account for about 46 percent of domestic crude capacity. Also, the corporate headquarters of many firms operating refineries are located in these three states.

[1] A survey published in the Oil & Gas Journal (1996) lists 163 refineries operating as of January 1, 1997. In addition, there are a few operating refineries not listed in the survey. This analysis includes 164 U.S. refineries.

Emission Sources

The HAP emission sources of interest for the subject NESHAP are the process vents for fluid catalytic cracking units (CCRs), catalytic reforming units (CRUs), and sulphur recovery units (SRUs). HAP emissions from CCUs include metal HAP that are deposited on the catalyst particles and organic HAP that result from incomplete combustion. CRU process vent emissions can occur at three different points. These are the initial depressurization and purge vent; the coke burn pressure control vent; and the final catalyst vent. The HAP emissions of SRU process vents include carbonyl sulfide (COS) and carbon disulfide (CS_2). Both HAP components are by-products of reactions in SRU reactors. COS may also result from incomplete combustion from a thermal oxidizer.

Compliance Costs

There are 164 U.S. petroleum refineries included in this analysis. Of these, 127 refineries will be affected in that they are expected to incur compliance costs as a result of the implementation of the proposed NESHAP.

Table ES-1 provides a summary of estimated compliance costs.[2] Compliance costs include the costs of purchasing and installing emission control equipment, annual operating and maintenance costs, and monitoring and record-keeping costs. Affected refineries are expected to incur average (per-refinery) capital costs of $1.42 million, average annual operating, maintenance, monitoring and record-keeping costs of about $280 thousand, and average annualized costs of about $420 thousand. Estimated industry-wide capital cost total about $181.32 million while annualized costs total about $53.52 million.

[2] See Appendix C for refinery-specific estimates of compliance costs.

Table ES-1

SUMMARY OF ESTIMATED COMPLIANCE COSTS
($ 1996 million)

	Capital Costs	Annual Operating and Maintenance Costs	Annualized Costs[a]
Average Cost per Affected Refinery[b]	1.42	0.28	0.42
Industry Total Costs	181.32	35.54	53.52

Note: [a] Capital costs annualized at a 7 percent discount rate.
[b] Industry total costs averaged over 127 refineries expected to incur compliance costs.

Source: Computed from data in EPA (1997b).

SUMMARY OF ESTIMATED IMPACTS

Primary and Secondary Impacts

Table ES-2 summarizes the estimates of the primary and secondary economic impacts associated with the proposed NESHAP. Primary impacts include price increases, reductions in market output levels, changes in the value of shipments by domestic producers, and plant closures. Secondary impacts include employment losses, reduced energy use, changes in net exports, and potential regional impacts. We emphasize that the assumptions adopted in our analysis are likely to cause us to overstate the adverse primary and secondary impacts of the proposed NESHAP.[3]

Table ES-2

SUMMARY OF ESTIMATED ECONOMIC IMPACTS

Analysis	Estimated Impacts
Primary Impacts	
Price Increases	Estimated price increase of refined petroleum products of 0.24 percent.
Domestic Output	Estimated reduction in domestic output of 0.17 percent.
Value of Domestic Shipments	Increase in the value of domestic shipments of 0.07 percent.
Plant Closures	No plant closures predicted under worst-case assumption.
Secondary Impacts	
Employment	Employment losses of 0.19 percent (136 jobs).
Energy Use	Estimated industry-wide energy use to decline by 0.18 percent.
Net Exports	Net exports decline an estimated 0.76 percent.
Regional Impacts	No significant regional impacts are expected.

We estimate that the market prices of refined petroleum products will increase by about 0.24 percent and production at domestic refineries will decline by about 0.17 percent. The decline in domestic production is due to higher imports and reduced quantity demanded because of higher prices. Note, however, that we expect an *increase* in the value of shipments by

[3] For example, we assume that plants with the highest compliance costs are the least efficient producers in the market. Also, our analysis does not consider that some plants are protected by regional trade barriers. Actual plant closures will be fewer than predicted closures if plants with high compliance costs are not the least efficient producers or if these plants are protected by regional trade barriers.

domestic refineries. This occurs because the estimated price increase more than offsets the lower production volume.

Our analysis predicts that no refineries are at risk of closure under the proposed NESHAP.

The estimates of secondary impacts reported in Table ES-2 are consistent with the primary impacts estimates described above. We note that these estimates are also affected by the worst-case assumptions in our analysis, and accordingly, are likely to be overstated.

Financial Analysis

Our analysis of financial data for a sample of firms indicates that capital and annual compliance control costs are small relative to the financial resources of firms operating petroleum refineries. As a result, we do not find evidence that it will be difficult for these firms to raise the capital required to purchase and install emission controls. We note, however, that the producers for which financial data are available tend to be larger publicly held companies. These firms might not be representative of all producers in the industry.

Sensitivity Analyses

Appendix A examines the sensitivity of the estimated primary impacts to alternative assumptions about market demand and supply elasticities. The results reported there indicate that the primary impacts summarized in Table ES-2 are relatively insensitive to reasonable ranges of elasticities.

Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 (RFA), as amended by the Small Business Regulatory Enforcement Act of 1996 (SBREFA), requires EPA to determine whether proposed regulations will have a significant economic impact on a substantial number of small entities (SISNOSE). Small entities include small businesses, small governments and small organizations (e.g., non-profit organizations). The Small Business Administration (SBA) defines businesses by Standard Industrial Classification (SIC) codes and typically defines business sizes by measures such as employment or sales. SBA classifies petroleum refineries as small if corporate-wide employment is less than 1,500 *and* daily crude processing capacity is less than 75,000 b/cd.

Annualized compliance costs are less than one percent of estimated sales revenues for all small businesses included in this analysis. Only two small businesses are expected to be affected by the selected regulatory alternatives. Based on EPA's interim guidance for complying with SBREFA, we classify the proposed NESHAP as "Category 1." EPA's interim guidance states that a Category 1 rule is presumed **not** to have a significant economic impact on a substantial number of small entities. We caveat that our analysis is subject to the limitations noted in Section 6 of this report.

Social Costs of the Proposed NESHAP

We estimate that the proposed NESHAP will cause the economy to incur social (economic) costs of about $63.31 million annually.[4] We measure social costs as the change in economic surplus resulting from compliance costs. Estimated annual social costs are higher than estimated annualized compliance costs because the former include the surplus losses to the U.S. economy because of higher imports.

[4] Our estimate of social costs is also likely to be overstated because of worst-case assumptions adopted in our analysis.

LIMITATIONS

Several limitations of the analyses used to estimate the impacts of the alternative NESHAPs are described throughout this report. All of these limitations should be considered in interpreting the estimated impacts summarized above. In particular, many of the assumptions adopted in the analyses tend to cause the estimated adverse impacts associated with the proposed NESHAP to be overstated.

ORGANIZATION OF REPORT

Section 1 of this report is a profile of the petroleum refining industry. In Section 2, we describe HAP emission sources and summarize compliance costs. We describe the analytical methods employed to estimate the economic impacts associated with the proposed NESHAP in Section 3. In Section 4, we report estimates of primary economic impacts, including those on market prices, market output levels, value of shipments by domestic producers, and plant closures. Section 4 also includes an analysis of the effects of the NESHAP on affected firms' financial ratios. Section 5 presents estimates of secondary impacts, including the effects on employment, foreign trade, energy use and regional economies. We describe the regulatory flexibility analysis in Section 6. In Section 7, we report estimates of the social costs of the proposed NESHAP.

There are four appendices to this report. We describe the results of sensitivity analyses in which we consider ranges of demand and supply elasticities in Appendix A. Appendix B provides a detailed technical description of the analytical methods employed to estimate economic impacts and costs. Appendix C lists the refineries included in the analyses and presents estimates of compliance costs. In Appendix D, we report the results of a financial sensitivity analysis.

CHAPTER 1

INDUSTRY PROFILE

INTRODUCTION

This section is a profile of the petroleum refining industry. First, we describe the current structure of the refining industry. Next, we summarize information on production, supply, demand, pricing, foreign trade, and other industry characteristics. We also present industry trends and the market outlook for refined petroleum products. Finally, we describe the characteristics of small businesses operating in the industry.

Currently about 90 firms operate more than 160 petroleum refineries in the U.S.[1] The combined estimated crude processing capacity of these refineries is approximately 15.4 million barrels per calendar day (b/cd). Three states, California, Louisiana and Texas dominate the domestic petroleum refining industry. Together, 60 refineries in these three states account for about 46 percent of domestic crude capacity. Also, the corporate headquarters of many firms operating refineries are located in these three states.

INDUSTRY STRUCTURE

The petroleum industry can be divided into five distinct sectors: exploration, production, refining, transportation, and marketing. Below we review the products and processes of the refining sector of the industry and presents a basic refining industry profile that includes employment and geographical distribution.

Products and Processes

Crude oil — unprocessed oil obtained directly from the ground — has limited uses. It is the refining process that transforms crude oil into numerous different petroleum products which have a variety of applications. Most petroleum refinery output consists of motor gasoline and

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[1] A survey published in the Oil & Gas Journal (1996) lists 163 refineries operating as of January 1, 1997. In addition, there are a few operating refineries not listed in the survey.

other types of fuel, but some non-fuel uses exist, such as petrochemical feedstocks, waxes, and lubricants. The output of each refinery is a function of its crude oil feedstock and its preferred petroleum product slate. Table 1-1 gives an overview by Petroleum Administration for Defense Districts (PADDs), of the various refined petroleum products produced in the United States.[2]

There are numerous refinery processes from which emissions occur. *Separation processes* (such as atmospheric distillation and vacuum distillation), *breakdown processes* (thermal cracking, coking, visbreaking), *change processes* (catalytic reforming, isomerization), and *buildup processes* (alkylation and polymerization) all have the potential to emit HAPs. HAP emissions may occur through process vents, equipment leaks, or from evaporation from storage tanks or wastewater streams.

U.S. Refinery Characteristics

It is important to note the distinction between refineries and firms. A *refinery* is an individual establishment or facility that processes crude oil, while a *firm* is a corporate entity that owns or operates several refineries. There are currently about 163 operable petroleum refineries in the United States, controlled by about 90 firms. (DOE, Energy Information Administration, 1994). Though refineries differ in capacity and complexity, almost all refineries have some atmospheric distillation capacity and additional downstream charge capacity, such as the processes described above. The Standard Industrial Classification (SIC) code for all petroleum refineries is 2911.

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[2] The U.S. petroleum market is segmented into five regions called PADDs. These were established in the 1940s for the purpose of dividing the country into economically and geographically distinct regions. Much of the U.S. petroleum data is maintained by PADD.

Table 1-1

1995 PETROLEUM PRODUCT NET PRODUCTION
(1,000 barrels)

	PADD						
Product	I	II	III	IV	V	Total U.S.	Percent of Total
Motor Gasoline	310,554	647,944	1,214,003	88,511	461,391	2,722,403	46.63
Distillate Fuel Oil	151,155	280,817	510,061	47,212	162,490	1,151,735	19.73
Jet Fuels	31,487	71,143	257,697	10,548	145,884	516,759	8.85
Residual Fuel Oil	56,121	22,394	123,782	3,714	81,590	287,601	4.93
Liquefied Refinery Gases	17,330	47,412	141,608	2,586	29,846	238,782	4.09
Still Gas	22,404	47,408	108,894	7,540	49,996	236,242	4.05
Petroleum Coke	17,849	47,498	105,698	5,078	53,832	229,955	3.94
Asphalt and Road Oil	31,375	66,818	41,666	12,683	17,852	170,394	2.92
Other Oils for Petrochemical Feedstock Use	90	8,419	76,445	244	3,462	88,660	1.52
Lubricants	6,279	8,238	39,654	0	9,519	63,690	1.09
Naphtha for Petrochem Feedstock Use	2,250	8,448	50,216	0	1,856	62,770	1.08
Kerosene	1,960	8,121	7,354	786	961	19,182	0.33
Special Naphthas	848	4,352	12,416	0	597	18,213	0.31
Miscellaneous Products	609	3,774	8,615	1,165	1,847	16,010	0.27
Aviation Gasoline	80	1,116	4,527	184	1,929	7,836	0.13
Waxes	1,679	886	4,249	70	829	7,713	0.13

Source: Petroleum Supply Annual 1995, Volume 1, Table 17.

Refinery Capacity and Complexity

An economic impact analysis requires that plants in the industry be identified and classified by some production factor or other descriptive, quantifiable characteristic. This can be difficult in the case of petroleum refineries, because refineries have many different specialties, targeted product slates, and capabilities. Some refineries produce output only by processing crude oil through basic atmospheric distillation and have very little ability to alter their mix of product yields. These refineries are said to have low complexity. In contrast, refineries which have assorted downstream processing units can substantially vary their mix of product yields and have a higher level of complexity. Because of their different sizes and complexities, refineries can be grouped by two main structural features: (1) atmospheric distillation capacity (which denotes their size) and (2) process complexity (which characterizes the type of products a refinery is capable of producing).

Capacity is a characteristic often used to categorize petroleum refineries in market analyses. (A detailed discussion of market characteristics, based on distillation capacity, will be presented in Section 4). Capacity may refer either to the number of barrels produced per *calendar* day, or to the number of barrels produced per *stream* day. Barrels per stream day denotes the amount that a unit can process while running at full capacity, under optimal crude oil and product slate conditions. Barrels per calendar day represents the maximum amount that is processed in a 24-hour period, after making allowances for downtime and other limitations. Barrels per calendar day is always less than or equal to barrels per stream day. Throughout this report, barrels per calendar day and barrels per stream day will be referred to as “barrels per day” (bbl/d). Any bbl/d data that is presented in a table will reflect consistent measurement within that table; barrel per calendar day data will not be compared to barrel per stream day data.

National refining production capacity as of January 1, 1997 is summarized by PADD and by state in Table 1-2.[3] Figure 1-1 shows the geographic breakdown for each PADD. Several industry trends are evident from the PADD-level totals in Table 1-1. First, PADD III has more than twice the capacity of any other single PADD, mainly because much of the domestic crude

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[3] Mathtech (1997), Appendix A provides the production capacity for all firms and refineries in the petroleum refining industry.

oil supply is located in this region. Conversely, PADDs I and IV have relatively little capacity. The availability of petroleum products in each PADD plays a role in the import/export characteristics of each region.

The geographical distribution of refining capacity is important for several reasons. Regional markets may differ due to the quality of crude supplied and regional product demand. In addition, because refineries are the source of non-hydrocarbon pollutants such as individual HAPs, volatile organic compounds (VOCs), sulfur dioxide (SO_2), and nitrogen oxide (NO_x), many Federal, State, and local regulations are already in place in some locations. Differences in the regional market structure may also result in different import/export characteristics.

Table 1-3 shows the distribution of atmospheric distillation operating capacity among the 90 firms in the industry. This table divides firms into three groups of 23 and a fourth group of 21 firms each according to atmospheric distillation capacity. The top quarter, which contains the 23 firms with highest operation capacity, constitutes 79.7 percent of the total national capacity, with an average capacity of 534,519 bbl/d. As a group, the remaining 67 firms (the lower three-quarters of the industry) produce 20.3 percent of the total national operating capacity. Additional analysis of market concentration will be presented in the next section of this report.

Table 1-2

PRODUCTION CAPACITY OF
OPERABLE PETROLEUM REFINERIES (JANUARY 1, 1997)

	No of Refineries	Atmospheric Crude Distillation (b/cd)	Vacuum Distillation (b/cd)	Coking (b/cd)	Thermal Operations (b/vd)	Catalytic Cracking (b/cd)	Catalytic Reforming (b/cd)	Catalytic Hydrocracking (b/cd)	Catalytic Hydrorefining (b/cd)	Catalytic Hydrotreating (b/cd)
PAD District I Totals	17	1,489,600	613,175	82,450	10,000	493,900	306,888	51,400	105,000	558,660
Delaware	1	140,000	85,500	41,850	0	63,000	45,900	17,100	0	122,760
Georgia	2	34,000	0	0	0	0	0	0	0	0
New Jersey	6	674,000	268,900	22,600	10,000	282,700	118,400	0	105,000	104,480
Pennsylvania	6	574,400	221,775	0	0	122,500	128,488	30,000	0	298,720
Virginia	1	56,700	32,300	18,000	0	25,700	10,800	0	0	28,900
West Virginia	1	10,500	4,700	0	0	0	3,300	4,300	0	3,800
PAD District II Totals	31	3,431,540	1,369,275	376,260	9,074	1,178,030	912,630	146,900	283,720	2,051,600
Illinois	6	909,550	362,100	106,110	5,000	322,200	336,920	58,000	0	576,820
Indiana	3	435,990	235,200	30,400	0	157,050	92,000	0	89,300	208,900
Kansas	3	283,350	112,310	52,600	0	79,120	60,470	9,400	39,600	182,480
Kentucky	2	224,800	89,240	53,350	4,074	97,000	43,195	0	39,200	172,505
Michigan	3	121,200	37,000	0	0	45,500	27,900	0	0	87,700
Minnesota	2	355,000	191,040	66,000	0	108,810	75,795	0	22,310	345,700
North Dakota	1	58,000	0	0	0	24,700	11,500	0	0	16,800
Ohio	4	499,650	162,710	37,800	0	173,550	153,200	75,000	62,810	173,895
Oklahoma	5	403,000	160,175	30,000	0	109,700	88,050	4,500	25,000	217,300
Tennessee	1	105,000	0	0	0	50,000	16,000	0	0	61,000
Wisconsin	1	36,000	19,500	0	0	10,400	7,600	0	5,500	8,500
PAD District III Totals	60	7,070,715	3,264,885	788,100	42,800	2,588,631	1,731,380	693,720	882,700	4,138,510
Alabama	3	134,225	47,550	10,800	0	0	26,480	0	26,800	73,310
Arkansas	3	65,200	25,500	0	0	19,100	12,400	0	21,000	34,800
Louisiana	19	2,417,290	1,098,385	328,900	22,200	885,900	463,200	185,100	145,500	1,115,590
Mississippi	4	336,800	257,050	71,000	0	63,000	71,000	58,000	84,000	146,500
New Mexico	3	97,600	19,000	0	0	32,331	31,800	0	26,500	37,800
Texas	28	4,019,600	1,817,400	377,400	20,600	1,588,300	1,126,500	450,620	578,900	2,730,510
PAD District IV Totals	15	515,675	225,920	35,200	0	172,600	111,025	4,500	57,950	306,225
Colorado	2	85,500	29,500	0	0	27,000	19,000	0	0	42,500
Montana	4	143,850	94,175	19,000	0	53,000	31,500	4,500	34,000	131,300
Utah	5	159,500	41,100	7,200	0	43,400	31,400	0	0	66,600
Wyoming	4	126,825	61,145	9,000	0	49,200	29,125	0	23,950	65,825
PAD District V Totals	40	2,925,065	1,467,050	566,870	23,000	746,970	579,560	453,970	374,960	1,488,310
Alaska	6	283,000	22,500	27,000	0	0	12,000	9,000	0	12,000
California	23	1,898,815	1,084,550	466,820	10,000	608,470	428,260	376,970	354,960	1,204,110
Hawaii	2	149,000	70,000	0	13,000	21,000	13,000	18,000	0	3,000

	No of Refineries	Atmospheric Crude Distillation (b/cd)	Vacuum Distillation (b/cd)	Coking (b/cd)	Thermal Operations (b/vd)	Catalytic Cracking (b/cd)	Catalytic Reforming (b/cd)	Catalytic Hydrocracking (b/cd)	Catalytic Hydrorefining (b/cd)	Catalytic Hydrotreating (b/cd)
PAD District I Totals	17	1,489,600	613,175	82,450	10,000	493,900	306,888	51,400	105,000	558,660
Delaware	1	140,000	85,500	41,850	0	63,000	45,900	17,100	0	122,760
Georgia	2	34,000	0	0	0	0	0	0	0	0
New Jersey	6	674,000	268,900	22,600	10,000	282,700	118,400	0	105,000	104,480
Pennsylvania	6	574,400	221,775	0	0	122,500	128,488	30,000	0	298,720
Virginia	1	56,700	32,300	18,000	0	25,700	10,800	0	0	28,900
West Virginia	1	10,500	4,700	0	0	0	3,300	4,300	0	3,800
PAD District II Totals	31	3,431,540	1,369,275	376,260	9,074	1,178,030	912,630	146,900	283,720	2,051,600
Illinois	6	909,550	362,100	106,110	5,000	322,200	336,920	58,000	0	576,820
Indiana	3	435,990	235,200	30,400	0	157,050	92,000	0	89,300	208,900
Kansas	3	283,350	112,310	52,600	0	79,120	60,470	9,400	39,600	182,480
Kentucky	2	224,800	89,240	53,350	4,074	97,000	43,195	0	39,200	172,505
Michigan	3	121,200	37,000	0	0	45,500	27,900	0	0	87,700
Minnesota	2	355,000	191,040	66,000	0	108,810	75,795	0	22,310	345,700
North Dakota	1	58,000	0	0	0	24,700	11,500	0	0	16,800
Ohio	4	499,650	162,710	37,800	0	173,550	153,200	75,000	62,810	173,895
Oklahoma	5	403,000	160,175	30,000	0	109,700	88,050	4,500	25,000	217,300
Tennessee	1	105,000	0	0	0	50,000	16,000	0	0	61,000
Wisconsin	1	36,000	19,500	0	0	10,400	7,600	0	5,500	8,500
PAD District III Totals	60	7,070,715	3,264,885	788,100	42,800	2,588,631	1,731,380	693,720	882,700	4,138,510
Alabama	3	134,225	47,550	10,800	0	0	26,480	0	26,800	73,310
Arkansas	3	65,200	25,500	0	0	19,100	12,400	0	21,000	34,800
Louisiana	19	2,417,290	1,098,385	328,900	22,200	885,900	463,200	185,100	145,500	1,115,590
Mississippi	4	336,800	257,050	71,000	0	63,000	71,000	58,000	84,000	146,500
New Mexico	3	97,600	19,000	0	0	32,331	31,800	0	26,500	37,800
Texas	28	4,019,600	1,817,400	377,400	20,600	1,588,300	1,126,500	450,620	578,900	2,730,510
Nevada	1	7,000	6,000	0	0	0	0	0	0	0
Oregon	1	0	15,000	0	0	0	0	0	0	0
Washington	7	587,250	269,000	73,050	0	117,500	126,300	50,000	20,000	269,200
U.S. Total	163	15,432,595	6,940,305	1,848,880	84,874	5,180,131	3,641,483	1,350,490	1,704,330	8,543,305

Source: Oil & Gas Journal (1996).

Figure 1-1

PETROLEUM ADMINISTRATION FOR DEFENSE (PAD) DISTRICTS

Table 1-3

NATIONAL DISTRIBUTION BY ATMOSPHERIC DISTILLATION CAPACITY

	Number of Firms	Average Atmospheric Distillation Operating Capacity (bbl/d)	Total Operating Capacity (bbl/d)	Percentage of National Total
	23	534,519	12,293,935	79.7
	23	104,006	2,392,145	15.5
	23	26,263	604,050	3.9
	21	6,784	142,465	0.9
Total	90	171,473	15,432,595	100.0

Source: Oil & Gas Journal (1996).

Complexity is a measure of the different processes used in refineries. It can be quantified by relating the complexity of a downstream process with atmospheric distillation, where atmospheric distillation is assigned the lowest value, 1.0. Table 1-4 lists the processes and corresponding capacity factors used in this analysis. The complexity factors are arranged by four types of refining processes. The level of complexity of a refinery generally correlates to the types of products the refinery is capable of producing. Higher complexity denotes a greater ability to diversify product output, to improve yields of preferred products, or to process lower quality crude. By defining refinery complexity, it is possible to differentiate among refineries having similar capacities but different process capabilities. In theory, more complex refineries are more adaptable to change, and are potentially less affected by regulation.

Tables 1-5 and 1-6 summarize the refinery complexity distribution for U.S. refineries as of January 1, 1997. To arrive at a value for complexity, a listing is made of all processing units, along with the capacity and complexity factor for each process. The contribution of each process to the total processing capacity is calculated by multiplying the complexity factor by the ratio of its process capacity to total atmospheric distillation capacity.

Table 1-4

COMPLEXITY FACTORS

Refinery Processes by Process Type	Complexity Factor
Separation Processes	
Atmospheric distillation	1.0
Vacuum distillation	2.0
Breakdown Processes	
Thermal cracking	3.0
Coking	5.5
Catalytic cracking	6.0
Hydrocracking	10.0
Change Processes	
Isomerization	3.0
Catalytic reforming	5.0
Buildup Processes	
Alkalization	11.0
Supporting Operations (Other)	
Catalytic hydrotreating	2.0
Hydrodesulfurization	7.0
Aeromatics	33.0
Lube oil manufacturing	44.0

Source: The Pace Company. Oil Industry Forecast (1982).

Table 1-5

1997 REFINERY COMPLEXITY DISTRIBUTION:
NUMBER OF REFINERIES

	Size Range (1,000 barrels per day)						
Complexity Range	0-10	10-30	30-50	50-100	100-175	175+	Total
Under 3	16	8	3	1	1	0	29
3-5	3	2	2	4	0	0	11
5-7	1	6	3	6	2	1	19
7-9	0	4	6	14	8	7	39
9-11	1	0	3	5	4	12	25
Over 11	5	7	0	7	11	10	40
Total refineries	26	27	17	37	26	30	163

Source: Oil & Gas Journal (1996) and the Pace Company (1982).

The following example illustrates how refinery complexity helps to differentiate between plants and explains the method used to derive complexity. Assume there are two refineries that must be compared. Both have a 100,000 bbl/d atmospheric distillation capacity. One has no downstream charge capacity, while the other has a downstream capacity of 15,000 bbl/d for thermal cracking and 30,000 bbl/d for catalytic reforming. An economic analysis that solely examines atmospheric distillation capacity would not distinguish between the two. However, an analysis that accounts for complexity would note the fundamental difference between the product slate of each.

The formula for complexity is:

$$\sum_{i=1}^{n} cf_i \left(\frac{Process_i \ Capacity}{Atmospheric \ Distillation \ Capacity} \right)$$

where: cf_i = the complexity factor from Table 1-4

$Process_i$ = the appropriate downstream process capacity

Table 1-6

1997 REFINERY COMPLEXITY DISTRIBUTION: OPERABLE CAPACITY

	Size Range (thousand barrels per day)							
Complexity Range	0-10	10-30	30-50	50-100	100-175	175+	Total Capacity	Percentage of Total
Under 3	89,930	146,000	124,800	80,000	130,000	0	570,730	3.7
3-5	18,800	29,300	83,000	323,000	0	0	454,100	2.9
5-7	0	116,875	127,225	377,100	240,850	240,000	1,102,050	7.1
7-9	0	94,800	266,000	913,060	1,101,950	1,578,000	3,953,810	25.6
9-11	6,000	0	141,600	412,350	544,995	3,163,300	4,268,245	27.7
Over 11	37,185	139,300	0	544,275	1,492,350	2,870,550	5,083,660	32.9
Total Refineries	151,915	526,275	742,625	2,649,785	3,510,145	7,851,850	15,432,595	100.0

Source: Calculated from Oil & Gas Journal (1996) and The Pace Company (1982).

Since the refinery with no downstream charge capacity is only capable of atmospheric distillation, its complexity by definition is 1.0. The second refinery's complexity is calculated using the formula from above as follows:

$$Complexity = 1 + 3\left(\frac{15{,}000}{100{,}000}\right) + 5\left(\frac{30{,}000}{100{,}000}\right) = 2.95$$

Although neither refinery can be considered extremely complex, the second refinery, by virtue of its downstream cracking and reforming capabilities, has greater ability to alter its yield.

As Table 1-5 indicates, the complexity of a refinery usually increases as its crude capacity increases (lube plants are the exception to this rule). As Table 1-6 indicates, over 86 percent of the operable capacity can be found at refineries with above-average complexity (above 7.0).

Market Concentration

Market concentration can be measured as the output of the largest firms in the industry, expressed as a percentage of total national output. Market concentration is usually measured for the 4, 8, or 20 largest firms in the industry. For example, at one extreme, a concentration of 100 percent would indicate monopoly control of the industry by one firm. Alternatively, a concentration of less than 1 percent would indicate the industry was comprised of numerous small firms.

The American Petroleum Institute (API) has compiled a time-series set of market concentration data for the petroleum refining industry (API, 1990). Concentration is measured based on refining capacity which is based on information developed from “Petroleum Supply Annual” data on operable refining capacity per calendar day (DOE, 1995a). Table 1-7 summarizes refinery concentration for selected years in the past decade. Until recently, the top four firms have consistently comprised over 30 percent of the market share, but most market concentration ratios have marginally decreased in recent years. As Table 1-7 indicates, the market concentration for the top four firms in 1995 has decreased to under 27 percent.

In addition to standard units of measure, API uses the Herfindahl-Hirschman index to gauge market concentration. The Herfindahl-Hirschman index is defined as the sum of the squared market shares (expressed as a percentage) for all firms in the industry. If a monopoly existed (one firm with a market share of 100 percent), the upper limit of the index (10,000) would be attained. If an infinite number of small firms existed, the index would equal zero. The last row of Table 1-7 reports the Herfindal-Hirschman index for the petroleum refining industry. Since 1988, this index has been less than 500, indicating a relatively unconcentrated industry.

Table 1-7

CONCENTRATION IN REFINING CAPACITY

	Percentage of Market Concentration						
Refinery Industry Concentration	1980	1985	1986	1987	1988	1989	1995*
4-firm	29.0	34.4	33.2	32.2	32.3	31.6	26.7
8-firm	49.0	54.4	53.0	52.0	53.3	50.0	43.8
15-firm	67.0	73.0	71.6	70.5	72.8	68.9	61.6
20-firm	74.5	80.3	79.0	77.2	80.4	77.9	70.5
30-firm	82.3	88.8	87.9	86.3	89.0	88.2	82.3
Herfindahl-Hirschman Index	381.5	494.6	471.2	448.2	465.4	431.9	338.2

NOTES: * Calculated independently from Oil & Gas Journal (1996).

Source: American Petroleum Institute.

Industry Integration and Diversification

Vertical and horizontal integration are measures of the control a firm has over the product and factor markets for its good or service. *Diversification* indicates the extent to which a firm has developed other revenue producing operations, in addition to petroleum refining.

Vertical Integration

Vertical integration exists when the same firm engages in several stages of the production and marketing process. Some firms that operate petroleum refineries are vertically integrated because they explore and produce crude oil (which supplies the input for refineries), and market finished petroleum products after refining. Firms that are vertically integrated could be indirectly affected by the NESHAP at several stages of production if the regulation results in reduced refinery throughput.

Major refineries are more likely to be *vertically integrated* than independents. A definition of major energy producers, *majors*, was originally developed by DOE's Energy Information Administration (EIA) in 1976. (DOE, 1991b). EIA requires all majors to provide financial information on Form EIA-28, which is incorporated into EIA's Financial Reporting System (FRS). Selection criteria for the original list of 27 publicly-owned majors included those firms which had either at least one percent of the production or the reserves of oil, gas, coal, or uranium, one percent of the refining capacity, or one percent of petroleum product sales. EIA's current list reflects mergers, acquisitions, and spinoffs from the original list. Table 1-8 lists 16 firms (with refining capacity) that are currently considered to be major energy producers. The table also shows the percentage of refining capacity operated by each of the firms. The crude capacity of the major, vertically integrated firms represents over 52 percent of nationwide production. Major firms in the petroleum industry are likely to be vertically integrated.

Table 1-8

MAJOR ENERGY FIRMS WITH REFINING CAPACITY
(January 1, 1997)

Company	Barrels per Calendar Day (Operating)	Percentage of National Total
Amerada Hess Corp.	0	0.0
Amoco Oil Co.	1,009,700	6.5
Ashland Oil Inc.	354,200	2.3
Chevron U.S.A. Inc.	1,047,000	6.8
Coastal	235,000	1.5
Conoco Inc.	437,900	3.2
Exxon Co. U.S.A.	1,017,000	6.6
Fina Oil & Chemical Co.	236,500	1.5
Marathon Oil Co.	531,000	3.4
Mobil Oil Corp.	979,100	6.3
Phillips 66 Co.	345,000	2.2
Shell Oil Co.	896,700	5.8
Sun Co. Inc.	210,000	1.4
Texaco Refining & Marketing Inc.	385,035	2.5
Total Petroleum Inc.	141,600	0.9
Unocal Corp.	222,395	1.4
Total	8,098,130	52.47

Source: Oil & Gas Journal (1996).

We caution that, by definition, major refineries need not be vertically integrated. However, majors tend to be larger than independents, and accordingly, are more likely to engage in greater degree of vertical integration. In short, we use the distinction between majors and independents as an indicator of *tendency* to vertically integrate.

Horizontal Integration

Horizontal integration exists when a firm owns or operates several establishments within the same stage of the production process. Some oil companies are horizontally integrated because they operate several refineries, often distributed across different regions of the country. Horizontally integrated firms may be affected by emission regulations differently depending on the existing regulations in different regions. For example, some of a firm's facilities may be located in nonattainment areas and may therefore already have substantial emission controls in place, while facilities in attainment areas may be less stringently controlled.

Figure 1-2 shows the horizontal integration of the industry, portrayed by the number of refineries operated by each firm. Note that 75 of the 90 firms in the industry operate only one refinery. Many of these are smaller independent firms that derive a substantial portion of their revenues from petroleum refining operations. Major firms generally operate several refineries, and the largest, Chevron, operates 9. Nine firms operate four or more refineries.

Diversification

Diversification, or *conglomeration*, exists when firms produce a variety of unrelated products. Large diversified firms might find it easier to raise capital to purchase and install emission control equipment than smaller undiversified firms. However, firms will not subsidize petroleum product production with profit from other operations, but will close unprofitable operations instead.

Refinery Industry Employment

Refinery industry employment data for 1997 are not currently available. The 1992 Census of Manufactures for petroleum and coal products lists the 1992 data for employment and number of establishments for SIC code 2911. (U.S. Department of Commerce, 1992 Census of Manufactures). The Census of Manufactures data are summarized in Table 1-9.

Figure 1-2

HORIZONTAL INTEGRATION IN THE PETROLEUM REFINING INDUSTRY

Source: Oil & Gas Journal (1996).

There is a discrepancy between the number of establishments reported in the Census of Manufactures for the petroleum refining industry and what DOE data reports. For 1992, the Census lists 232 establishments, while DOE includes 199. In Table 1-9, the number of establishments is adjusted by scaling the total number of refineries reported by DOE in 1992 by the percentage of establishments in each employment class reported in the Census of Manufactures.

According to the adjusted refinery data, approximately 4 percent of refinery employees work in plants of fewer than 100 people. The remaining 96 percent of the labor force in the industry work in establishments of 100 or more employees.

Table 1-9

EMPLOYMENT IN THE PETROLEUM REFINING INDUSTRY (1992)

Establishments with an average of:	All Establishments	Number of Refineries	Total Employees (-1,000)	Percent of Total
1 to 4 employees	17	15	z	7.33
5 to 9 employees	7	6	z	3.02
10 to 19 employees	11	9	0.2	4.74
20 to 49 employees	35	30	1.2	15.09
50 to 99 employees	22	19	1.7	9.48
100 to 249 employees	45	39	8.0	19.40
250 to 499 employees	49	42	16.9	21.12
500 to 999 employees	26	22	18.1	11.21
1,000 to 2,499 employees	20	17	28.9	8.62
All establishments	232	199	75.0	100.00

Notes: z less than 100.
Source: U.S. Census of Manufacturers, 1992.

MARKET CHARACTERISTICS

An economic impact analysis should consider the characteristics of markets in which petroleum products are traded. This section describes several market characteristics including product differentiation, availability of substitutes, and foreign trade. Also, this section describes the determinants of market supply and demand and discusses price elasticities.

Product Differentiation

Product differentiation is a form of non-price competition used by firms to target or protect a specific market. Firms can distinguish their product from those of competing firms by adjusting the quality of the product, by advertising to develop a brand name, or by providing additional goods or services along with a product.

The extent to which product differentiation is effective depends on the nature of the product. The more homogenous the overall industry output, the less effective differentiation by individual firms becomes. Petroleum products are by nature quite homogenous — there is little difference between premium gasoline produced at different refineries. This tends to limit the role that product differentiation plays in the market for refined petroleum products. How-ever, we do note that many major refineries spend considerable resources on product promotion through advertising focused on brand identification.

Foreign Trade

Foreign producers may gain a competitive advantage if they are able to produce without any regulation while domestic production becomes and more costly because of emission controls. Foreign trade in petroleum products is substantial, as the data in Table 1-10 show. For example, U.S. imports average 1,605 thousand barrels per day in 1995. Exports averaged 942 thousand barrels per day during this year.

Table 1-10

U.S. PETROLEUM PRODUCT IMPORTS AND EXPORTS
(Thousand barrels per day)

Year	Imports	Exports	Net Imports	Import/ Export Ratio
1981	1,599	367	1,232	4.4
1982	1,625	579	1,046	2.8
1983	1,722	575	1,147	3.0
1984	2,011	541	1,470	3.7
1985	1,866	577	1,289	3.2
1986	2,045	631	1,414	3.2
1987	2,004	613	1,391	3.3
1988	2,295	661	1,634	3.5
1989	2,217	717	1,500	3.1
1990	2,123	748	1,375	2.8
1991	1,845	880	965	2.1
1992	1,805	861	944	2.1
1993	1,833	1,006	827	1.8
1994	1,933	942	991	2.1
1995	1,605	942	949	1.7

Source: Petroleum Supply Annual 1995, Volume 1.

Table 1-11 shows the different levels of foreign trade in each PADD in 1995. PADD I is by far the region with the largest net imports — its imports, 328,947 thousand barrels, exceeded its exports of 13,481 thousand barrels. Conversely, PADD V was a net exporter of products during 1995.

Table 1-11

1995 IMPORTS AND EXPORTS OF PETROLEUM PRODUCTS BY PADD
(Thousand barrels)

PADD	Imports	Exports	Net Imports
I	328,947	13,481	315,466
II	30,055	10,104	19,951
III	194,700	185,738	8,962
IV	6,881	157	6,724
V	4,621	102,487	(97,866)
U.S. Total	565,204	296,908	253,237

Source: Petroleum Supply Annual, 1995, Volume 1.

Some measure of the extent of foreign competition can be obtained by comparing imports or exports against domestic consumption or production. Table 1-12 shows the percentage of imports that constitutes domestic consumption and the percentage of exports that constitutes domestic production. For example, in 1995, imports represented about 9.1 percent of domestic consumption. During the same year, U.S. producers exported about 5.3 percent of their output.

Supply Determinants

In the short run, refineries face fixed capacity levels. They must then decide how much crude oil to allocate for the production of each of the refinery's products ranging from gasoline to jet and tanker fuel, kerosene, and asphalt. If the refinery is a profit maximizer, it will allocate crude across its product slate such that total refinery profit is maximized. If the refinery has perfect flexibility in adjusting its product slate, it will allocate a given amount of crude oil among its products such that the incremental profit each on the last barrel of each product is the same. Otherwise, the refinery could increase total profits by allocating less

Table 1-12

DEPENDENCY ON FOREIGN TRADE
(Million barrels per day)

Year	Imports	Domestic Petroleum Product Consumption	Exports	Domestic Refinery Output
1981	1.60	16.06	0.37	13.99
1982	1.63	15.30	0.58	13.39
1983	1.72	15.23	0.58	13.14
1984	2.01	15.73	0.54	13.68
1985	1.87	15.73	0.58	13.75
1986	2.05	16.28	0.63	14.52
1987	2.00	16.67	0.61	14.63
1988	2.30	17.28	0.66	15.02
1989	2.22	17.33	0.72	15.17
1990	2.12	17.33	0.75	15.26
1991	1.85	16.70	0.88	15.20
1992	1.81	17.03	0.86	15.30
1993	1.83	17.24	0.90	15.25
1994	1.93	17.72	0.84	15.26
1995	1.61	17.73	0.86	15.99

Source: Petroleum Supply Annual 1995, Volume 1.

crude to less incrementally profitable products and more crude to more incrementally profitable products. Furthermore, the optimal level of total crude used by the refinery will drive incremental profits to zero for each product. If this were not the case, the refinery could either increase or decrease its total use of crude and increase profits.

In practice, technological constraints limit the flexibility refineries have in adjusting their product slates. Nonetheless, the hypothetical case described above identifies the determinants of short-run supply. Specifically, the quantity of a given product (e.g., gasoline) that a refinery will supply at a given price (i.e., the price of gasoline) depends on the marginal cost of that product (i.e., the marginal cost of producing a barrel of gasoline) as well as the prices and marginal costs of all other products included in the refinery's slate.

In the long run, refineries have time to change capacity. They will increase capacity if expected future prices are sufficient to cover the cost of additional capacity as well as variable operating and maintenance costs. Accordingly, the long-run supply of refined products also depends on the incremental costs of expanding capacity. To the extent that the NESHAP increases the production costs of refined products, the decision to expand production capacity will depend on whether refineries can expect future prices to rise sufficiently to cover these additional costs associated with emission controls.

Refinery yields across product slates differ by region. As Table 1-13 shows, a percentage difference of 10 percent between PADDs is not uncommon. For example, the average yield of jet fuel in PADD V is over 16 percent, or 6 percent greater than any other PADD. PADD V seems to have the most unique product slate, with relatively little distillate fuel oil yield, and relatively high yields of residual fuel, jet fuels, petroleum coke and still gas. These regional differences in refinery yield are attributable to several factors, including local crude oil characteristics and regional petroleum product demand.

Capacity utilization rates of petroleum refineries have been rising in recent years, to a high of 92.6 percent in 1994 (DOE, 1994). This indicates that existing refineries are operating closer to full capacity, and will have less freedom to increase production by using existing capacity more intensively. If capacity utilization rates were low, domestic refineries could presumably increase utilization to increase the available supply. However, if utilization rates are high, then this option is not available, and further petroleum product supply will either need to be imported or new domestic refineries will have to be built. Table 1-14 shows operable capacity and capacity utilization by PADD since 1985. Note that operable capacity has remained relatively constant, while capacity utilization has risen steadily.

Table 1-13

REFINERY YIELDS BY PADD, 1995

	PADDs (percentage of total yield)				
Products	I	II	III	IV	V
Liquefied Refinery Gases	3.0	4.1	5.8	1.5	3.3
Finished Motor Gasoline	45.6	51.5	44.9	48.4	44.0
Finished Aviation Gasoline	0.2	0.1	0.2	0.1	0.2
Naphtha-Type Jet Fuel	0.0	0.0	0.0	1.5	0.0
Kerosene-Type Jet Fuel	5.4	6.1	10.5	4.8	16.1
Kerosene	0.3	0.7	0.3	0.5	0.1
Distillate Fuel Oil	25.9	24.0	20.7	28.2	17.9
Residual Fuel Oil	9.6	1.9	5.0	2.2	9.0
Naphtha for Petrochemical Feedstock Use	0.4	0.7	2.0	0.0	0.2
Other Oils for Petrochemical Feedstock Use	0.0	0.7	3.1	0.1	0.4
Special Naphthas	0.1	0.4	0.5	0.0	0.1
Lubricants	1.1	0.7	1.6	0.0	1.0
Waxes	0.3	0.1	0.2	0.0	0.1
Petroleum Coke	3.1	4.1	4.3	3.0	5.9
Asphalt and Road Oil	5.4	5.7	1.7	7.6	2.0
Still Gas	3.8	4.1	4.4	4.5	5.5
Miscellaneous Products	0.1	0.3	0.4	0.7	0.2
Processing Gain (-) or Loss (+)	−4.3	−5.1	−5.6	−3.4	−6.1

Source: Petroleum Supply Annual 1995, Volume 1.

Existing Federal, State and local regulations can affect the supply of petroleum products. Some refineries that are already regulated may have previously altered their production rates. The promulgation of a NESHAP may have additional effects upon supply however, so the burden placed on individual refineries as a result of regulations will vary. Those establishments already in ozone, carbon monoxide (CO), or particulate matter (PM_{10}) nonattainment areas may be only marginally effected by the NESHAP, due to the efficiency of existing controls. Conversely, existing controls cause these establishments to be operating at marginal profit levels, additional costs caused by the NESHAP could be especially burdensome.

Table 1-14

AVERAGE ANNUAL OPERABLE AND CAPACITY UTILIZATION RATES

Year/Element	PADD District I	II	III	IV	V	Total U.S.
1985						
Op. Capacity	1,538	3,367	7,199	558	3,010	15,671
% Utilization	75.4	81.5	77.2	77.6	75.6	77.6
1986						
Op. Capacity	1,456	3,296	7,106	534	3,065	15,459
% Utilization	84.3	85.9	83.5	81.0	78.2	82.9
1987						
Op. Capacity	1,450	3,282	7,174	535	3,202	15,642
% Utilization	86.6	86.9	82.5	81.7	79.1	83.1
1988						
Op. Capacity	1,464	3,302	7,449	537	3,176	15,927
% Utilization	88.5	88.7	81.8	84.7	84.2	84.4
1989						
Op. Capacity	1,452	3,267	7,377	552	3,054	15,701
% Utilization	87.2	89.2	84.2	83.4	88.4	86.3
1990						
Op. Capacity	1,505	3,307	7,165	555	3,091	15,624
% Utilization	83.5	92.0	85.6	83.4	87.9	87.1
1991						
Op. Capacity	1,492	3,338	7,235	551	3,092	15,707
% Utilization	81.3	92.3	83.7	83.9	87.1	86.0
1992						
Op. Capacity	1,520	3,379	7,136	510	2,914	15,460
% Utilization	81.5	92.7	86.0	86.4	90.6	87.9
1993						
Op. Capacity	1,541	3,381	6,789	518	2,914	15,143
% Utilization	88.0	95.0	92.1	87.4	88.5	91.5
1994						
Op. Capacity	1,526	3,324	6,905	508	2,886	15,150
% Utilization	89.3	97.8	92.5	91.1	89.0	92.6

Source: Petroleum Supply Annual 1995, 1994, 1993, 1992.

Although it is beyond the scope of this profile to review all State and local regulations, the following Federal regulations are important to note. There are four Control Technique Guidelines (CTG) documents which regulate VOC emissions from petroleum refinery sources.[4]

[4] EPA (1977a); EPA (1977b); EPA (1978a); EPA (1978b).

The CTGs call for reasonably available control technology (RACT) on all existing VOC sources within an ozone nonattainment area. Also, NO_x RACT rules will be instituted soon in ozone nonattainment areas and in the ozone transport region. Currently 90 refineries, or 55 percent of the domestic total, are located in ozone nonattainment areas.

Other Federal regulations exist which affect refineries. New Source Performance Standards (NSPSs) exist for several refinery source categories, including fuel gas combustion devices, claus sulfur recovery plants, and fluid catalytic cracking unit catalyst regenerators. There are also NSPSs for industrial boilers used in petroleum refineries. Thirty-seven refineries are located in CO nonattainment areas and others (not quantified) are in PM_{10} nonattainment areas. Other NESHAPs, such as the currently existing NESHAP for benzene, may already affect refineries.

It is possible that existing State or local regulations are more stringent than the proposed NESHAP. California's South Coast Air Quality Management District (SCAQMD) mandates control of reactive organic gases (ROG) from petroleum refinery flares and bulk terminals.[5] Based on California's past record of strict regulation (31 of the 32 refineries in California are in ozone nonattainment areas), it is possible that a NESHAP would impose very little additional cost on existing refineries in that State.

In a recent survey performed for DOE, refiners indicated that compliance with new regulations of air emissions is expected to be feasible, although the lack of coordination among different regulatory agencies may hinder companies in some regions (Cambridge Energy Research, 1992). Additionally, other requirements of the CAA may affect the refining industry. Title II requirements for the development of reformulated motor gasoline blends and oxygenated fuels are a specific concern.

Market Demand Determinants

[5] California South Coast Air Quality Management District. Final Air Quality Management Plan, 1991 Revision, Appendix IV-A, July 1991.

Generally, the demand for refined petroleum products is determined by price levels, economic growth trends, and weather conditions. Prices of refined petroleum products affect the willingness of consumers to choose petroleum over other fuels. Other things being the same, an increase in the price of a product reduces the quantity demanded on that product. For example, in the transportation sector, the effect of high gasoline prices on fuel use could reduce discretionary driving in the short term and, in the long term, result in the production of more fuel-efficient vehicles. Also, prices of substitutes affect the demand for petroleum; all else the same, higher prices of substitute goods increase the demand for refined products. Also, demand tends to grow with economic expansion and weather extremes.

Figure 1-3 shows a detailed breakdown of the 93.2 percent petroleum product demand attributed to fuel users for the years 1970 through 1990. Petroleum products used as transportation fuel include motor gasoline, distillate (diesel) fuel, and jet fuel. Together, these accounted for an estimated 64 percent of all U.S. petroleum demand in 1990. Since mobile source emissions will be regulated by Title II regulations, this is the output from petroleum refineries which will be most affected by the CAA. The industrial sector constitutes the second highest percentage of demand for petroleum products, followed by residential and electric utility demands.

Figure 1-3

PETROLEUM CONSUMPTION BY END-USE SECTOR

1-29

Source: U.S. Department of Energy, 1991a.

In the residential sector, demand for home heating is affected by weather and climate. Of course, regional temperature differences determine the degree to which buildings and houses are insulated. High prices for home heating oil provide incentive for individuals to conserve by adjusting thermostats, improving insulation, and by using energy-efficient appliances. In some cases, higher oil prices also provide incentive for switching to natural gas or electric heating. Adjusting thermostats is a short-run response, while changing to more energy-efficient appliances or fuels are long-run responses.

In the industrial sector, fuel oil competes with natural gas and coal for the boiler-feed market. High petroleum prices relative to other fuels tend to encourage fuel-switching, especially at electric utilities and in industrial plants having dual-fired boilers. Generally, in choosing a boiler for a new plant, management must choose between the higher capital/lower operating costs of a coal unit or the lower capital/higher operating costs of a gas-oil unit. In the utility sector, most new boilers in the early 1980s were coal-fired due to the impact of legislative action, favorable economic conditions, and long-term assured supplies of coal (Bonner and Moore, 1982). Today, because the CAA will require utilities to scrub or use a low-sulfur fuel, oil will eventually become more competitive with coal as a boiler fuel, although a significant increase in oil-fired capacity is not expected until 2010 (DOE, 1992).[6]

Periods of economic growth and periods of increased demand for petroleum products typically occur simultaneously. For example, in an expanding economy, more fuel is needed to transport new products, to operate new production capacity, and to heat new homes. Conversely, in periods of low economic growth, demand for petroleum products decreases. A decline in total petroleum product demand for the years 1989 to 1991, for example, is attributable in part to a slowdown in domestic economic activity and in part to moderate fuel efficiency gains (Hinton, 1992).

[6] The degree to which alternative fuel types are substitutes for refined petroleum products can be measured by cross-price elasticities. Unfortunately, we are not able to identify any estimates of these in the economic literature. However, the low estimates of own-price elasticities for refined products presented later in this section suggest that alternative fuels are poor substitutes for refined petroleum products.

The demand for most types of petroleum products, particularly in the residential sector, is affected by weather. As noted earlier, consumer demand for home heating oil is partly a function of the temperature and humidity levels. Weather extremes increase petroleum demand for heating and air-conditioning. In past years, petroleum refineries have realized reduced profits because mild winters have reduced residential fuel demand. Demand for transportation fuels is also determined by the weather, peaking in the summer months as vehicle miles traveled typically increase. However, the effects of weather conditions on the demand for petroleum products are typically cyclical and short-term.

The demand for petroleum products is also affected by international developments. For example, after the Iraqi invasion of Kuwait in August 1990, the demand for jet fuel increased as troops and supplies were transported from the United States to the Middle East. This increase in military demand was offset partially by reduced international air travel.

Elasticities of Supply and Demand

<u>Supply Elasticity</u>

As stated earlier in this section, prices of petroleum products affect the quantities supplied by the industry. There is a direct relationship between price and quantity supplied; as the price of a product falls, quantity supplied will decrease. To determine the extent to which suppliers will respond to increased compliance costs, one issue to be examined is the extent to which producers can "pass through" increased costs to consumers. The effect of emission control costs on product prices depends on the price elasticities of both supply and demand.

The degree to which quantity supplied is responsive to a change in price is measured by the price elasticity of supply. By definition, the price elasticity of supply is the percentage change in quantity supplied that results from a one percent increase in price. Supply becomes more elastic (i.e., more responsive to price changes) as the percentage change in quantity supplied increases. For a given demand curve, more elastic supply will result in a larger share of emission control costs being shifted to buyers through higher product prices. In the short run, supply elasticity is largely determined by the incremental costs of additional production. Short-run supply will be relatively elastic if incremental production costs rise slowly. This will more likely be the case when excess capacity exists in the industry. In the long run, supply elasticity is determined by the costs of additional capacity. Long-run supply will be relatively elastic if additional units of capacity result in just small increases in per barrel production costs.

One study by Pechan and Mathtech (1994) reports an estimated supply elasticity of 1.24 for refined petroleum products. This is an estimate of the supply elasticity for the entire product slate. We could not find any other estimates of supply elasticities in the economic literature.

Demand Elasticities

The degree to which emission control costs will lead to higher price levels for refined petroleum products depends upon the responsiveness of consumers to changes in price. Demand price elasticity is a measure of buyers' sensitivity to price changes. It is defined as the percentage change in the quantity of a good demanded per one percent change in price. Demand is more elastic (inelastic) the larger (smaller) the absolute percentage change in quantity demanded in response to a given percentage change in price.

Other things being the same, more inelastic demand results in a larger share of compliance costs being passed on to buyers in the form of higher prices. Also, other things being the same, a good that has few good substitutes will have more inelastic demand than a good for which many good substitutes are available.

Demand elasticities can be measured both in the short-run and the long-run. Demand tends to be more inelastic in the short run because buyers options for adjusting to higher prices are limited. Over time, however, demand tends to become more elastic as buyers have more time to adjust to price changes (e.g., by finding or developing substitutes). In short, the total response to a price change increases as the time allowed for behavioral adjustments increases.

We conducted a literature search of private firms, DOE/EIA, universities, and research laboratories to identify existing estimates of the price elasticities of demand for different refined petroleum products. We found numerous estimates of demand elasticities for motor gasoline, but relatively few for jet fuel and distillate oil. Lack of available data was the most common reason cited for this scarcity. Nonetheless, estimates of demand elasticities for gasoline, jet fuel, and residual and distillate fuel are available.

The main source of data is a 1981 study conducted by DOE which surveyed existing price elasticity analyses for gasoline and other petroleum products (DOE, 1981). The most comprehensive source of demand elasticities for distillate and residual fuel is a study by Bohi and Zimmerman which compiled the results of various demand studies (Bohi and Zimmerman, 1984). A study of demand elasticities for jet fuel was conducted by Dermot Gately, of New York University's Department of Economics (Gately, 1968). An energy model developed by DRI/McGraw-Hill, Inc. reports price elasticities of demand for motor gasoline (Gibbons, 1989).

The studies that we reviewed all used historical data to estimate demand elasticities, and most controlled for variations in non-price determinants of demand. As might be expected, there are disparities among the estimates reported in the literature. From the evidence that Bohi and Zimmerman examined, the level of aggregation of the data appears to be the single most important factor that accounts for variations in results among the studies. The specification of the demand functions (including the demand determinants included in the functions), the level of aggregation, and the time periods all vary by model and account for the disparity among estimates. Because price sensitivity depends on the particular petroleum product and the specific application for which the petroleum is used, the range of estimates compiled here are organized by petroleum product. The estimates are reported in a table at the end of this section.

Motor Gasoline

Bohi and Zimmerman report estimates of price elasticity of demand for gasoline centering around -0.43.

DRI developed its Energy Model to forecast vehicle demand for oil (Gibbons, 1989). In doing so, DRI developed a structure to analyze the primary determinants of fuel use within specific vehicle categories. Their model is based on the notion that the demand for motor fuels is derived primarily from the demand for travel and consumers' preferences for particular vehicles. The model takes into account that the decision to buy a vehicle is based on the current macroeconomic environment, as well as the price of fuels. In general, the higher the price level of gasoline, the greater the incentive on the part of consumers to opt for more fuel-efficient vehicles. DRI reports different demand elasticities for motor gasoline, depending on the type of vehicle using the fuel. For light trucks, they report an estimate of −0.026; for automobiles, −0.064; for medium trucks, −0.0288; and for heavy trucks, −0.0227.

DOE reports elasticity estimates for motor gasoline ranging from -0.1 to -0.3. These estimates are consistent with the estimates described above in that they suggest that the demand for gasoline is relatively inelastic.

<u>Jet Fuel</u>

Relatively few studies report estimates of demand elasticities for jet fuel. The effect of an increase in fuel costs on the airline industry depends on the ability of airlines either to cut fuel usage (by decreasing weight (carrying less fuel) and reducing speed) or to pass higher costs on to customers. Therefore, the price elasticity of demand for jet fuel depends both on the ability to conserve fuel and on the demand for travel.

Jet fuel demand has grown 46.5 percent since 1982 as air travel has increased and fuel efficiency has improved (DOE, 1991c). Historical data indicate that the demand for jet fuel is affected by changes in price. For example, as shown in Table 1-15, jet fuel consumption fell when real jet fuel prices rose substantially between 1979 and 1982.

Table 1-15

GROWTH RATES FOR JET FUEL DEMAND

	Average Annual Growth Rates (%)
Time Periods	Fuel Consumption
1965-1969	13.34
1969-1976	0.00
1976-1979	2.94
1979-1982	-2.21
1982-1986	6.51

Source: Dermot Gately (1988). *Taking Off: The U.S. Demand for Air Travel and Jet Fuel.* The Energy Journal. Vol. 9, No. 4.

Gately (1988) examines the extent to which changes in jet fuel prices affected demand and reports an estimated short-run demand elasticity for jet fuel of -0.10. (This is similar to the findings of some other authors who used earlier data, although there have also been higher estimates.) Also, Gately finds that price elasticity increases in absolute value with distance. We note, however, that however, Gately uses data that are highly aggregated across destinations, distances, and trip purposes.

Pindyck and Rubinfeld (1989) report estimates of short-run elasticities for jet fuel ranging from 0.0 to -0.15. These estimates suggests that demand for jet fuel as an input to the production of airline flight-miles is relatively inelastic. This conclusion is consistent with the estimates reported by Gately.

Distillate and Residual Fuel

There are few studies of commercial and industrial energy demand, and those available are hampered by the lack of detailed information on the way in which energy is used in these sectors. For example, data on residential consumption of fuel oil do not distinguish among consuming sectors, making it difficult to obtain reliable estimates of residential demand behavior. The only residential fuel oil study reviewed by Bohi and Zimmerman (1984) estimated demand from State-level data and reported a short-run price elasticity of demand of -0.18 to -0.19.

As noted above, the paucity of data on commercial and industrial energy consumption limited the studies of these sectors. Models use aggregate-level data, which are drawn from diverse sample populations. DOE reports estimated long-run price elasticities of -0.5 and -0.7 for wholesale purchases of both residual and distillate oil by commercial and industrial users.

Demand for fuel by electric utilities generally varies by location. For example, demand is more elastic for those areas having with the greatest proportion of dual-fired capacity, while the lower elasticity estimates are found in regions where a single fuel represents a high proportion of total fuel costs. Bohi and Zimmerman report price elasticity of demand estimates for industrial fuel oil ranging from -0.23 to -1.57.

DOE's estimates are taken from DOE/EIA's demand models whose results are published in *Short-Term Energy Outlook* (DOE, 1980). For distillate fuel consumption, there are limits in the short run as to the amounts of possible efficiency increases, decreased fuel utilization rates, and fuel switching that are required to achieve lower consumption as real prices increase. For long-term price elasticities, DOE/EIA uses several different models with different parameters. The ranges of price elasticities generated by these models for each fuel type are listed in Table 1-16. In all sectors and for all fuel types, the demand for petroleum products appears quite inelastic, particularly in the short run.

Summary of Demand Elasticities

Table 1-16 lists short-run and long-run demand elasticity estimates byr petroleum product and by sector (residential, commercial, industrial, and transportation). Bohi and Zimmerman presented their interpretation of the consensus estimates of price elasticities by fuel type and consuming sector, based on the studies they examined. Cases are labeled uncertain if there are not enough independent estimates on which to base a conclusion, or the range of estimates is so wide that the elasticity must be considered uncertain. Generally, long-run estimates show more variation than short-run estimates. Short-run elasticities for all petroleum products ranged from -0.1 to -0.4 in DOE's summary report.

These results indicate that the demand for gasoline is less elastic than the demand for other petroleum products. For non-transportation uses, the demand for distillate and other petroleum products is fairly price-inelastic in the short run, and perhaps slightly elastic in the long run. Generally, most available evidence indicates that the demand for petroleum products is relatively inelastic in the short run.

Past and Present Supply and Consumption

Domestic supply is comprised of domestic production, imports, and stock draw-off, less exports and stock additions. By definition, this measure is also equal to domestic consumption. Table 1-17 shows petroleum product supply and its components since 1980. Historically, motor gasoline has been the product that comprises the largest share of total supply. Table 1-18 lists the percentage of refinery yield of different petroleum products from 1991 through 1995. The data show that the yields for most products has been relatively stable, but significant regulatory costs could cause some reshuffling of the product slate.

The supply of residual fuel oil has decreased steadily since 1980. This decrease in residual fuel supply reflects a move in the industry from heavier fuels toward lighter, more refined versions. This trend is expected to continue into the future as efforts to control air emissions go into effect. All other types of fuel show increases in use, including jet fuel. Substantial gains in airplane fuel efficiency in the last two decades, which have resulted from improved aerodynamic design and a shift toward higher seating capacities, have been exceeded by even faster growth in passenger miles traveled (Gately, 1988). All major petroleum products registered lower demand in 1991 than in 1990, except liquified petroleum gas. This was the first time since 1980 that demand for all major petroleum products fell simultaneously in the same year. In 1991, decreased demand was brought on by warmer winter temperatures, an economic slowdown, and higher prices resulting from the Persian Gulf situation (DOE, 1991c).

Table 1-16

PRICE ELASTICITIES OF DEMAND FOR PETROLEUM PRODUCTS

Data Source	Fuel Sector/Type	Short-Run Elasticity Range	Long-Run Elasticity Range
DOE's literature review	Sector:		
	Residential	-0.10 to -0.40	-0.50 to -1.10
	Commercial	-0.10 to -0.40	-0.50 to -1.10
	Industrial	-0.10 to -0.40	-0.60 to -2.80
	Transportation	-0.10 to -0.30	-0.30 to -0.90
DOE's *Short-Term Energy Outlook (STEO)**	Fuel Type:		
	Distillate	-0.43	-0.50 to -0.99
	Motor Gasoline	-0.16	-0.55 to -0.82
	Residual -		
	Nonutility	-0.19	-0.61 to -0.74
	Utility	-0.53	-0.61 to -0.74
Bohi and Zimmerman	Sector:		
	Residential	-0.18 to -0.19	uncertain
	Commercial	-0.20 to -1.5	uncertain
	Industrial	-0.23 to -1.57	uncertain
	Transportation	-0.43	0.7
Gately, NYU	Jet Fuel	-0.10	--**
Pindyck and Rubinfeld	Jet Fuel	0 to -0.15	--
DRI/McGraw-Hill, Inc.	Gasoline:		
	Automobiles	-0.064	--
	Light Trucks	-0.026	--
	Medium Trucks	-0.029	--
	Heavy Trucks	-0.023	--

Notes: *Long-run elasticity estimates are presented as a range over all STEO models.

**Source did not estimate long-run elasticity.

Table 1-17

U.S. PETROLEUM PRODUCTS SUPPLIED, 1980-1995

(Million barrels per day)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquified Petroleum Gases	Other Products	Total
1980	6.58	1.07	2.87	2.51	1.47	2.57	17.07
1981	6.59	1.01	2.83	2.09	1.47	2.08	16.07
1982	6.54	1.01	2.67	1.72	1.50	1.86	15.30
1983	6.62	1.05	2.69	1.42	1.51	1.94	15.23
1984	6.69	1.18	2.84	1.37	1.57	2.07	15.72
1985	6.83	1.22	2.87	1.20	1.60	2.01	15.73
1986	7.03	1.31	2.91	1.42	1.51	2.09	16.27
1987	7.21	1.38	2.98	1.26	1.61	2.22	16.66
1988	7.34	1.45	3.12	1.38	1.66	2.33	17.28
1989	7.33	1.49	3.16	1.37	1.67	2.31	17.33
1990	7.24	1.52	3.02	1.23	1.56	2.42	16.99
1991	7.19	1.47	2.90	1.16	1.69	2.27	16.68
1992	7.27	1.45	2.98	1.09	1.76	2.47	17.02
1993	7.48	1.47	3.04	1.08	1.73	2.43	17.23
1994	7.60	1.53	3.16	1.02	1.88	2.52	17.71
1995	7.79	1.51	3.21	0.85	1.90	2.46	17.72

Source: Petroleum Supply Annual, 1995.

Table 1-18

REFINERY YIELDS, 1991-1995

	(percentage of total yield)				
Products	1991	1992	1993	1994	1995
Liquefied Refinery Gases	3.8	4.3	4.1	4.2	4.5
Finished Motor Gasoline	45.7	46.0	46.1	45.5	46.4
Finished Aviation Gasoline	0.2	0.2	0.2	0.2	0.2
Naphtha-Type Jet Fuel	1.2	1.0	0.8	0.3	0.1
Kerosene-Type Jet Fuel	9.1	8.9	9.2	9.8	9.7
Kerosene	0.3	0.3	0.3	0.4	0.4
Distillate Fuel Oil	21.3	21.2	21.9	22.3	21.8
Residual Fuel Oil	7.0	6.4	5.8	5.7	5.4
Naphtha for Petrochemical Feedstock Use	0.9	1.2	1.0	1.1	1.2
Other Oils for Petrochemical Feedstock Use	2.0	2.1	2.0	1.8	1.7
Special Naphthas	0.4	0.4	0.4	0.4	0.3
Lubricants	1.1	1.1	1.1	1.2	1.2
Waxes	0.1	0.1	0.1	0.1	0.1
Petroleum Coke	4.1	4.2	4.3	4.3	4.3
Asphalt and Road Oil	3.0	3.0	3.2	3.1	3.2
Still Gas	4.7	4.7	4.6	4.6	4.5
Miscellaneous Products	0.5	0.3	0.3	0.3	0.3
Processing Gain (-) or Loss (+)	-5.1	-5.5	-5.4	-5.3	-5.3

Source: Petroleum Supply Annual, 1995, 1994, 1993, 1992, 1991.

MARKET OUTLOOK

Below we describe the market outlook for the petroleum refining industry. First, we discuss factors affecting future market supply. We then examine the outlook for demand or consumption of refined products. Finally, we describe expected future trends in refined product prices. Much of the discussion in this section relies on DOE's Annual Energy Outlook for 1996 (AEO96) Forecast.

Supply Outlook

Exogenous factors that increase the cost of refining products will affect the future market supply in the petroleum market. Below, we discuss the outlook of two of the most important of these, clean air regulations and the price of crude oil. Also, we describe future expected additions to refining capacity which will affect both the amount and mix of products that can be refined. We note that additions to capacity are endogenous in that they are determined by expected future prices of refined products.

Clean Air Act Requirements

While several air quality regulations are likely to affect the refining industry in the future, the reformulated gasoline program is expected to receive the most attention. Reformulated gasoline has been mandated in several areas of the country since 1995. Beginning in 1998, reformulated gasoline must comply with EPA's "complex model" which requires reductions in several emissions. Additional emission reductions will be required by 2000. Also, traditional gasoline must meet an "anti-dumping" requirement in that it must burn as cleanly as 1990 gasoline. DOE expects the complex model and anti-dumping requirements to add 3 to 5 cents to the per-gallon price of gasoline by 2000 (DOE, 1996b).

Producing larger amounts of reformulated gasoline will require substantial changes to refinery operations, such as modifying operations of existing units and adding new refining capacity. The extent to which this program will affect the future supply of refined petroleum products will depend in part on the opportunities that EPA grants other ozone nonattainment areas to opt-in to the program.

Reformulated gasoline requirements initially apply only to the nine ozone nonattainment areas with the highest ozone design values during the period from 1987 to 1989. Any other ozone nonattainment area can opt-in to the program at the request of the governor of the State in which it is located. EPA may delay the opt-in of some States by up to 3 years if, after consultation with DOE, it determines that there is insufficient domestic capacity to produce the reformulated gasoline needed to supply opt-in areas. Recent data show 19 areas that are in nonattainment with the ozone standard promulgated in July 1997.[7]

Costs associated with this program include costs for the addition of oxygenates, the control of benzene, aromatics, sulfur, (RVP) levels, and other parameters that refiners may adjust to meet program requirements. Cambridge Energy Research Associates (CERA) concluded that the 1995 reformulated gasoline requirements do not appear to pose significant technical problems to the industry, although the percentage of production that refiners plan to reformulate varied widely based on their market position and perception of future opt-ins (CERA, 1992). The annual nationwide costs for reformulated gasoline in ozone nonattainment areas are a direct function of the amount of fuel consumed in the areas requiring its use. Nationwide costs will also depend upon the extent to which nonattainment areas opt-in to the program.

The Federal alternative fuel programs include provisions for fleet clean fuels in 21 ozone/CO nonattainment areas and the California general vehicle clean fuels program. The general vehicle clean fuels program, if successful in California, may be broadened to include other States. This program could have long-range effects on motor gasoline demand and, subsequently, on petroleum refining. The State of California's motor vehicle control program is more likely to affect refineries than the Federal alternative fuels programs. Low emission vehicle standards have been adopted in California that could be met with any combination of technologies and fuels;

[7] Mathtech (1997), Table C-1.

vehicle manufacturers will ultimately determine the technologies and fuels that will be used to meet these standards.

It is difficult to predict the impact of the clean fuels program on the U.S. supply of refined petroleum products, given the uncertainty as to whether California's program will be adopted in areas other than where it is mandated. For example, if only selected areas of the country will be required to use alternative fuels, refiners will be forced to alter their production and distribution based on regional markets.

Overall, refineries are projecting large capital investments over the next decade to comply with the CAA programs. Recognizing the possibility that other markets may be permitted to opt-in to the reformulated gasoline program, several firms are projecting capital investment to prepare their refineries to produce as much reformulated gasoline as possible, even if they do not directly supply gasoline to any of the nine worst ozone nonattainment areas. Other firms, particularly smaller refineries, have postponed any firm capital investment plans pending final decisions on the number of States which will opt-in to the program.

To meet the new regulations, domestic refiners will be likely to either modify existing facilities or expand downstream operations. For example, more ether, isomerization, and alkylation units will be necessary to produce gasoline components. Additional hydroprocessing and hydrocracking units will need to be added to convert unfinished oils into lighter, cleaner hydrocarbons (DOE, 1996b).

One obstacle common to each of these new regulations is the need for the refining industry to develop expanded storage and distribution systems for the new fuels. For example, reformulated gasoline will need to be stored in separate storage tanks, as will low- and high-sulfur diesel fuels. One possibility is that refineries could use existing storage tanks to hold higher RVP fuels. Oxygenates, which are difficult to transport through existing U.S. pipeline systems, will also need to be stored in tanks.

World Crude Oil Prices

Changes in crude oil prices significantly affect the costs of refined products. For example, DOE estimates that crude oil costs of gasoline were less than 40 cents per gallon in 1994. However, because of higher crude prices, DOE predicts that, by 2015, the crude oil content of gasoline will increase to about 60 cents (DOE, 1996b).

DOE's AEO96 forecasts world crude prices out to 2015 for a reference (baseline), for high and low economic growth scenarios. The average annual percentage increases in crude oil prices for the three forecast scenarios are:[8]

- Reference case — 2.4 percent.
- High economic growth — 2.7 percent.
- Low economic growth — 2.1 percent.

DOE expects domestic crude oil production to decline through 2005, but to increase after than as accumulating technological advances and rising prices stimulate faster crude recovery. They predict that onshore production will decrease at an average annual rate of 1.7 percent over the 1994-2005 period, then increase at a rate of 1.3 percent annually through 2015. Offshore production is expected to decline at an average rate of approximately 0.7 percent throughout the forecast period. Crude output from Alaska is expected to decline at an average annual rate of 3.5 percent between 1994 and 2015. However, increased domestic production from enhanced oil recovery is expected to slow the overall downward trend (DOE, 1996b).

Refining Capacity

DOE projects refinery capacity will grow by 2015, ranging from 0.9 million barrels per day in the low economic growth case to 2.0 million barrels per day in the high growth case. The economic growth scenarios reflect different assumptions about petroleum consumption and refined product imports, which in turn, drive the capacity projections. DOE expects that refineries will continue to be used intensively, at 90 to 94 percent of capacity. These rates are comparable to recent utilization rates, but higher than those observed in the 1980s and early 1990s. DOE expects

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[8] See Pechan and Mathtech (1997) for a description of the assumptions underlying DOE's three growth rate scenarios.

current and future investments in equipment for desulfurization, alkylation, isomerization, coking, and other processes will allow U.S. refineries to process lower quality crude oils in the future. The ability to do so will become increasingly important as higher quality crude reserves are depleted over time (DOE, 1996b).

However, DOE does not expect the growth in domestic refining capacity to keep pace with consumption. As a result, they expect increases in net imports of refined products. Depending on the economic growth scenario, they predict growth in refined product imports ranging between 0.6 and 3.0 million barrels per day by 2015 (DOE, 1996b).

Demand Outlook

Short-run fluctuations in the demand for refined petroleum products depend largely on variations in weather, but long-run changes in future demand are primarily determined by economic growth and technological changes that affect energy use efficiency. DOE's AEO96 has projected consumption of various refined products over the period 1994 through 2015. Table 1-19 shows the annual average percentage increase in consumption over this period for the three economic growth rate scenarios — low growth, the reference case, and high growth. For example, DOE forecasts average annual rates of increase in the consumption of gasoline ranging from 0.3 to 0.8 percent, depending on the economic growth scenario.

Table 1-19

DOE PROJECTIONS OF REFINED PETROLEUM PRODUCT CONSUMPTION
(Average Percent Annual Growth Rate, 1994-2015)

Product	Low Economic Growth	Reference Case	High Economic Growth
Motor Gasoline[a]	0.3%	0.6%	0.8%
Jet Fuel[b]	1.4	1.9	2.4
Distillate Fuel	0.8	1.2	1.6
Residual Fuel	0.9	1.2	1.4
Liquified Petroleum Gas	0.4	0.9	1.3
Other[c]	0.2	0.5	0.8

Notes: [a] Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[b] Includes naphtha and kerosene type.
[c] Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum code, and miscellaneous petroleum products.

Source: *Annual Energy Outlook*, 1996, U.S. Department of Energy, Table B2.

Among the various refined products, DOE projects the strongest growth in the consumption of jet fuel. In 1994, gasoline accounted for about 61 percent of total motor vehicle consumption of refined products. However, DOE expects gasolines share of vehicle consumption to fall to about 53 percent by 2015, largely because of increases in the consumption of jet and diesel fuel (DOE, 1996b).

Price Outlook

Future prices of refined products depend, of course, on market demand and supply. Table 1-20 shows DOE's AEO96 forecasts of refined product prices over the period 1994 through 2015. For example, DOE expects that the price of motor gasoline to increase by an average annual rate of 0.6 to 1.2 percent, depending on the economic growth scenario. As Table 5-3 indicates, the largest percentage increases in prices are expected for jet fuel and residual fuel.

Table 1-20

DOE PROJECTIONS OF REFINED PETROLEUM PRODUCT PRICES
(Average Percent Annual Growth Rate, 1994-2015)

Product	Low Economic Growth	Reference Case	High Economic Growth
Motor Gasoline[a]	0.6%	0.9%	1.2%
Jet Fuel[b]	1.9	2.3	2.7
Distillate Fuel	0.6	0.9	1.2
Residual Fuel	2.0	2.3	2.6
Liquified Petroleum Gas	0.8	1.1	1.3

Notes: [a] Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[b] Includes naphtha and kerosene type.

Source: *Annual Energy Outlook*, 1996, U.S. Department of Energy, Table B12.

We caution that future prices of refined products depend on future events affecting demand and supply. Some of these events are difficult to predict. For example, crude oil prices, which affect the supply of refined products, can be affected significantly by highly uncertain international events. We do note, however, that DOE's price predictions account for estimates of the effects of the reformulated gasoline program.

SMALL BUSINESSES IN THE PETROLEUM REFINING INDUSTRY

The Regulatory Flexibility Act of 1980 (RFA), as amended by the Small Business Regulatory Enforcement Act of 1966 (SBREFA), requires EPA to determine whether proposed regulations will have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governments and small organizations (e.g., non-profit organizations). The Small Business Administration (SBA) defines businesses by Standard Industrial Classification (SIC) codes and typically defines business sizes by measures such as employment or sales. SBA classifies petroleum refineries as small if corporate-wide employment is less than 1,500 *and* daily crude processing capacity is less than 75,000 b/cd.[9]

[9] See Federal Register (61 FR 3175), January 31, 1996 for SBA size standards.

A recent survey by the National Petroleum-Refiners Association (NPRA) identifies 22 firms as satisfying SBA's criteria for small business status.[10] We have been able to identify the operating characteristics of refineries operated by 16 of these firms by cross-referencing the NPRA list with data reported in a recent Oil & Gas Journal (1996) survey.[11]

Table 1-21 compares the characteristics of small and large (firms not identified as small) businesses in the petroleum refining industry. For example, refineries operated by small businesses have an average complexity factor of 2.10 compared with 15.06 for refineries operated by large businesses. This indicates the refineries operated by small businesses tend to have substantially less ability to vary product mix than refineries operated by large businesses. Also, small businesses in the petroleum refining industry tend to operate plants with smaller capacities, employ fewer workers and operate fewer plants than large businesses.

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[10] NPRA (1997). See Appendix B of this report.

[11] One of the firms listed in the NPRA survey is not a small business by the SBA definition. However, the facility it operates is a small refinery according to Section 410(h) in Title IV of the 1990 Clean Air Amendments. This section provides a separate category for small diesel fuel producing refineries. The remaining 5 firms identified in the NPRA survey are not included among the 90 firms in the Oil & Gas Journal survey. Assuming 96 firms operate refineries nationwide, the NPRA survey suggests that about 23 percent of all firms quality as small businesses.

Table 1-21

COMPARISON OF CHARACTERISTICS BETWEEN SMALL AND LARGE BUSINESSES IN THE PETROLEUM REFINING INDUSTRY

CHARACTERISTIC	SMALL BUSINESSES[a]	LARGE BUSINESSES[b]
Average Complexity Factor	5.85	15.06
Average Capacity per Plant (b/cd)	21,724	138,392
Average Capacity per Firm (b/cd)	28,992	202,280
Average Employment per Plant[c]	111	683
Average Employment per Firm[d]	143	998
Average Number of Plants Operated per Firm	1.19	1.95

Notes: [a] Operating characteristics for small businesses are based on 16 of the 22 small firms identified in the NPRA survey. The operating characteristics of the other 6 small firms are unknown.

[b] Defined as firms not qualifying as small businesses.

[c] Estimated as industry employment per barrel of crude capacity in 1992 (U.S. Census of Manufactures) times plant capacity. Estimated are adjusted for differences in capacity utilization between 1992 and 1996.

[d] Employment in petroleum refining sector. Excludes employment in other sectors.

Sources: Small business are identified in NPRA (1997). Operating characteristics computed from data in the *Oil and Gas Journal* (1996).

Table 1-22 shows how many of the refineries operated by small businesses are expected to be affected by the proposed NESHAP. The 16 small businesses operate 19 petroleum refineries. Of these 2 refineries operated by 2 different firms are expected to be affected by the proposed NESHAP. A refinery is affected if it is expected to incur compliance costs as a result of the implementation of the NESHAP.

Table 1-22

PRELIMINARY COUNTS OF AFFECTED SMALL BUSINESSES AND REFINERIES

	Counts of Small Businesses/Refineries
Small Businesses	16[a]
Refineries Operated by Small Businesses	19
Affected Small Businesses	2
Affected Refineries Operated by Small Businesses	2

Sources: Small businesses identified by NPRA (1997). Affected firms identified in EPA (1997b).

[a] Includes 16 of 22 small businesses identified in NPRA (1997).

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CHAPTER 2

HAP EMISSION SOURCES AND COMPLIANCE COSTS

Section 112 of the Clean Air Act (CAA) lists source categories of major and area sources of hazardous air pollutants (HAPs) for which regulations must be developed. The U.S. Environmental Protection Agency (EPA) is currently preparing a National Emission Standard for Hazardous Air Pollutants (NESHAP) for emission sources in petroleum refineries.

The refining industry has developed a complex variety of production processes used to transform crude oil into its various final forms, many of which are already subject to some CAA controls. Section 112 of the CAA contains a list of HAPs for which EPA has published a list of HAP source categories that must be regulated. Refinery HAP sources include fluid catalytic cracking units, catalytic reforming units, and sulfur plant units. None of these sources is currently controlled by existing NESHAPs. The subject NESHAP will therefore regulate emissions from these refinery sources.

The proposed NESHAP evaluated in this report represents the maximum achievable control technology (MACT) "floor." The MACT floor is the level of control that is the minimum stringency for a NESHAP that can be developed in accordance with Section 112(d) of the Clean Air Act.

HAP EMISSION SOURCES

The HAP emission sources of interest for the subject NESHAP are the process vents for fluid catalytic cracking units (CCUs), catalytic reforming units (CRUs), and sulphur recovery units (SRUs). HAP emissions from CCUs include metal HAP that are deposited on the catalyst particles and organic HAP that result from incomplete combustion. As a result, two different types of control technologies are required.[1] As of January 1997, the domestic catalytic cracking (fluid and non-fluidized) charge capacity was about 5.2 million b/cd.[2] While 105 refineries

[1] RTI (1997).

[2] See Mathtech (1997), Appendix A, for detailed operating characteristics of domestic petroleum refineries.

operate either fluid or non-fluidized units, fluid CCUs dominate the domestic industry.[3] Nine refineries report CCU charge capacities of less than 10,000 b/cd and 9 others report capacities greater than 100,000 b/cd.

CRU process vent emissions can occur at three different points. These are the initial depressurization and purge vent; the coke burn pressure control vent; and the final catalyst vent.[4] As of January 1997, 124 domestic refineries reported operating CRUs with a combined capacity of about 3.64 million b/cd. Twelve refineries reported CRU capacities of less than 5,000 b/cd and 21 operate CRUs with capacities of 50,000 b/cd or more.

The HAP emissions of SRU process vents include carbonyl sulfide (COS) and carbon disulfide (CS_2). Both HAP components are by-products of reactions in SRU reactors. COS may also result from incomplete combustion from a thermal oxidizer.[5] As of 1992, about 130 U.S. refineries operated sulphur production units having a combined capacity of about 20,500 Mg/day. Of these, 52 reported sulphur production capacities smaller than 50 Mg/day, 24 had capacities exceeding 300 Mg/day, and 5 reported capacities in excess of 500 Mg/day.[6]

COMPLIANCE COSTS

There are 164 U.S. petroleum refineries included in this analysis. Of these, 127 refineries will be affected in that they are expected to incur compliance costs as a result of the implementation of the proposed NESHAP.

Table 2-1 provides a summary of estimated compliance costs.[7] Compliance costs include the costs of purchasing and installing emission control equipment, annual operating and maintenance costs, and monitoring and record-keeping costs. As Table 2-1 indicates, affected

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[3] RTI (1996).

[4] RTI (1997).

[5] RTI (1997).

[6] *Chemical Economics Handbook* (1992) as cited in RTI (1997).

[7] See Appendix C for refinery-specific estimates of compliance costs.

refineries are expected to incur average capital costs of $1.42 million, average annual operating and maintenance costs of about $ 280 thousand, and average annualized costs of about $420 thousand.[8] Estimated industry-wide capital costs total about $181.32 million while annualized costs total about $53.52 million.

Table 2-1

SUMMARY OF ESTIMATED COMPLIANCE COSTS
($ 1996 million)

	Capital Costs	Annual Operating and Main tenance Costs	Annualized Costs[a]
Average Cost per Affected Refinery[b]	1.42	0.28	0.42
Industry Total Costs	181.32	35.54	53.52

Note: [a] Capital costs annualized at a 7 percent discount rate.
[b] Industry total costs averaged over 127 refineries expected to incur compliance costs.

Source: Computed from data in EPA (1997b).

[8] Capital costs annualized at a 7 percent discount rate.

CHAPTER 3

ECONOMIC IMPACT ANALYSIS METHODOLOGY

We assess the economic impacts associated with the proposed NESHAP by conducting analyses of the petroleum refining industry. We describe the methods employed in these analyses below.

OVERVIEW OF DISTRIBUTIONAL IMPACTS

As noted earlier in the introduction to this report, several groups might potentially suffer from adverse impacts associated with the proposed NESHAP. These groups include:

- Petroleum refiners.
- Buyers of refined petroleum products.
- Employees at affected refineries.
- Individuals affected indirectly by the proposed NESHAP.

We describe the potential adverse impacts affecting each of these groups below.

Impacts on Producers

As affected producers purchase, install and operate emission control equipment or change production practices to comply with the NESHAP, their costs will increase, reducing the profitability of at least some of the affected plants. However, a portion of the compliance costs can be passed on to consumers through increased product prices. Ultimately, the magnitude of the adverse impacts incurred by affected plants will depend on the extent to which control costs can be passed on to buyers.

Some plants in the affected industry may realize benefits from the implementation of an emission control standard. The post-control profitability of an affected plant will improve if post-control price increases more than offset the plant's compliance costs. This could occur if compliance costs for some plants are substantially higher, per unit of output, than those for other plants in the industry. Also, plants not affected by the standard may enjoy the benefit of higher market prices without incurring the additional costs associated with compliance.

Impacts on Consumers or Buyers

Some refined petroleum production is purchased directly by consumers and some by firms which use refined products as inputs to produce other goods. These buyers and the consumers of the goods which they produce are likely to suffer from two related adverse impacts. First, post- control prices for refined products are likely to be higher as sellers attempt to pass through compliance costs to their customers. This will cause profits to be smaller, at least in the short run, for firms which purchase refined products as inputs to other final goods and services. It will also cause prices of final goods and services to be higher as firms using refined products as inputs attempt to pass through some of the increase in their production costs. Second, the shift in supply caused by compliance costs is likely to reduce the amount of refined products sold in petroleum markets, as well as the level of output sold in markets which use refined petroleum as inputs. These two effects are related in that post-control equilibrium prices and output levels in affected markets will be determined simultaneously.

Indirect or Secondary Impacts

Two countervailing impacts on employees of affected plants are likely to result from the implementation of the proposed NESHAP. Employment will fall if affected plants either reduce output or close operations altogether. If this occurs, firms that supply inputs (e.g., crude oil suppliers) to petroleum producers might also suffer adverse impacts. On the other hand, in-creases in employment associated with the installation, operation, maintenance and monitoring of emission controls are likely. Also, firms that produce substitutes to refined petroleum products could benefit from reduced foam production.

A number of other indirect or secondary adverse impacts may be associated with the implementation of a standard. The indirect impacts we consider in this study include: impacts on foreign trade, regional economies, and effects on energy consumption at petroleum refineries. We also assess potential small business impacts.

ECONOMIC IMPACT STUDIES

The industry segment studies that follow in this report include four major components of analysis. These components or phases of analysis, which are designed to measure and describe economic impacts, are:

- Direct impacts (market price and output, domestic production and plant closures).
- Capital availability analysis.
- Evaluation of secondary impacts (employment, foreign trade, energy consumption, and regional and local impacts).
- Analysis of potential small business impacts.

Each of these analyses is described below.

PRIMARY IMPACTS

We employ a partial equilibrium analysis of the petroleum refinery industry to estimate the primary impacts of compliance costs. These primary impacts include market equilibrium prices, market output levels, the value of domestic shipments, and the number of potential plant closures.[1] This analysis is so named because the predicted impacts are driven by estimates of how the affected market achieves equilibrium after the implementation of the proposed NESHAP.

Many petroleum refineries produce a multiple-product slate of refined products including, for example, motor gasoline, distillate and residual fuel oil and petroleum coke. However, the proposed NESHAP is not linked to any one specific product; that is, refiners cannot avoid compliance costs by altering the mixes of their product slates. The upshot is that refiners will invest in emission control equipment and continue production if the expected future net revenue from the joint product slate (i.e., net revenue from all refined products taken together) are

[1] The results of the partial equilibrium analyses are also used to estimate employment, energy and foreign trade impacts and the economic costs associated with the regulatory alternatives.

sufficient to offset compliance costs. This means that the relevant market for this study is the market for refined products jointly.

In a competitive market, equilibrium price and output are determined by the intersection of demand and supply. The supply function is determined by the marginal (avoidable) operating costs of existing plants and potential entrants. A plant will be willing to supply output so long as market price exceeds its average (avoidable) operating costs. The installation, operation, maintenance and monitoring of emission controls will result in an increase in operating costs. An associated upward shift in the supply function will occur. The procedures employed in the market analysis are illustrated in Figure 3-1. Constructing the model and predicting impacts requires completing the following four tasks.

- Estimate pre-control market demand and supply functions.
- Estimate per unit emission control costs.
- Construct the post-control supply function.
- Solve for post-control price, output and employment levels, and predict plant closures.

We briefly describe each of these tasks below.[2]

Pre-Control Market Demand and Supply Functions

Pre-control equilibrium price and output levels in competitive markets are determined by market demand and supply. When the supply curve shifts because of compliance costs, the economic impacts are driven primarily by market demand and supply elasticities.

[2] See Appendix B for more detailed descriptions of the data and methods employed in the partial equilibrium analysis.

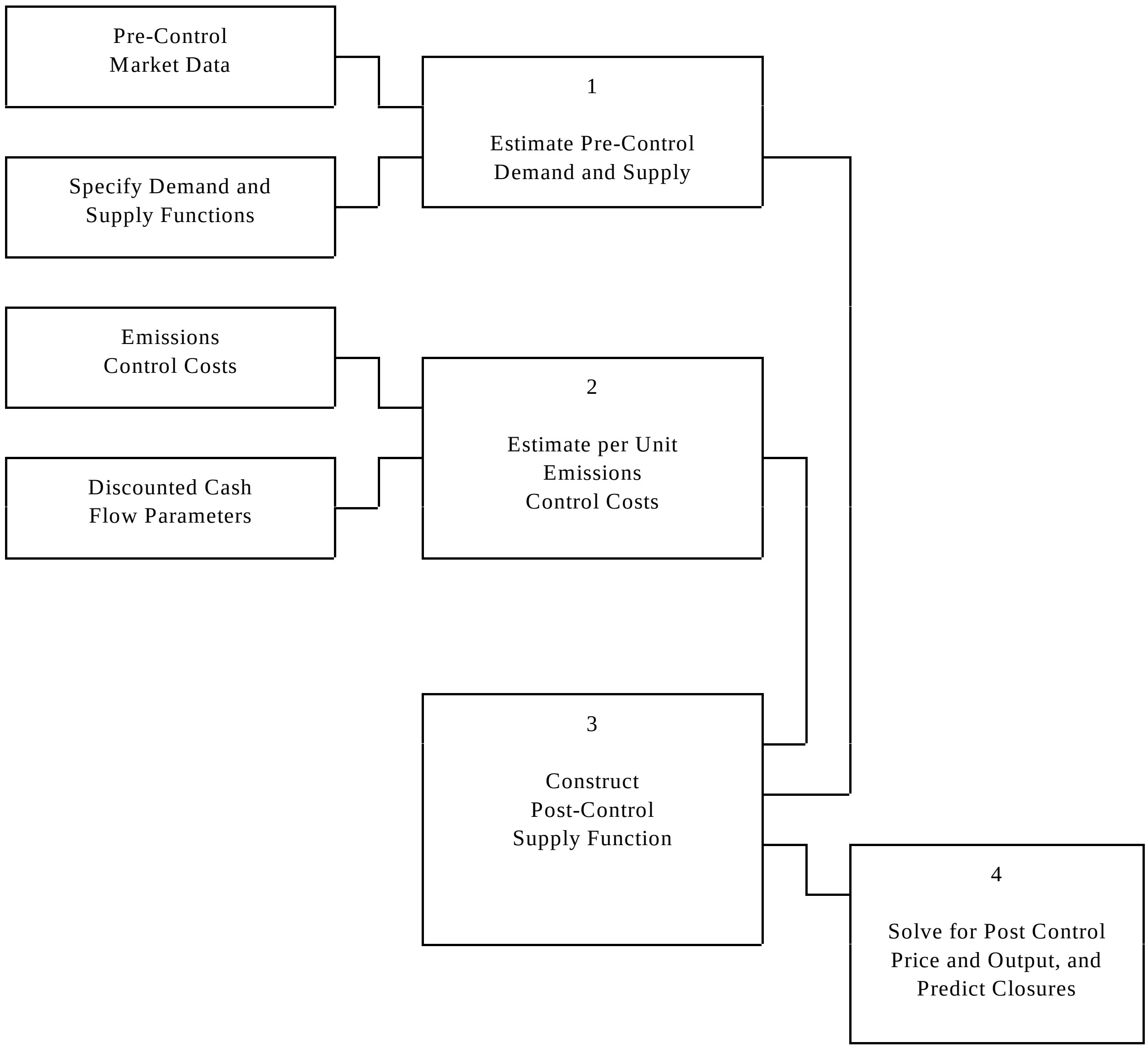

Figure 3-1

Partial Equilibrium Analysis of Petroleum Refining Industry

The base case economic impacts presented in this report use a demand elasticity estimate for refined products of −0.65. This estimate is a production-weighted average of the mid-points of ranges of demand elasticity estimates reported in the economic literature for major refined products.[3] The sensitivity analyses presented in Appendix A use high and low demand elasticity estimates of −0.79 and −0.50, respectively.

We use an estimated supply elasticity of 1.24 taken from Pechan and Mathtech (1994) for the base case estimates of economic impacts presented in this report. This is an estimate of supply elasticity for the joint refined product slate. The sensitivity analyses reported in Appendix A use high and low supply elasticity estimates of 1.50 and 1.00, respectively.

Per Unit Compliance Costs

Compliance costs will cause an upward vertical shift of the supply curve in markets for refined petroleum products. The height of the vertical shift for each affected plant is given by the after-tax cash flow required to offset the per unit increase in production costs resulting from the installation, maintenance, operation and monitoring of emission control equipment.

Estimates of the capital, operating, maintenance and monitoring costs associated with emission controls for affected plants are reported in Appendix C. Per unit, after-tax costs are estimated by dividing after-tax annualized costs by annual output.[4] This cost reflects the off-setting cash flow requirement which, in turn, yields an estimate of the post-control vertical shift in the supply function.

Computing per unit after-tax control costs requires, as inputs, estimates of the following parameters:

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[3] See Appendix B for a more detailed description of how this estimate is computed.

[4] Our use of after-tax costs is consistent with the assumption that firms attempt to maximize after-tax profits. An alternative view is that what matters to the firm are costs net of any adjustments for taxes. Thus, the use of after-tax costs is consistent both with rational behavior by affected firms and our objective of predicting how the market will respond to implementation of the regulatory alternatives.

- The useful life of emission control equipment.
- The discount rate (marginal cost of capital).
- The marginal corporate income tax rate.

The expected life of emission control equipment is 10 or 20 years, depending on the control technology. The economic impacts presented in this report are based on a 10 percent real private discount rate[5] and a 25 percent marginal tax rate.

The Post-Control Supply Function

Estimated after-tax per unit control costs are added to pre-control supply prices to determine the post-control supply prices for affected producers. We construct the post-control domestic supply function by sorting affected plants, from highest to lowest, by per unit post-control costs. We assume that plants with the highest per unit compliance costs are marginal (i.e., have the highest cost) in the post-control market. We define the "marginal" plant as the plant with the highest per unit operating costs in the market. As price adjusts to competition among producers, unprofitable producers exit the market until price rests at equilibrium. At equilibrium, the market price must be high enough to cover the per unit avoidable costs of the marginal plant, the highest-cost plant remaining in the market.

Constructing the post-control supply function requires estimates of the production levels at individual refineries. Our estimates of production levels are based on responses to the 1992 RCRA 3007 Questionnaire which reports plant-specific production for the following ten major refined products:

- Ethane/Ethylene.
- Propane/Propylene.
- Isobutane.

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[5] The discount rate referred to here measures the private marginal cost of capital to affected firms. This rate, which is used to predict the market responses of affected firms to emission control costs, should be distinguished from the social cost of capital. The social cost of capital is used to measure the economic costs of compliance. See Section 7 for a more detailed discussion of this issue.

- Motor gasoline.
- Jet fuel.
- Distillate fuel oil.
- Residual fuel oil.
- Asphalt and road oil.
- Petroleum coke.

Together, these 10 major products accounted for about 94 percent of total 1992 production at U.S. refineries.

We made two adjustments to the raw data for this analysis. These include:

- We adjusted the refinery-level production slates for changes in the product mix since 1992.[6]

- We constructed a single output measure for each refinery as the sum of the production levels of the ten major products weighted by their respective prices. This measure can be interpreted as a composite physical index of output at a normalized one dollar price.[7] It is also an estimate of refinery-specific revenues.

About 13 percent of the 164 refineries included in this analysis could not be linked with the RCRA survey. We estimate production at these refineries assuming their capacity utilization rates and product slate mixes are at industry-wide averages.

Post-Control Prices, Output, and Closures

The baseline, pre-control equilibrium output in an affected market is taken as the level of observed national consumption. We compute post-control equilibrium price and output levels in affected markets by solving for the intersection of the market demand curve and the market post-control, segmented supply curve. The estimated reduction in market output is given by the difference between the observed pre-control output level and the predicted post-control output

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[6] See Appendix B for a description of adjustments to the product slate mix.

[7] In general, we can normalize prices to any arbitrary value. For example, if the price of a refined product is $30/bbl, then $1 is the price of 1/30th of a barrel.

level. Similarly, the estimated increase in price is taken as the difference between the observed pre-control price and the predicted post-control equilibrium price.

Reporting Results of Market Analysis

The results of the partial equilibrium market analysis are presented in Section 4 of this report. In particular, estimates of the following are reported:

- Price increase.
- Reduction in market output.
- Annual change in the value of domestic shipments.
- Number of plant closures.

Limitations of the Market Analysis

The partial equilibrium model has a number of limitations. First, a single national market for refined petroleum products is assumed in the analysis. However, because of transportation costs and product specialties, many refineries operate in smaller regional markets. Regional markets will be affected primarily by cost changes of plants in the region, rather than all plants in the national market. Output reductions and price effects will vary across regions depending on locations of affected plants. The assumption of a national market is likely to cause predicted refinery closures to be overstated to the extent that affected firms are protected somewhat by regional trade barriers (e.g., due to advantages in transportation costs).[8]

Second, the analysis adopts a worst-case assumption that plants with the highest per unit compliance costs are marginal post-control. This assumption produces an upward bias in estimated effects on industry output and price changes because the compliance costs of non-marginal plants will not affect market price. This assumption also results in predicted closures to be overstated. Plants with the highest per unit compliance costs might not be marginal if other

[8] Our regional analysis described later in this section assesses the implications of assuming a national market.

plants with lower per unit emission control costs experience higher baseline costs. These other plants would be marginal if higher baseline costs more than offset the lower compliance costs.

Third, the analysis assumes that the implementation of controls does not induce any domestic producers to expand production. An incentive for expansion would exist if some plants have post-control incremental unit costs between the baseline price and the post-control price predicted by the partial equilibrium analysis. Plants unaffected by the standard may indeed face this incentive to expand production. Expansion by domestic producers will result in reduced impacts on industry output and price levels. While plant closures will increase as expanding producers squeeze out plants with higher post-control costs, net closures (closures minus expansions) will be reduced.

Fourth, this analysis estimates the marginal effects only of the subject NESHAP. In particular, we do not consider the joint impacts of this NESHAP and other environmental regulations of petroleum refining whose effects on the market have not yet occurred.

Fifth, our measure of output at affected refineries includes only the ten major products included in the RCRA survey. As a result, our analysis tends to overstate adverse impacts on refineries to the extent that additional revenues earned from the production of other refined products are available to cover compliance costs.

Finally, estimates of demand and supply elasticities are subject to modeling and statistical error. In the analyses reported in Appendix A, we assess the sensitivity of the estimated impacts to ranges of values for the elasticities.

CAPITAL AVAILABILITY ANALYSIS

We assume in the market analysis that affected firms will be able to raise the capital associated with controlling emissions at a specified marginal cost of capital. The capital availability analysis, on the other hand, examines the variation in firms' ability to raise the capital necessary for the purchase, installation, and testing of emission control equipment.

The capital availability analysis also serves three other purposes. First, it provides information for evaluating the appropriateness of the selected discount rate as a proxy for the marginal cost of capital of the industry; implications for bias in the partial equilibrium analysis follow. Second, it provides information on potential variation in capital costs across firms. Third, it provides measures of the potential impacts of the NESHAP on the profitability of affected firms.

Evaluation of Impacts on Capital Availability

For each firm included in the capital availability analysis, the impact of the regulatory alternatives on the following two measures is evaluated:

- Net income/assets.
- Long-term debt/long-term debt and equity.

The ratio of net income to assets is a measure of return on investment. Compliance costs may reduce this ratio to the extent that net income falls (because of higher operating costs) and assets increase (because of investments in emission control equipment).

The ratio of long-term debt to long-term debt plus equity is a measure of risk perceived by potential investors. Other things being the same, a firm with a high debt-equity ratio is likely to be perceived as being more risky, and as a result, may encounter difficulty in raising capital. This ratio will increase if affected firms purchase emission control equipment by issuing long-term debt.

Baseline Values for Capital Availability Analysis

Baseline values for net income and net income/assets are derived by averaging data that are available between 1993 and 1995. Data from several years are employed to reduce distortions caused by year-to-year fluctuations. Since changes in the long-term debt ratio represent actual structural changes, data for the most recent year available are used.

Post-Control Values for Capital Availability Analysis

Post-control values for the two measures identified above are computed to evaluate the ability of affected firms to raise required capital. The post control values are computed as follows:

- Post-control net income — pre-control before-tax net income minus annualized compliance costs.
- Post-control return on assets — post-control net income divided by the sum of pre-control assets plus investments in emission control equipment.
- Post-control long-term debt ratio — the sum of pre-control long-term debt and investments in emission control equipment divided by the sum of pre-control long-term debt, equity, and investments in emission control equipment.

Note that we adopt a worst-case assumption that net income does not increase because of higher post-control prices. We also adopt a worst-case assumption for the debt ratio in that we assume that the total investment in emission control equipment is debt-financed. We relax this assumption in the sensitivity analysis reported in Appendix D.

Limitations of the Capital-Availability Analysis

The first limitation of the capital availability analysis is that future baseline performance may deviate from past levels. The financial position of a firm during the period 1993-1995 may not be a good approximation of the company's position later during the implementation period, even in the absence of the impacts of emission control costs.

Second, a limited set of measures is used to evaluate the impact of controls. These measures reflect accounting conventions and provide only a rough approximation of the factors that will influence capital availability.

Third, financial data are not available for all firms expected to be affected by the regulatory alternatives. Financial data tend to be available for larger, publicly-held firms. These companies might not be representative of all affected firms.

EVALUATION OF SECONDARY IMPACTS

The secondary impacts that we consider in this study include:

- Employment impacts.
- Energy impacts.
- Foreign trade impacts.
- Regional impacts.

Employment Impacts

As equilibrium output in affected industry segments falls because of control costs, employment in the industry will decrease. On the other hand, operating and maintaining emission control equipment requires additional labor for some control options. Direct net employment impacts are equal to the decrease in employment due to output reductions, less the increase in employment associated with the operation and maintenance of emission control equipment.

Our estimates of the employment impacts associated with the proposed NESHAP are based on employment-output ratios and estimated changes in domestic production. Specifically, we compute changes in employment proportional to estimated changes in domestic production.[9]

Estimates of the labor hours required to operate and maintain emission control equipment are unavailable. Accordingly, the employment impacts presented in this report are overstated to the extent that potential employment gains attributable to operating and maintaining control equipment are not considered. Also, we do not include estimates of employment impacts at firms indirectly affected by the proposed NESHAP, such as those at firms selling inputs to the refining industry or substitute products.

The estimates of direct employment impacts are driven by estimates of output reductions obtained in the market analyses. Biases in these estimates will likely cause the estimates of

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[9] See Appendix B for descriptions of the data and methods used to estimate employment impacts.

employment impacts to be biased in the same direction. Accordingly, the limitations of the partial equilibrium model apply here as well.

Energy Effects

The energy effects associated with the proposed NESHAP include reduced energy consumption at petroleum refineries due to reduced output in the refining industry plus the net change in energy consumption associated with the operation of emission controls.

The method we use to estimate reduced energy consumption at petroleum refineries due to output reductions is similar to the approach employed for estimating employment impacts.[10] Specifically, we assume that changes in energy use are proportional to estimated changes in domestic production. Estimates of the net change in energy consumption due to operating emission controls are unavailable.[11]

Regional Impacts

Substantial regional or community impacts may occur if a plant that employs a significant percent of the local population or contributes importantly to the local tax base is forced to close or to reduce output because of compliance costs. Secondary employment impacts may be generated if a substantial number of plants close as a result of compliance costs. Secondary employment impacts include those suffered by employees of firms that provide inputs to the directly affected industry, employees of firms that purchase inputs from directly affected firms for end-use products, and employees of other local businesses. We evaluate these potential impacts by assessing whether plant closures are likely, and whether at-risk refineries employ a substantial portion of local and regional workforces.

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[10] See Appendix B for a more detailed description of this procedure.

[11] We view these as short-run estimates of reduced energy consumption. In the long run, resources diverted from the production of refined petroleum products will likely be directed to producing other goods and services.

A second purpose of the regional analysis is to assess the implications of modeling the petroleum refining industry as a national market instead of modeling regional markets. We conduct this assessment by constructing the following impact indicators for each regional market:

- Average annualized compliance costs per dollar of revenue.
- Marginal annualized compliance costs per dollar of revenue (i.e., compliance costs of the highest-cost refinery.

We define regions by Petroleum Administrative Defense Districts (PADDs).

CHAPTER 4

PRIMARY ECONOMIC IMPACTS AND
CAPITAL AVAILABILITY ANALYSIS

INTRODUCTION

This section presents estimates of the primary economic impacts of the proposed NESHAP on the petroleum refining industry. Primary impacts include changes in market prices and output levels, changes in the value of shipments by domestic producers, and plant closures. We also present the results of the capital availability analysis which assesses the ability of affected firms to raise capital and estimates the impacts of control costs on plant profitability.

ESTIMATES OF PRIMARY IMPACTS

As explained earlier in Section 3, we use a partial equilibrium model of the petroleum industry to estimate primary impacts. The increase in production costs resulting from the purchase and operation of emission control equipment causes an upward, vertical shift in the industry supply curve. The height of this shift is determined by the after tax-cash flow required to offset the per unit increase in production costs resulting from compliance. Because control costs vary across plants within the industry, the post-control supply curve is segmented. We assume a worst case scenario in which plants with the highest control costs (per unit of output) are marginal (highest cost) in the post-control market.

Our model accounts for the impact that the proposed NESHAP might have on foreign trade in refined petroleum products. We assume that the supply elasticities of refined products are the same in domestic and foreign markets and that higher prices in the domestic market attracts additional imports of refined products.

Table 4-1 presents the primary impacts predicted by the partial equilibrium analysis for the petroleum refining industry. For example, we estimate that the implementation of the NESHAP will result in a $0.07 (0.24 percent) increase in the average price of refined petroleum and an annual reduction in domestic production of 8.7 million barrels (0.17 percent of baseline production). Although the industry faces compliance costs resulting from the rule, the analysis shows that the NESHAP will cause the annual value of domestic shipments to increase by $109.27 million (0.07 percent). The value of shipments increases because the price increase more than offsets the reduction in output.

Table 4-1

ESTIMATED PRIMARY IMPACTS
ON THE PETROLEUM REFINING INDUSTRY

	Estimated Impact
Price Change	
$/bbl[a]	0.07
percent	0.24
Annual Change in Domestic Output	
million barrels/yr.	-8.71
percent	-0.17
Annual Change in Value of Shipments	
$million[a]	109.27
percent	0.07
Plant Closures[b]	0

[a] 1996 dollars.
[b] Ranges of predicted plant closures reflect alternative assumptions about different control technologies adopted by model plants.

We emphasize that many of the assumptions we adopt in our analysis are likely to cause us to overstate predicted economic impacts. First, we assume that the plant with the highest per unit emission control costs also is the least efficient in that it has the highest baseline per unit production costs. Second, we assume a national market, but regional trade barriers might afford some protection for some refineries.

The estimated primary impacts reported above depend on a set of parameters used in the partial equilibrium model of the petroleum refining industry. One of the parameters, the elasticity of demand, measures how sensitive buyers are to price changes. A second parameter, the elasticity of supply, measures how sensitive suppliers, or producers, are to price changes.

The estimated impacts reported above in Table 4-1 are based on a mid-point demand elasticity estimate of −0.65 and a supply elasticity estimate of 1.24. In Appendix A, we report the results of analyses that show the sensitivity of the estimated impacts to changes in these elasticity estimates. The “low” elasticity case adopts a demand elasticity of −0.50 and a supply elasticity of 1.00. The “high” elasticity case reported in Appendix A uses a demand elasticity of −0.79 and a supply elasticity of 1.50. The sensitivity analyses show that the estimated primary impacts are relatively insensitive to reasonable ranges of demand and supply elasticity estimates.

CAPITAL AVAILABILITY ANALYSIS

The capital availability analysis involves examining pre- and post-control values of selected financial ratios. These ratios include net income divided by assets and long term debt divided by the sum of long term debt and equity. In order to reduce the effects of year-to-year fluctuations in net income, we used a three-year average (1993 through 1995) of net income over assets as the baseline. Changes in the long term debt ratio represent structural changes and so are not subject to the same cyclical fluctuations. We used long term debt ratios from 1995 as the baseline.

As explained in Section 3, these financial statistics lend insight into the ability of affected firms to raise the capital needed to acquire emission controls. They also provide estimates of the changes in profitability which would arise from the implementation of the NESHAP.

To calculate the post-control ratio of net income to assets, we subtracted annualized control costs from pre-control net income, and added capital control costs to pre-control assets. To calculate the post-control long term debt ratio, we added capital control costs to pre-control long term debt, both in the numerator and denominator of this ratio. Note that the post-control debt ratios reflect a worst-case assumption that affected firms are required to finance emission controls entirely through debt. In Appendix D, we report the results of a sensitivity analysis in which we assume that only 70 percent of investments in emission controls are financed through debt.

Table 4-2 shows the results of the capital availability analyses conducted for the proposed NESHAP. In general, the NESHAP has a small effect on the ratio of net income to assets for affected companies included in the analysis. The largest declines in this ratio are in the neighborhood of about one-tenth of a percentage point. The effects of the NESHAP on the long-term debt ratios are also small; the largest increase is about one-tenth of a percentage point.

All of the companies included in Table 4-2 are publicly held corporations with relatively large financial resources. As a result, emission controls costs, which are small relative to their overall financial resources, have no significant impacts on the firms' financial ratios. Accordingly, we conclude that the companies that we analyzed will not find it difficult to raise the capital necessary to purchase and install the required emission controls. We note, however, that publicly held firms for which financial data are available might not be representative of privately held firms in the industry. However, because compliance costs are small relative to the estimated value of output for even the smaller firms (less than one cent per dollar of output), it is unlikely that they will face difficulty raising the capital required for investments in emission controls.

Table 4-2

IMPACTS ON FINANCIAL RATIOS OF SELECTED FIRMS

Firm Name	Net Income / Assets[a] (%)		LTD / (LTD + E)[b] (%)	
	Pre-Control	Post-Control	Pre-Control	Post-Control
Amerada Hess Corp.	3.02	3.02	48.68	48.69
Amoco Oil Co.	6.24	6.24	21.06	21.10
Ashland Petroleum Co.	2.10	2.07	52.48	52.58
Chevron USA Inc.	3.76	3.75	24.52	24.53
Coastal	1.96	1.96	58.59	58.59
Conoco Inc.	5.91	5.90	40.23	40.24
Diamond Shamrock Corp.	2.72	2.63	60.52	60.61
Exxon Co. USA	34.63	34.56	16.13	16.16
Fina Oil & Chemical Co.	3.70	3.64	31.05	31.22
Marathon Oil Co.	1.36	1.33	53.97	54.04
Mobil Oil Corp.	4.45	4.44	20.50	20.56
Murphy Oil	4.97	4.94	15.67	15.78
Phillips 66 Co.	3.45	3.42	49.28	49.35
Shell Oil Co.	3.49	3.48	8.59	8.62
Sun Co.	2.99	2.99	34.33	34.33
Texaco Refining & Marketing Inc.	3.34	3.33	36.63	36.66
Unocal Corp.	2.15	2.15	55.79	55.80

Note: [a] Average ratio, 1993 through 1995.
[b] 1995 ratio of long-term debt to long-term debt plus equity.

Source: Pre-control ratios, Moody's Industrial Manual, (1995).

LIMITATIONS

Several qualifications of the results presented in this section need to be made. We assume a single national market for refined petroleum products in the partial equilibrium analysis. However, there may be some regional trade barriers which would protect producers. Furthermore, the analysis assumes that plants with the highest per unit emission control costs are marginal post-control. This assumption will cause the impacts presented above to be overstated since market impacts are determined by the costs of marginal plants. Some plants may find that the price increase resulting from regulations make it profitable to expand production. This would occur if a firm found its post-control incremental unit costs to be smaller than the post-control market prices. Expansion by these firms would result in smaller decreases in output and smaller increases in prices than predicted by our analysis. For example, some refineries are not expected to incur compliance costs as a result of the NESHAP. These plants will benefit from price increases without incurring of compliance costs.

We have also noted that the estimated primary impacts depend on the parameters of the partial equilibrium model. The results of the sensitivity analyses presented in Appendix A, which are based on alternative estimates of demand and supply elasticities, show impacts similar to those reported above. In Appendix D, we report the results of a sensitivity analysis which alters our worst-case assumption that affected firms finance investments in emission control entirely through debt. These analyses show slightly smaller impacts on the financial ratios of affected firms.

SUMMARY

We estimate that average refined product prices will increase by about 0.24 percent and domestic output will fall by about 0.17 percent. However, the value of refined product shipments will increase by about 0.07 percent because of higher prices. Our model predicts no refinery are at risk of closure, but we emphasize that this prediction is partially the result of worst-case assumptions adopted in our analysis. Finally, because compliance costs are small relative to the financial resources of the affected producers examined, they should not find it difficult to raise the capital necessary to finance the purchase and installation of emission controls.

CHAPTER 5

SECONDARY ECONOMIC IMPACTS

INTRODUCTION

This section presents estimates of the secondary economic impacts that would result from the implementation of the proposed NESHAP. Secondary impacts include changes in employment, energy use, foreign trade and regional impacts.

LABOR IMPACTS

The estimated labor impacts associated with the NESHAP are based on the results of the partial equilibrium analysis of the petroleum refining industry. These impacts depend primarily on the estimates of reduction in domestic production reported earlier in Section 4.[1] Note that changes in employment due to the operation and maintenance of control equipment have been omitted from this analysis due to lack of data. Also, the estimated employment impacts reported below do not include potential employment gains in industries which produce substitute commodities that might benefit from reduced production in the petroleum refining industry. Thus, the changes in employment estimated in this section reflect only the direct employment losses due to reductions in domestic production of refined petroleum.

Table 5-1 presents estimates of employment losses for the industry. We estimate that the proposed NESHAP will reduce employment in the petroleum refining industry by about 136 jobs. This estimate is about 0.17 percent of baseline employment.

As noted above, our estimates of employment impacts are driven by the estimates of output reductions and plant closures reported in Section 4. This means that the estimated

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[1] More specifically, we estimate employment impacts by assuming that labor use per unit of output will remain constant when the quantity of output changes. Production worker hours per dollar of output was calculated from 1995 Annual Survey of Manufactures. See Appendix B for a more detailed discussion.

employment impacts reflect the worst-case assumptions adopted in the analysis for the same reasons discussed earlier in Section 4.

Table 5-1

ESTIMATED EMPLOYMENT REDUCTIONS

	Estimated Loss
Jobs	136
Percent Reduction	0.17

Note: Estimates do not include potential employment gains due to operating and maintaining emission controls.

ENERGY USE IMPACTS

The approach we employ to estimate reductions in energy use is similar to the approach employed to estimate labor impacts. Again, these impacts depend primarily on the estimated reductions in domestic output reported earlier in Section 4. Note that the changes reported below do not account for the potential increases in energy use due to operating and maintaining emission control equipment or possible changes in production times for reformulated foam products. This omission is due to lack of data.

Table 5-2 presents changes in the use of energy for the industry. We estimate that the use of energy by the petroleum industry will fall by about 7.47 million dollars, which is about 0.2 percent of baseline energy use. Again, this estimate reflects the worst case assumptions adopted in our analysis.

FOREIGN TRADE IMPACTS

Other factors being the same, the implementation of the NESHAP will raise the production costs of domestic refineries relative to foreign producers. This will cause U.S. imports to increase and U.S. exports to decrease. Table 5-3 reports estimates of the trade impacts predicted by our partial equilibrium analysis. We estimate that net exports (exports minus imports) will fall by about 1.32 million barrels (0.8 percent) annually.

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Table 5-2

ESTIMATED ENERGY USE REDUCTIONS

Industry Segment	MACT Floor
Millions of 1996 $	7.47
Percent Reduction	0.20

Note: Estimates do not include potential employment gains due to operating and maintaining emission controls.

Table 5-3

ESTIMATED TRADE IMPACTS

Annual Change in Net Exports	
Barrels (millions)	−1.32
Percent of Baseline Volume	0.80

REGIONAL IMPACTS

We do not anticipate any significant regional impacts as a result of the implementation of the proposed NESHAP. Under the worst-case assumptions underlying our analysis, we estimate employment losses totaling 136 jobs, or only 0.17 percent of the total nationwide refinery employment estimate.

We have also conducted a regional analysis to assess the implications of assuming a single national market in our partial equilibrium model. The primary issue is whether the NESHAP will affect regional trade flows enough to cause us to alter the conclusions drawn from the national model. Table 5-4 reports compliance costs relative to revenues for affected refineries across five regions defined by the Petroleum Administrative Defense Districts

(PADDs).[2] There is regional variation in average annualized compliance costs per dollar of output, but these are very small for all five regions (a fraction of a cent per dollar of output).

Table 5-4

ECONOMIC IMPACT INDICATORS BY PADD[a]

Impact Indicator	PADD A	PADD B	PADD C	PADD D	PADD E	Industry
Average Compliance Costs per $ of Output[b]	0.0004	0.0010	0.0005	0.0002	0.0002	0.0004
Marginal Compliance Costs per $ of Output[b]	0.0076	0.0045	0.0026	0.0022	0.0017	0.0076

Notes: [a] We have coded PADDs to protect confidential business information.
[b] Compliance costs annualized at a 10 percent real discount rate assuming 10 and 20 year equipment lives.

Marginal compliance costs are the key indicator of potential regional trade flows.[3] We compute these as the annualized compliance costs per dollar of output for the highest cost firms in each of the five regions. The marginal compliance costs for PADD A are relatively small, but substantially higher than those of other regions. These costs, however, reflect the situation facing the one refinery predicted to close in our partial equilibrium model. If this closure occurs, we would expect some refined products to flow into PADD A from other regions. However, these regional flows would be small since total industry-wide production is expected to fall by only 0.17 percent.[4]

In summary, one plant in PADD A has the highest annualized compliance costs per dollar of output. If this plant closes, some regional flows of refined products into PADD A from other regions would occur. However, these flows would be very small relative to total domestic production. Also, because the regional differences in average and marginal compliance costs are small relative to refineries revenues, we do not expect the proposed NESHAP to cause substantial changes in the regional prices of refined petroleum products.

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[2] We have coded the PADDs in Table 5-4 to protect confidential business information.

[3] Recall that the costs of the marginal or highest cost producers drive market impacts.

[4] See Table 4-1.

LIMITATIONS

Our estimates of the secondary impacts associated with the NESHAP are based on changes in market equilibrium predicted by the partial equilibrium model of the petroleum refining industry. Accordingly, the caveats we discussed earlier in Section 4 for the primary impacts apply as well to our estimates of secondary impacts.

As noted earlier, the estimates of employment impacts do not include potential employment gains due to operating and maintaining emission control equipment or employment gains in the manufacturing of substitute products. Similarly, the estimates we report exclude potential indirect employment losses in industries that supply inputs to the petroleum refining industry and employment gains in industries producing substitute products. In short, the reported estimates of employment impacts include only direct job losses in the petroleum refining industry.

SUMMARY

The estimated secondary economic impacts of the proposed NESHAP are generally small because only small reductions in industry output are expected for the refining industry. We estimated reductions in employment trade and energy use of about 0.2 percent. Significant impacts on regional economies are unlikely.

CHAPTER 6

REGULATORY FLEXIBILITY ANALYSIS: METHODOLOGY AND RESULTS

This section describes our analysis of the impacts of the proposed NESHAP on small businesses in the petroleum refining industry. First, we provide background information on small business analytical requirements and define small businesses in industry. Next, we assess the impacts of the NESHAP on small businesses operating refineries. Based on EPA's interim guidance for conducting a Regulatory Flexibility Analysis, we conclude that the NESHAP will not have a significant impact on a substantial number of small businesses.

METHODOLOGY: SMALL BUSINESS ANALYTICAL REQUIREMENTS

The Regulatory Flexibility Act of 1980 (RFA), as amended by the Small Business Regulatory Enforcement Act of 1966 (SBREFA), requires EPA to determine whether proposed regulations will have a significant economic impact on a substantial number of small entities (SISNOSE). Small entities include small businesses, small governments and small organizations (e.g., non-profit organizations). The Small Business Administration (SBA) defines businesses by Standard Industrial Classification (SIC) codes and typically defines business sizes by measures such as employment or sales. SBA classifies petroleum refineries as small if corporate-wide employment is less than 1,500 *and* daily crude processing capacity is less than 75,000 b/cd.[1]

The RFA requires EPA (and other federal agencies) to prepare an initial regulatory flexibility analysis (IRFA) for a proposed rule and a final regulatory flexibility analysis (FRFA) for a final rule unless EPA certifies that the rule will not have an significant economic impact on a substantial number of small businesses. However, since the RFA defines neither "significant economic impact" nor "substantial number," agencies have discretion in defining these terms. EPA has issued interim guidance measuring economic impacts and defining substantial numbers

[1] See Federal Register (61 FR 3175), January 31, 1996 for SBA size standards.

of small entities.[2] EPA's guidance recommends measuring economic impacts in any one of these three ways:

- Annualized compliance costs as a percentage of sales.
- Debt-finances capital costs relative to cash flow.
- Annualized compliance costs as a percentage of before-tax profits.

Further, the guidance defines "substantial number" in terms of the percentage and absolute number of small entities affected by the regulation.

Table 6-1 summarizes EPA's criteria for using quantitative information to assess small business impacts. For example, if annualized compliance costs are less than one percent of sales for all affected small entities, then the proposed NESHAP would be classified as "Category 1." EPA's interim guidance further states that for Category 1: "The Rule is presumed **not** to have a significant impact on a substantial number of small entities. . ." [3].

RESULTS: ASSESSMENT OF SMALL BUSINESS IMPACTS

A total of 19 refineries considered in our analysis are operated by 16 small businesses.[4] Two of these refineries operated by 2 different firms are expected to incur compliance costs and the remaining 17 refineries are not expected to incur compliance cost as a result of the proposed NESHAP.

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[2] See EPA (1997a). SBA has approved EPA's guidance on Regulatory Flexibility Analyses that adhere to SBREFA.

[3] EPA (1997a), p. 1-14.

[4] Small businesses operating petroleum refineries are identified in NPRA (1997). The NPRA survey identifies a total of 22 small businesses in the refining industry. Of these, 16 are included in our analysis and the characteristics of the remaining 6 firms are unknown. See Mathtech (1997).

Table 6-1

SUMMARY OF QUANTITATIVE INFORMATION USED TO IDENTIFY APPLICABLE CATEGORIES

Quantitative Criteria			Regulatory Process Category
Economic Impact Condition	Number of Small Entities Experiencing Economic Impact Condition	Number of Small Entities Experiencing Economic Impact Condition as a Percentage of All Affected Small Entities	
Less Than 1% for All affected small entities	Any Number	Any Percent	Category 1
1% or greater for one or more small entities	Fewer than 100	Any Percent	Category 1
	100 to 999	Less than 20%	Category 1
	100 to 999	20% or more	Category 2
	1000 or more	Any Percent	Category 2
3% or greater for one or more small entities	Fewer than 100	Any Percent	Category 1
	100 to 999	Less than 20%	Category 2
	100 to 999	20% or more	Category 3
	1000 or more	Any Percent	Category 3

Source: EPA (1997a).

We have computed annualized compliance costs as a percent of estimated sales revenues for each of the affected small businesses.[5] Annualized compliance costs are less than one percent of estimated sales revenues for all affected small businesses.[6] Based on the criteria in Table 6-1, we classify the proposed NESHAP as Category 1. As noted above, EPA's interim guidance states that a Category 1 rule will not have a significant economic impact on a substantial number of small entities.

We note that there are limitations to our analysis of small business impacts. Compliance costs relative to sales revenues is only an indicator of potential economic impacts and additional data and further analysis are required to estimate fully the impacts of the NESHAP on small refiners. In particular, data of profit margins available to cover compliance costs would be

[5] Compliance costs annualized at a 10 percent real discount rate assuming a 10-year equipment life.

[6] Annualized compliance costs are less than 0.20 percent of estimated sales revenues for all affected small businesses.

valuable to assess small business impacts. The fact that all small refiners fall in the range of insignificance according to the SBREFA interim guidance does not mean that significant impacts will not occur. EPA's interim guidance acknowledges this possibility and allows for further analysis if other information suggests the possibility of significant adverse impacts.

CHAPTER 7

SOCIAL COSTS AND ECONOMIC EFFICIENCY

Estimates of the social (economic) costs associated with the implementation of the proposed NESHAP for the petroleum refining industry are presented below in this section of the report.

ECONOMIC COSTS OF EMISSION CONTROLS: CONCEPTUAL ISSUES

Air quality regulations affect society's economic well-being by causing a reallocation of productive resources within the economy. Specifically, resources are allocated to the production of cleaner air and away from other goods and services that could otherwise be produced. Accordingly, the social, or economic, costs of compliance can be measured as the value that society places on those goods and services not produced as a result of resources being diverted to the production of improved air quality. According to economic theory, the conceptually correct valuation of these costs requires the identification of society's willingness to be compensated for these foregone consumption opportunities that would otherwise be available.[1,2]

In the discussion that follows, we distinguish between compliance costs and the social or economic costs associated with the NESHAP. The former are measured simply as the annualized capital and annual operating, maintenance, monitoring and record-keeping costs under the assumption that all affected plants install controls. As noted above, economic costs reflect society's willingness to be compensated for foregone consumption opportunities.

Estimates of emission control costs will correspond to the conceptually correct measure of economic costs only if the following conditions hold:

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[1] Willingness to be compensated is the appropriate measure of economic costs, given the convention of measuring benefits as willingness to pay. Under this convention, the potential to compensate those members of society bearing the costs associated with a policy change is compared with the potential willingness of gainers to pay for benefits. See Mishan (1971).

[2] These costs are often referred to as "Social Costs," as well as economic costs.

- Marginal plants affected by an alternative standard must be able to pass forward all compliance costs to buyers through price mark-ups without reducing the quantity of goods and services demanded in the market.

- The prices of emission control resources (e.g., pollution control equipment, alternative materials, and labor) used to estimate costs must correspond to the prices that would prevail if these factors were sold in competitive markets.

- The discount rate employed to compute the present value of future costs must correspond to the appropriate social discount rate.

- Emission controls do not affect the prices of goods imported to the domestic economy.

Market Adjustments

A plant is marginal if it is among the least efficient producers in the market and, as a result, the level of its costs determine the post-control equilibrium price. A marginal plant can pass on to buyers the full burden of emission control costs only if demand is perfectly inelastic. Otherwise, consumers will reduce quantity demanded when faced with higher prices. If this occurs, estimated control costs will overstate the economic costs associated with a given air quality standard.

The compliance costs estimates do not reflect any market adjustments that are likely to occur as affected plants and their customers respond to higher post-control production costs. As a result, the estimates of economic costs presented later in this section will differ from the emission control costs to reflect estimates of such market adjustments.

Markets for Emission Control Resources

Other things being the same, compliance costs will overstate the economic costs associated with an alternative air quality standard if the estimates are based on factor prices (e.g., emission control equipment prices and wage rates) which reflect monopoly profits earned in resource markets. Monopoly profits represent a transfer from buyers to sellers in emission control markets, but do not reflect true resource costs. We note that some of the available emission control technologies are patented. To the extent that the patents confer monopoly power, the estimates of compliance costs used in this analysis are higher than they would be if emission controls were sold in competitive markets. If this is the case, our analysis overstates true economic costs.

The Social Discount Rate

The estimates of annualized emission control costs presented earlier in this report were computed by adding the annualized estimates of capital expenditures associated with the purchase and installation of emission control equipment to estimates of annual operating and maintenance costs. The private cost of capital is appropriate for estimating how producers adjust supply prices in response to control costs.[3] In order to estimate the economic costs associated with the proposed NESHAP, an appropriate measure of the social discount rate should be used in the amortization schedule.

There is considerable debate regarding the use of alternative discounting procedures and discount rates to assess the economic benefits and costs associated with public programs.[4] The approach adopted here is a two-stage procedure recommended by Kolb and Scheraga (1990).

First, annualized costs are computed by adding annualized capital expenditures (over the expected life of emission controls) and annual operating costs. Capital expenditures are annualized using a discount rate that reflects a risk-free marginal return on investment.[5] This discount rate, which is referred to below as the social cost of capital, is intended to reflect the opportunity cost of resources displaced by investments in emissions controls. Kolb and Scheraga (1990) recommend a range of 5 to 10 percent for this rate. We adopt a midpoint value of 7.0 percent in this analysis.[6]

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[3] In other words, a discount rate reflecting the private cost of capital to affected firms should be used in analyses designed to predict market adjustments associated with emission control costs. The private cost of capital, assumed to be 10 percent in this analysis, is higher than the 7 percent social discount rate because it reflects the greater risk faced by individual procedures relative to the risk faced by society at large.

[4] See Lind, et al. (1982) for a more detailed discussion of this debate.

[5] The risk-free rate is appropriate if the NESHAP, as a program, does not add to the variance of the return on society's investment portfolio.

[6] The 7 percent discount rate is also consistent with recent OMB recommendations.

Second, the present value of the annualized stream of costs should be computed using a consumption rate of interest which is taken as a proxy for the social rate of time preference. This discount rate, which is referred to below as the social rate of time preference, measures society's willingness to be compensated for postponing current consumption to some future date. Kolb and Scheraga (1990) argue that the consumption rate of interest probably lies between 1 and 5 percent. We do not, however, present estimates of the present value of the costs associated with the NESHAP in this report.

The resulting estimates of the present value of the economic costs associated with the proposed NESHAP can be compared with estimates of the present value of corresponding benefits of the regulation. The social rate of time preference should be employed to discount the future stream of estimated benefits.

OTHER COSTS ASSOCIATED WITH NESHAP

It should be recognized that the estimates of costs reported later in this section do not reflect all costs that might be associated with the NESHAP. Examples of these include some administrative, monitoring, and enforcement costs (AME), and transition costs.

AME costs may be borne by directly affected firms and by different government agencies. These latter AME costs, which are likely to be incurred by state agencies and EPA regional offices, for example, are reflected neither in the estimates of compliance costs, nor in the estimates of economic costs. However, our estimates do include administrative and monitoring costs incurred by affected firms.

Transition costs are also likely to be associated with the alternative standards. Analyses described in previous sections of this report, for example, predict that some plants will close because of compliance costs. This will cause some individuals to suffer transition costs associated with temporary unemployment and affected firms to incur shutdown costs. These transition costs are not reflected in the cost estimates reported later in this section.

CHANGES IN ECONOMIC SURPLUS AS A MEASURE OF COSTS

As was noted earlier, the willingness to be compensated for foregone consumption opportunities is taken here as the appropriate measure of the costs associated with the proposed NESHAP. In this case, compensating variation is an exact measure of willingness to be compensated. In practice, however, compensating variation is difficult to measure; consequently, the change in economic surplus associated with the air quality standard is used as an approximation to compensating variation.

The degree to which a change in economic surplus coincides with compensating variation as a measure of willingness to be compensated depends on whether the surplus change is measured in an input market or a final goods market. The surplus change is an exact measure of compensating variation when it is measured in an input market, but it is an approximation when measured in a final goods market.[7]

The direction of the bias in the approximation of compensating variation when the surplus change is measured in a final goods market depends on whether affected parties realize a welfare gain or suffer a welfare loss, but in either case, the bias is likely to be small.[8] Affected firms (and their customers) will suffer a welfare loss as the result of the implementation of emission controls. In this case, the change in economic surplus will exceed compensating variation, the exact measure of willingness to be compensated.[9]

ESTIMATES OF SOCIAL COSTS

Estimates of the annualized total social, or economic, costs associated with the NESHAP are reported in Table 7-1 (for a social cost of capital equal to 7 percent). We estimate that compliance with the proposed NESHAP will result in annual costs of about $63 million (measured in 1996 dollars).

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[7] See Just, Hueth, and Schmitz (1982) for a more detailed discussion.

[8] See Willig (1974).

[9] See Appendix B for a detailed, technical description of the methods employed to compute changes in economic surplus.

Table 7-1 shows how losses in surplus are distributed among consumers, domestic producers and society at large. The latter is referred to as "residual" surplus in the tables. The loss in consumer surplus includes higher outlays for refined petroleum products plus a dead weight loss due to foregone consumption. These losses are due mostly to higher expenditures on refined petroleum products.

We compute the loss in producer surplus as annualized compliance costs incurred by plants remaining in operation, plus the dead weight loss in surplus due to reduced output, less increased revenue due to higher post-control prices. The estimated loss in producer surplus reported in Table 7-1 is negative, meaning that producers would realize a net gain in economic surplus. This occurs because higher post-control market prices more than offset compliance costs.

Surplus losses to society at large are computed as "residual" adjustments to account for differences in private and social discount rates and transfer effects of taxes. The estimates of changes in producer surplus reflect a 10 percent real private rate on emission control capital costs. Recall that social costs are discounted at a 7 percent real rate.[10]

[10] Since the loss in producer surplus measures the burden of the alternative borne by producers, we calculate it using the private cost of capital.

Table 7-1

PETROLEUM REFINING INDUSTRY ESTIMATES
OF ANNUALIZED ECONOMIC COSTS

Loss in Consumer Surplus (MM$96)	Loss in Producer Surplus (MM$96)	Loss in Residual Surplus (MM$96)	Loss in Total Surplus (MM$96)
393.02	−245.77	−83.94	63.31

We note that the distribution of economic costs between consumers and domestic producers depends, in part, on the way we have constructed the post-control supply curve. As explained earlier, we have assumed that plants with the highest emission control costs (per unit of output) are marginal in the post-control market. This assumption is worst case in that it results in large increases in prices (relative to an alternative assumption that plants with high control costs are not marginal), thus shifting the cost burden to consumers and away from plants that continue to operate in the post-control market. Any alternative construction of the post-control supply curve would result in smaller price increases and shift a larger share of economic costs away from consumers to domestic producers. In other words, smaller price increases would reduce the economic rent realized by domestic producers in the post-control market.

Earlier, we explained that economic costs differ from compliance costs. Recall that the latter are computed simply as annualized capital costs plus annual operating and maintenance, monitoring and record-keeping costs, assuming that all plants comply with the NESHAP. Annualized compliance costs were estimated to be $53.52 million 1996 dollars. This estimate is lower than the economic costs reported in Table 7-1. Economic costs are higher than compliance costs because the former includes the surplus loss to the U.S. economy associated with higher expenditures on imports.

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APPENDIX A

SENSITIVITY ANALYSES: DEMAND AND SUPPLY ELASTICITIES

INTRODUCTION

This appendix presents the results of sensitivity analyses that explore the degree to which the results presented earlier in this report are sensitive to estimates of demand and supply elasticities.

SUPPLY AND DEMAND ELASTICITY

The "base case" results presented earlier in this report are based on a demand elasticity of −0.65 and a supply elasticity of 1.24 for refined petroleum products. Below, we report results for "low" and "high" elasticity cases. These alternative cases use the following elasticities values:

- Low demand elasticity: −0.50.
- Low supply elasticity: 1.00.
- High demand elasticity: −0.79
- High supply elasticity: 1.50.

The greater the elasticity of demand and supply (in absolute value), the greater the change in market clearing quantity in response to a given change in price. Therefore, we expect that when we use higher demand and supply elasticities in the partial equilibrium analysis, the reduction in market output will be greater than in the base case. Similarly, when we use lower elasticities, we expect the change in market quantity to be smaller, relative to the base case.

Table A-1 presents estimates of the primary impacts associated with the low, high and base elasticity cases. Under the base case elaticity estimates, one plant is predicted to close. This result is unchanged using the low elasticity estimates, but increases to two with the high elasticity estimate. The impacts on output are smaller relative to the base case in the low elasticity case and higher in the high elasticity case, as would be expected. It should be noted, as with the rest of the analyses, these predictions are based on the worst case scenario. Thus the effects predicted here are likely to be overstated.

Table A-1

SENSITIVITY ANALYSIS: ESTIMATED PRIMARY IMPACTS ON THE PETROLEUM REFINING INDUSTRY UNDER ALTERNATIVE ELASTICITY ESTIMATES

Elasticity	Price Change (%)	Change in Market Output (%)	Change in the Value of Shipments		Plant Closures
			(%)	(MM$96)	
Low	0.28	-0.18	0.13	222.38	0
High	0.21	-0.23	0.03	27.83	0
Base	0.24	-0.20	0.07	109.27	0

APPENDIX B

TECHNICAL DESCRIPTION OF ANALYTICAL METHODS

This technical appendix provides detailed descriptions of the analytical methods employed to conduct the following analyses:

- Partial equilibrium analysis (i.e., computing post-control price, output and trade impacts).
- Estimating changes in economic surplus.
- Labor and energy impacts.
- Capital availability.

We also present the baseline values used in the partial equilibrium analysis.

PARTIAL EQUILIBRIUM ANALYSIS

The partial equilibrium analysis requires the completion of four tasks. These tasks are:

- Specify market demand and supply.
- Estimate the post-control shift in market supply.
- Compute the impact on market quantity.
- Compute the impact on market price.
- Predict plant closures.

The following description of the partial equilibrium model is fully general in that it includes a foreign sector.

Market Demand and Supply

Baseline or pre-control equilibrium in a market is given by:

$$Q_d = \alpha P^{\varepsilon} \quad \text{(B.1)}$$

$$Qds = \beta P^{\gamma} \quad \text{(B.2)}$$

$$Qfs = \rho P^{\gamma} \quad \text{(B.3)}$$

$$Q_d = Qds + Qfs = Q \quad \text{(B.4)}$$

where, Q = output;

P = price;

ε = demand elasticity;

γ = supply elasticity;

α, β and ρ are constants;

Subscripts d and s reference demand and supply, respectively; and,

Superscripts d and f reference domestic and foreign supply, respectively.

The constants α, β and ρ are computed such that the baseline equilibrium price is normalized to one. Note that the market specification above assumes that domestic and foreign supply elasticities are the same.

Market Supply Shifts

Supply price for a model plant will increase by an amount just sufficient to equate the net present value of the investment and operation of the control equipment to zero. Specifically,

(B.5)

~~~~~{[(func C cdot` func Q)~ - ~ (func V + func D)`](1 - func t) + func D} over func S~ =~ func k

where C is the change in the supply price;
~~~~~

Q is output;

V is a measure of annual operating and maintenance control costs.
t is the marginal corporate income tax rate;

S is the capital recovery factor;

D is annual depreciation (we assume straight-line depreciation);

k is the investment cost of emissions controls.

Solving for C yields the following expression:

(B.6)

FUNC{~~~~~~~~~~C~=~{kS-D} over {Q(1-t)}~+~{V+D} over Q}

Estimates of k and V were obtained from EPA (1991). The variables, D, I, and S are computed as follows:

$$D = k/T \qquad \text{(B.7)}$$

and

$$S = r(1+r)^T/((1+r)^T-1) \qquad \text{(B.8)}$$

where r is the discount rate or cost of capital faced by producers;

T is the life of emission control equipment.

Solving for P in Equation (B.2) yields the following expression for the baseline inverse market supply function for domestic producers.

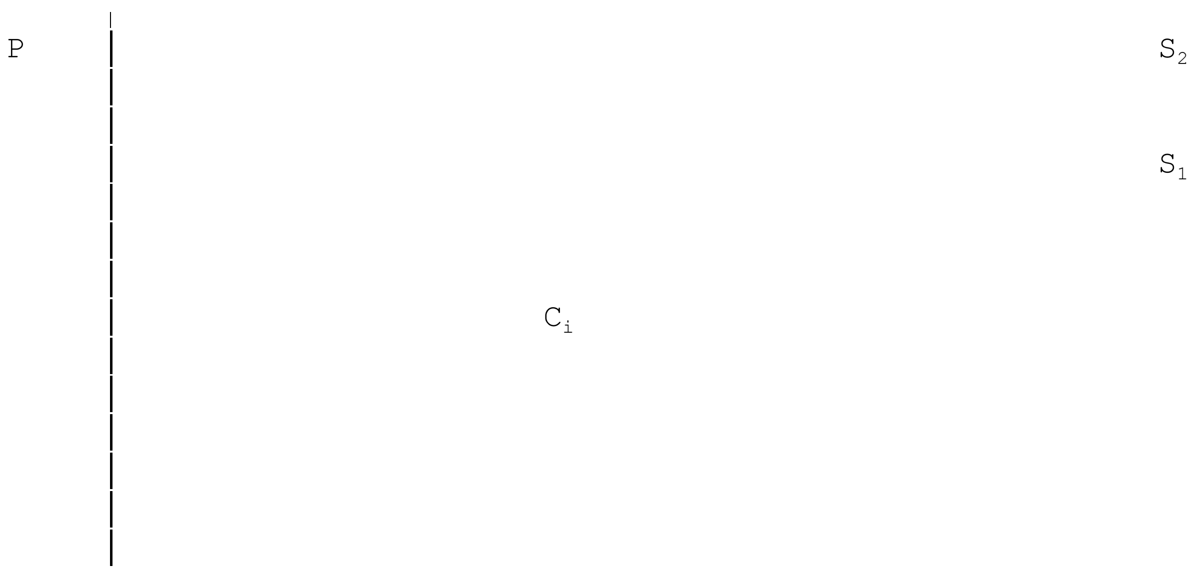
$$P = (Qds/\beta)^{1/\gamma} \qquad \text{(B.9)}$$

Emission control costs will raise the supply price of the i^{th} model plant by C_i (as computed in Equation (B.6)). The aggregate domestic market supply curve, however, does not identify the supply price for individual plants. Accordingly, we adopt the worst-case assumption that model plants with the highest after-tax per unit control costs are marginal in the post-control market. Specifically, we write the post-control supply function as

$$P \quad = \quad (Qds/\beta)^{1/\gamma} + C(C_i,q_i) \qquad \text{(B.10)}$$

where q_i is the total output of all model plants of type i.

The function $C(C_i,q_i)$ shifts segments of the pre-control domestic supply curve vertically by C_i. The width or horizontal distance of each segment is q_i. The resulting segmented post-control domestic supply curve is illustrated in Figure B-1 as S_2, compared with pre-control supply S_1.[1]



[1] The supply curves in Figure B-1 are drawn as linear functions for ease of exposition. Because the supply curves are specified as Cobb-Douglas, they are log-linear.

Qds

q_i

Impact on Market Price and Quantity

The impacts of the alternative standards on market output are estimated by solving for post-control market equilibrium and then comparing that output level, Q_2, to the pre-control output level, Q_1. Because post-control domestic supply is segmented, a special iterative algorithm was developed to solve for post-control market equilibrium. The algorithm first searches for the segment in the post-control supply function at which equilibrium occurs and then solves for the post-control market price that clears the market.

Since the market clearing price occurs where demand equals post-control domestic supply plus foreign supply, the algorithm simultaneously solves for the following post-control variables.

- Equilibrium market price.
- Equilibrium market quantity.

We assess the market impacts of control costs by comparing baseline values to post-control values for each of the variables listed above.

Figure B-1.Domestic Market Supply Shift Due to Emission Control Costs

We also report the change in the dollar value of shipments by domestic producers. This value, ΔVS, is given by

FUNC{~~~~~DELTA VS~=~P sub 2 cdot` Q sub {s sub 2} sup d ~-~ P sub 1 Q sub {s sub 1} sup d}

(B.11)

where P_1 and P_2 are, respectively, pre- and post-control market equilibrium prices.

Plant Closures

We predict that any plant will close if its post-control supply price is higher than the post-control equilibrium price. Post-control supply prices are computed by Equation (B.10). We round fractions of plant closures to the nearest integer.

CHANGES IN ECONOMIC SURPLUS

The shift in market equilibrium will have impacts on the economic welfare of three groups:

- Consumers.
- Producers.
- Society at large.

The procedure for estimating the welfare change for each group is presented below. The total change in economic surplus, which is taken as an approximation to economic costs, is computed as the sum of the surplus changes for the three groups.

Change in Consumer Surplus

Consumers will bear a dead weight loss associated with the reduction in output. This loss represents the amount over the pre-control price that consumers would have been willing to pay for the eliminated output. This surplus change is given by:

FUNC{~~~~~~~~~~ smallint {phantom x} from {Q sub 2} to {Q sub 1}~(Q/alpha) sup {1/ epsilon }~ dQ~-~ P sub 1~ cdot ~(Q sub 1`-`Q sub 2)}

In addition, consumers will have to pay a higher price for post-control output. This

(B.12)

surplus change is given by:

$$(P_2 - P_1) \cdot Q_2 \tag{B.13}$$

The total impact on consumer surplus, ΔCS, is given by (B.12) plus (B.13). Specifically,

FUNC{~~~~~~~~~~DELTA CS ~=~ smallint {phantom x} from {Q sub 2} to {Q sub 1}~(Q/alpha) sup {1/epsilon}~ dQ~-~ P sub 1` Q sub 1 ~+~ P sub 2` Q sub 2}

This change, ΔCS, includes losses of surplus incurred by foreign consumers. In this report we are only concerned with domestic surplus changes. We have no method for identifying

(B.14)

the marginal consumer as foreign or domestic.

To estimate the change in domestic consumer surplus we assume that total consumer surplus is split between foreign and domestic consumers in the same proportion that sales are split between foreign and domestic consumers in the pre-control market. That is, the change in domestic consumer surplus, ΔCS_d, is:

~~~~~FUNC DELTA CS sub d `=` left [1 - `left ( `FUNC Q sub e over Q sub {s sub 1} sup d `+` FUNC Q sub {s sub 1} sup f` right)~ right]~ DELTA CS

While ΔCS is a measure of the consumer surplus change from the perspective of the world economy, ΔCS_d represents the consumer surplus change from the perspective of the

(B.15)

domestic economy.
~~~~~

Change in Producer Surplus

To examine the effect on producers, output can be divided into two components:

- Output eliminated as a result of controls.
- Remaining output of controlled plants.

The total change in producer surplus is given by the sum of the two components.

Note that post-tax measures of surplus changes are required to estimate the impacts of controls on producers' welfare. The post-tax surplus change is computed by multiplying the pre-tax surplus change by a factor of (1-t) where t is the marginal tax rate. As a result, every one dollar of post-tax loss in producer surplus will be associated with a complimentary loss of t/(1-t) dollars in tax revenues.

Output eliminated as a result of control costs causes producers to suffer a dead-weight loss in surplus analogous to the dead-weight loss in consumer surplus. The post-tax dead-weight loss is given by:
FUNC{~~~~~~~~~~~LEFT [~ P sub 1 (Q sub {s sub 1} sup d`-`Q sub {s sub 2} sup d)~-~ smallint {phantom x} from {Q sub {s sub 2} sup d} to {Q sub {s sub 1} sup d}~(Q/beta) sup {1/ gamma }~ dQ`RIGHT]~(1-t)}

Plants remaining in operation after controls realize a welfare gain of $P_2 - P_1$ on each unit of output, but incur a per unit welfare loss of C_i. Thus, the post-tax loss in producer surplus for m model plant types remaining in the market is

(B.16)

FUNC{~~~~~~~~~~~LEFT [~ (P sub 1`-`P sub 2)`Q sub {s sub 2} sup d~+~ SUM from {i = 1} to {m}~ C sub i q sub i RIGHT] ~(1-t)}

The total post-tax change in producer surplus, ΔPS, is given by the sum of (B.16) and

(B.17)

(B.17). Specifically,

FUNC{~~~~~DELTA PS ~=~ LEFT [~ P sub 1 Q sub {s sub 1} sup d`-`P sub 2 Q sub {s sub 2} sup d`-` smallint {phantom x} from {Q sub {s sub 2} sup d} to {Q sub {s sub 1} sup d}~(Q/beta) sup {1/gamma}~ dQ~+~ SUM from {i=1} to m`C sub i q sub i right ]`(1-t)}

Recall that we are interested only in domestic surplus changes. For this reason we do not include the welfare gain experienced by foreign producers due to higher prices. This procedure treats higher prices paid for imports as a dead-weight loss in consumer surplus. Higher prices

(B.18)

paid to foreign producers represent a transfer from the perspective of the world economy, but a welfare loss from the perspective of the domestic economy.

<u>Residual Effect on Society</u>

The changes in economic surplus, as measured above, must be adjusted to account for two effects which cannot be attributed specifically to consumers and producers. These two effects are caused by tax impacts and differences between private and social discounts rates.

Two adjustments for tax impacts are required. First, per unit control costs C_i, which are required to predict post-control market equilibrium, reflect after-tax control costs. The true resource costs of emissions controls, however, must be measured on a pre-tax basis. For example, if after-tax control costs exceed pre-tax control costs, C_i overstates the true resource costs of controlling emissions.

A second tax-related adjustment is required because changes in producer surplus have been reduced by a factor of (1-t) to reflect the after-tax welfare impacts of emissions control costs on affected plants. As was noted earlier, a one dollar loss in pre-tax producer surplus imposes an after-tax burden on the affected plant of (1-t) dollars. In turn, a one dollar loss in after-tax producer surplus causes a complimentary loss of t/(1-t) dollars in tax revenues.

A second adjustment is required because of the difference between private and social discount rates. The rate used to shift the supply curve reflects the private discount rate (or the marginal cost of capital to affected firms). This rate must be used to predict the market impacts associated with emission controls. The economic costs of the NESHAP, however, must be computed at a rate reflecting the social cost of capital. This rate is intended to reflect the social opportunity cost of resources displaced by investments in emission controls.[2]

The adjustment for the two tax effects and the social cost of capital, which we refer to as the residual change in surplus, ΔRS, is given by:

FUNC{~~~~~DELTA RS~=~-` SUM from {i=1} to m`(C sub i`-`pc sub i) q sub i~+~DELTA PS cdot [t/(1-t)]}

(B.19)

where pc_i = per unit cost of controls for model plant type i, computed as in (B.5) with t=0 and r=social cost of capital.

The first term on the right-hand-side of (B.20) adjusts for the difference between pre- and post-tax differences in emission control costs and for the difference between private and social discount rates. Note that these adjustments are required only on post-control output. The second term on the right-hand-side of (B.19) is the complimentary transfer of the sum of all post-tax producer surplus.

Total Economic Costs

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2 See Section 7 for a more detailed discussion of this issue.

The total economic costs, EC, is given by the sum of changes in consumer and producer surplus plus the change in residual surplus. Specifically,

$$EC = \Delta CS_d + \Delta PS + \Delta RS \qquad (B.20)$$

LABOR AND ENERGY IMPACTS

Our estimates of the labor and energy impacts associated with the alternative standards are based on input-output ratios and estimated changes in domestic production.

Labor Impacts

Labor impacts, measured as the number of jobs lost due to domestic output reductions, are computed as

~~~~~~~~~~~DELTA FUNC L~ =~ LEFT (`( FUNC Q sub {s sub 1} sup d~-~FUNC Q sub {s sub 2} sup d`)`/`FUNC Q sub {s sub 1} sup d` RIGHT ) ~ cdot` func L sub 1
where FUNC{DELTA L} is the change in employment, L_1 is the baseline industry employment and all else is as previously defined..
(B.21)

Energy Impacts

We measure the energy impacts associated with the alternative standards as the reduction in expenditures on energy inputs due to output reductions. The method we employ is similar to the procedure described above for computing labor impacts. Specifically,

~~~~~~~~~~~DELTA FUNC E~ =~ LEFT (`( FUNC Q sub {s sub 1} sup d~-~FUNC Q sub {s sub 2} sup d`)`/`FUNC Q sub {s sub 1} sup d` RIGHT ) ~ cdot` func E sub 1

(B.22)

where FUNC{DELTA E} is the change in expenditures on energy inputs, E_1 is the baseline industry expenditure on energy and all else is as previously defined.

BASELINE INPUTS

The partial equilibrium model described above requires, as inputs, data on the characteristics of affected plants and baseline values for variables and parameters that characterize the market. These include the following:

- Estimates of production levels at domestic petroleum refineries.
- Estimates of demand and supply elasticities for refined petroleum products.
- The marginal tax rate for affected firms.
- The private discount rate (marginal cost of capital for affected firms).
- An estimate of baseline industry employment.
- An estimate of baseline energy use.
- Import and export ratios for refined petroleum products.

<u>Production at Refineries</u>

Estimates of production levels at domestic refineries were derived from figures reported in the 1992 RCRA 3007 Questionnaire. This survey reports refinery specific output for the following major refined products:

- Ethane/Ethylene.
- Propane/Propylene.
- Normal Butane/Butylene.
- Isofutane.
- Motor gasoline.
- Jet fuel (kerosene type).
- Distillate fuel oil.

- Residual fuel oil.
- Asphalt and road oil.
- Petroleum coke.

Together, these major products accounted for about 94 percent of 1992 production at U.S. refineries.

Of course, the mix of the product slates at refineries may have changed from the mix reported in the 1992 survey. To account for changing product mix, we multiply the 1992 product levels reported in the survey for each refinery by the ratio of 1995 to 1992 industry-wide production levels for each of the 10 major products.[3] This results in relatively minor adjustments to the refineries' product slates since the mix of the industry-wide product slate has been relatively stable.

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[3] Industry-wide production levels for the major products are reported in DOE's Petroleum Supply Annual, 1992 and 1995.

Table B-1

PRICES OF MAJOR REFINED PETROLEUM PRODUCTS
(1996 $/bbl)

Refined Product	Price
Ethane/Ethylene[a]	9.29
Propane/Propylene[a]	14.05
Normal Butane/Butylene[a]	16.55
Isobutane[a]	20.27
Motor Gasoline[b]	36.79
Jet Fuel[b]	25.97
Distillate Fuel Oil[b]	26.93
Residual Fuel Oil[b]	18.85
Asphalt and Road Oil[a]	33.55
Petroleum Coke[a]	1.48

Notes:

[a] 1992 prices reported in DPRA (1995) adjusted to 1996 dollars using the Producer Price Index for SIC 2911 (Petroleum Refining).

[b] 1995 prices reported in the Petroleum Marketing Annual adjusted to 1996 dollars using the Producer Price Index for SIC 2911.

Next, we matched the refineries included in the survey to the current list of 164 refineries included in this analysis.[4] We were able to match about 87 percent of the current refineries to the 1992 survey. We used the following procedures to estimate production levels at the refineries that could not be matched to the survey:

- **Step 1:** Compute annual average production per barrel of atmospheric crude capacity per calendar day across all refineries matched with the survey.
- **Step 2:** Multiply the figure obtained in Step 1 by the crude capacity of each of the unmatched refineries.

Note that this procedure is tantamount to assuming that the unmatched refineries produce an average product slate mix and operate facilities at an average capacity utilization rate.

[4] See Appendix C for a list of current refineries included in this analysis.

Since we model the market for the joint slate of refined petroleum products, we require a single measure of output at domestic refineries. We construct the single output measure as the sum of the production of the major products weighted by their respective prices.[5] Table B-1 lists the prices of the 10 major refined products in 1996 dollars per barrel.

[5] Note that this output measure also provides an estimate of revenues at domestic refineries.

In the text of this report, we present estimates of several impacts in barrels of refined product. We convert output to barrels by dividing the price-weighted measure of production by the average per barrel price of the joint product slate.

Demand and Supply Elasticities

The model requires an estimate of demand elasticity for the joint slate of refined petroleum products. We compute this elasticity as an output-weighted average of estimates for specific refined products. Ranges of product specific estimates obtained from the economic literature include:[6]

- Motor gasoline: −0.55 to − 0.82.
- Jet fuel: −0.15.
- Residual fuel oil: −0.61 to −0.74.
- Distillate fuel oil: −0.50 to −0.99.
- Liquified petroleum gas: −0.60 to −1.00

The economic impacts presented in the text of this report are based on a demand elasticity of −0.65 the product-weighted average of the mid-points of the above ranges.[7] The high (−0.79) and low (−0.50) estimates used in the sensitivity analysis reported in Appendix A are the product-weighted averages of the end-points of the above ranges.

We use the supply elasticity of 1.24 reported in Pechan and Mathtech (1994) for the estimated impacts presented in the text of this report. Since this elasticity estimate is for the joint product slate, it is appropriate for use in the model. The sensitivity analysis presented in

[6] See Pechan and Mathtech (1994).

[7] The weights are industry-wide production levels for the five products taken from DOE's Petroleum Supply Annual, 1995.

Appendix A uses supply elasticities of 1.5 and 1.0, respectively, for the high and low elasticity cases.

Tax and Discount Rates

All of the estimated impacts derived from the partial equilibrium model are based on a marginal tax rate of 25 percent and a real marginal cost of capital of 10 percent. The estimates of social costs reported in Section 7 use a 10 percent marginal cost of capital to generate market impacts, but a 7 percent social discount to compute changes in economic surplus.

Baseline Employment and Energy Use

Baseline values of industry-wide employment and energy use are taken from the 1995 Annual Survey of Manufactures.

Import and Export Ratios

The import ratio is computed as the value of imports divided by the value of domestic production for the 10 major petroleum products used to construct refinery output measures. The volume of imports and domestic production (in barrels) are taken from DOE's 1995 Petroleum Supply Annual. The prices used to value imports and production are given in Table B-1. The export ratio is computed analogously using the same data sources.

Table B-2 summarizes the baseline inputs. The $31.19 per barrel price is the weighted average price of the 10 major refined products. The estimate of domestic output is the sum of the value of industry-wide production of the 10 major products.

Table B-2

SUMMARY OF BASELINE INPUTS

Variable/Parameter	Value	Units
Price (P_1)	$31.19	1996 Dollars per barrel
Domestic Output (Q^d)	155,742	Millions of 1996 dollars
Supply Elasticity (ε)	1.24	
Demand Elasticity (γ)	−0.65	
Tax Rate (t)	0.25	
Private Discount Rate (r)	0.1	
Social Discount Rate	0.07	
Labor (L_1)	70,400	Workers
Energy (E_1)	3,777	Millions of 1996 dollars
Import Ratio[1]	0.09	
Export Ratio[2]	0.05	

[1] Total imports divided by total domestic output.
[2] Total exports divided by total domestic output.

CAPITAL AVAILABILITY ANALYSIS

Pre- and post-control values of the following financial measures are compared in the capital availability analyses:

- Net income/assets.
- Long-term debt/long-term debt plus equity.

Pre-Control Financial Measures

Pre-control measures of net income and net income/assets are computed by averaging data for the period 1993 through 1995 where these data are available. The long-term debt ratio is computed from 1995 data.

Then, pre-control values are estimated by:

i) n = FUNC{smallsum from {i=1993} to 1995} $n_i/3$ (B.23)

ii) r = FUNC{smallsum from {i=1993} to 1995} $(n_i/a_i)/3$ (B.24)

iii) l = $l_{1995}/(l_{1995} + e_{1995})$ (B.25)

where n = average net income

n_i = net income in year i

r = average return on assets

a_i = assets in year i

l = long-term debt ratio

l_{1995} = long-term debt in 1995

e_{1995} = equity in 1995

Post-Control Values

To determine the impact of controls, an estimate of the cost of controls is made. In order to get an idea of the steady-state cost, an annualized cost is used. The annualized cost, AC, for a plant is:

Annualized costs and capital costs are estimated for each model plant type. For each establishment, post-control measures are given by:

FUNC{~~~~~~~~~~~pn~=~smallsum from {i=1993} to 1995` {n sub i - AC} over 3}

FUNC{~~~~~~~~~~~pr~=~smallsum from {i=1993} to 1995` {(n sub i - AC)/(a sub i + k)} over 3}
FUNC{~~~~~~~~~~~pl~=~{l sub 1995 + k} over {l sub 1995 + e sub 1995 + k}}

(B.26)

(B.27)

(B.28)

where	pn	=	post-control average net income
	AC	=	annualized cost for the company
	pr	=	post-control return on assets
	k	=	capital cost for the company
	pl	=	post-control long-term debt ratio

APPENDIX C

REFINERY COMPLIANCE COSTS

Table C-1 is a listing of the refineries used in this analysis. Included in this table are the locations, capacities and various costs associated with the proposed NESHAP. These costs include ten and twenty year capital costs, annual costs and annualized costs. Ten and twenty year capital costs refer to the costs of purchasing and installing emission control equipment with expected lives of ten and twenty years, respectively. Total annual costs are the per year costs of operating and maintaining emission control equipment and monitoring and record-keeping. Total annualized costs are computed at a 7 percent discount rate.

Table C-1

REFINERY COMPLIANCE COSTS
($1000 1996)

Facility Name	City	State	Crude Capacity (bbl/cd)	10 year TCI[a]	20 year TCI[b]	Total AOC[c]	Total TAC[d]
Coastal Mobil Refining Co.	Mobile Bay	AL	15,000	$0	$0	$0	$0
Hunt Refining Co.	Tuscaloosa	AL	43,225	23	0	62	66
Shell Oil Products Co.	Saraland	AL	76,000	97	0	59	72
ARCO Alaska Inc.	Prudhoe Bay	AK	15,000	0	0	0	0
ARCO Alaska Inc.	Kuparuk	AK	12,000	0	0	0	0
Mapco Alaska Petroleum	North Pole	AK	130,000	0	0	0	0
Petro Star Inc.	North Pole	AK	14,000	0	0	0	0
Petro Star Inc.	Valdez	AK	40,000	0	0	0	0
Tesoro Petroleum Corp.	Kenai	AK	72,000	72	0	47	60
Berry Petroleum Co.	Stephens	AR	6,700	0	0	0	0
Cross Oil & Refining Co.	Smackover	AR	6,000	0	0	0	0
Lion Oil Co.	El Dorado	AR	52,500	171	0	149	172
Anchor Refining Co.	McKitrick	CA	10,000	0	0	0	0
Atlantic Richfield Co. (ARCO)	Carson	CA	255,000	96	0	145	159
Chevron USA Products Co.	El Segundo	CA	258,000	126	0	137	154
Chevron USA Products Co.	Richmond	CA	230,000	85	0	114	126
Exxon Co. USA	Benicia	CA	128,000	732	6,434	1,143	1,843
Huntway Refining Co.	Benicia	CA	8,400	0	0	0	0
Huntway Refining Co.	Wilmington	CA	5,500	0	0	0	0
Kern Oil & Refining Co.	Bakersfield	CA	21,400	58	0	44	57
Lunday-Thagard Co.	South Gate	CA	7,000	0	0	0	0
Mobil Oil Corp.	Torrance	CA	130,000	51	0	79	86
Paramount Petroleum Corp.*	Paramount	CA	39,500	8	0	21	22
San Joaquin Refining Co., Inc.	Bakersfield	CA	18,000	0	0	0	0

Facility Name	City	State	Crude Capacity (bbl/cd)	10 year TCI[a]	20 year TCI[b]	Total AOC[c]	Total TAC[d]
Santa Maria Refining Co.	Santa Maria	CA	10,000	0	0	0	0
Shell Oil Co.*	Martinez	CA	155,200	96	0	106	120
Sunland Refining Corp.	Bakersfield	CA	15,000	8	0	21	22
Ten By Inc.	Oxnard	CA	4,500	0	0	0	0
Texaco Refining & Marketing Inc.	Wilmington	CA	91,675	2,206	0	1,096	1,379
Texaco Refining & Marketing Inc.	Bakersfield	CA	57,760	34	0	94	98
Tosco Corp.	Martinez	CA	156,000	78	0	120	131
Ultramar	Wilmington	CA	68,000	64	0	85	94
Unocal Corp.	LA	CA	118,750	82	0	105	116
Unocal Corp.	San Francisco	CA	103,645	943	0	401	528
Witco Chemical Corp. Golden Bear Division	Oildale	CA	9,785	0	0	0	0
Conoco Inc.	Commerce City	CO	57,500	62	2,524	334	581
Total Petroleum, Inc.	Denver	CO	28,000	0	11	31	33
Star Enterprise	Delaware City	DE	140,000	123	6,185	820	1,421
Citgo Petroleum Corp.	Savannah	GA	28,000	0	0	0	0
Young Refining Corp.	Douglasville	GA	6,000	0	0	0	0
BHP Hawaii Inc.	Kapolei	HI	95,000	20	0	32	35
Chevron USA Inc.	Barber's Point	HI	54,000	51	0	40	47
Cark Oil & Refining Corp.	Blue Island	IL	66,500	68	789	164	249
Clark Oil & Refining Corp.	Hartford	IL	57,000	51	809	125	209
Marathon Oil Co.	Robinson	IL	166,000	51	4,521	566	1,000
Mobil Oil Corp.	Joliet	IL	203,700	51	8,722	1,019	1,849
Shell Oil Co.	Wood River	IL	271,000	150	0	207	228
The UNO-VEN Co.	Lemont	IL	145,350	84	1,427	240	386
Amoco Oil Co.	Whiting	IN	410,000	316	0	274	318
Countrymark Cooperative, Inc.	Mt. Vernon	IN	22,000	0	21	60	63
Laketon Refining Corp.	Laketon	IN	3,990	0	0	0	0
Farmland Industries Inc.	Coffeyville	KS	110,000	61	884	155	247
National Cooperative Refinery Association	McPherson	KS	73,600	78	2,590	371	626
Texaco Refining & Marketing Inc.	El Dorado	KS	99,750	150	4,591	609	1,063
Ashland Petroleum Co.	Catlettsburg	KY	219,300	157	0	201	223
Somerset Refinery Inc.	Somerset	KY	5,500	8	0	21	22
American International Refining Inc.	Lake Charles	LA	27,600	0	0	0	0
Atlas Processing Co. Div. of Pennzoil	Shreveport	LA	46,200	616	0	210	323
Basis Petroleum, Inc.	Krotz Springs	LA	67,100	71	3,497	445	784
BP Oil Co.	Belle Chasee	LA	242,250	62	8,656	1,024	1,848
Calcasieu Refining Co.	Lake Charles	LA	14,000	0	0	0	0
Calumet Lubricants Co.	Cotton Valley	LA	8,740	0	0	0	0
Calumet Lubricants Co.	Princeton	LA	8,000	11	0	12	13
Canal Refining Co.	Church Point	LA	9,000	0	0	20	20

Facility Name	City	State	Crude Capacity (bbl/cd)	10 year TCI[a]	20 year TCI[b]	Total AOC[c]	Total TAC[d]
Cit-Con Oil Corp.	Lake Charles	LA	0	0	0	0	0
Citgo Petroleum Corp.	Lake Charles	LA	304,000	714	0	500	595
Conoco Inc.	Westlake	LA	226,000	74	0	102	113
Exxon Co.	Baton Rouge	LA	432,000	2,098	0	1,358	1,627
Marathon Oil Co.	Garyville	LA	225,000	97	0	102	115
Mobil Oil Corp.	Chalmette	LA	176,400	84	0	120	132
Murphy Oil USA Inc.	Meraux	LA	95,000	68	1,063	199	309
Placid Refining Inc.	Port Allen	LA	48,000	62	0	71	80
Shell Chemical Co.	St. Rose	LA	40,000	0	0	0	0
Shell Oil Co.	Norco	LA	21,800	56	0	79	87
Star Enterprise	Convent	LA	230,000	51	9,854	1,147	2,083
Lakeside Refining Co.	Kalamazoo	MI	5,600	8	0	21	22
Marathon Oil Co.	Detroit	MI	70,000	51	861	150	239
Total Petroleum Inc.	Alma	MI	45,600	107	0	84	99
Ashland Petroleum Co.	St. Paul Park	MN	69,000	813	2,799	908	1,280
Koch Refining Co.	Rosemount	MN	286,000	179	0	171	198
Chevron USA Inc.	Pascagoula	MS	295,000	2,109	0	1,598	1,869
Ergon Refining Inc.	Vicksburg	MS	25,000	0	0	0	0
Southland Oil Co.	Lumberton	MS	5,800	0	0	0	0
Southland Oil Co.	Sandersville	MS	11,000	0	0	0	0
Cenex	Laurel	MT	41,450	233	741	256	376
Conoco Inc.	Billings	MT	49,400	59	639	127	195
Exxon Co.	Billings	MT	46,000	51	2,607	332	585
Montana Refining Co.	Great Falls	MT	7,000	0	0	20	20
Petro Source Refining Partners	Eagle Springs	NV	7,000	0	0	0	0
Amerada-Hess Corp.	Port Reading	NJ	0	51	1,468	199	345
Chevron USA Inc.	Perth Amboy	NJ	80,000	0	0	0	0
Citgo Asphalt Refining Co.	Paulsboro	NJ	80,000	0	0	0	0
Coastal Eagle Point Oil Co.	Westville	NJ	125,000	103	0	69	84
Mobil Oil Corp.	Paulsboro	NJ	149,000	76	0	105	116
Tosco Refining Co.	Linden	NJ	240,000	110	0	74	91
Giant Refining Co.	Bloomfield	NM	16,800	50	0	37	44
Giant Refining Co.	Gallup	NM	20,800	0	11	31	33
Navajo Refining Co.	Artesia	NM	60,000	98	3,098	460	766
Amoco Oil Co.	Mandan	ND	58,000	827	2,998	975	1,370
Ashland Petroleum Co.	Canton	OH	65,900	78	3,768	503	870
BP Oil Co.	Lima	OH	161,500	131	0	91	110
BP Oil Co.	Toledo	OH	147,250	161	7,233	911	1,617
Sun Refining & Marketing Co.	Toledo	OH	125,000	62	0	91	99
Conoco Inc.	Ponca City	OK	155,000	62	0	91	99
Gary-Williams Energy Corp.	Wynnewood	OK	43,000	72	2,981	414	706
Sinclair Oil Corp.	Tulsa	OK	50,000	100	2,830	374	655
Sun Refining & Marketing Co.	Tulsa	OK	85,000	0	0	20	20
Total Petroleum Inc.	Ardmore	OK	68,000	79	3,622	483	836
Chevron USA Inc.	Portland	OR	0	0	0	0	0
Pennzoil Products Co.	Rouseville	PA	15,700	8	0	21	22

Facility Name	City	State	Crude Capacity (bbl/cd)	10 year TCI[a]	20 year TCI[b]	Total AOC[c]	Total TAC[d]
Sun Refining & Marketing Co.	Marcus Hook	PA	175,000	0	0	20	20
Sun Refining (formerly Chevron)	Phil.-Girard Point	PA	177,000	74	0	83	93
Sun Refining & Marketing Co.	Phil.-Point Breeze	PA	130,000	51	0	59	67
Tosco Refining Co.	Marcus Hook	PA	180,500	0	0	0	0
United Refining Co.	Warren	PA	66,700	84	771	149	235
Witco Chemical Co. Kendall-Arnalie	Bradford	PA	10,000	8	0	21	22
Mapco Petroleum Inc.	Memphis	TN	90,000	144	1,378	245	396
AGE Refining & Manufacturing	San Antonio	TX	5,000	0	0	0	0
Amoco Oil Co.	Texas City	TX	433,000	312	0	222	267
Basis Petroleum, Inc.	Houston	TX	67,600	59	0	61	69
Basis Petroleum, Inc.	Texas City	TX	125,400	80	1,333	265	402
Chevron USA Inc.	El Paso	TX	90,000	62	0	91	99
Citgo	Corpus Christi	TX	130,000	106	0	161	176
Clark Oil and Refining Corp.	Port Arthur	TX	185,000	65	0	63	72
Coastal Refining & Marketing Inc.	Corpus Christi	TX	95,000	78	0	120	131
Crown Central Petroleum Corp.	Pasadena	TX	100,000	88	1,513	282	437
Deer Park Refining Limited Partnership	Deer Park	TX	255,700	73	0	93	103
Diamond Shamrock Corp.	Three Rivers	TX	80,000	117	0	126	142
Diamond Shamrock Corp.	McKee	TX	135,000	109	0	100	115
Exxon Co. USA	Baytown	TX	411,000	2,362	0	1,909	2,222
Fina Oil & Chemical Co.	Big Spring	TX	58,000	73	2,815	369	644
Fina Oil & Chemical Co.	Port Arthur	TX	178,500	76	1,625	263	427
Howell Hydrocarbons & Chemicals Inc.	Channelview	TX	2,400	0	0	0	0
Koch Refining Co.	Corpus Christi	TX	280,000	203	0	203	233
LaGloria Oil & Gas Co.	Tyler	TX	52,000	72	625	170	239
Lyondell-Citgo Refining Co.	Houston	TX	258,000	240	12,602	1,538	2,761
Marathon Oil Co.	Texas City	TX	70,000	89	4,670	569	1,022
Mobil Oil Corp.	Beaumont	TX	320,000	51	9,263	1,100	1,980
Neste Trifinery Petrol. Srvc.	Corpus Christi	TX	30,000	0	0	0	0
Phillips 66 Co.	Borger	TX	120,000	74	7,582	934	1,659
Phillips 66 Co.	Sweeny	TX	200,000	102	0	99	114
Pride Refining Inc.	Abilene	TX	44,800	0	0	20	20
Shell Oil Co.	Odessa	TX	28,300	51	1,742	254	425
Star Enterprise	Port Arthur	TX	235,000	161	5,613	765	1,317
Valero Refining Co.	Corpus Christi	TX	29,900	56	0	59	67
Amoco Oil Co.	Salt Lake City	UT	52,000	159	0	99	124
Big West Oil Co.	Salt Lake City	UT	25,000	11	0	31	33
Chevron USA	Salt Lake City	UT	45,000	105	0	53	70
Crysen Refining Inc.	Woods Cross	UT	12,500	38	0	25	31
Phillips 66 Co.	Woods Cross	UT	25,000	0	58	45	56
Amoco Oil Co.	Yorktown	VA	56,700	107	3,937	506	892
Atlantic Richfield Co. (ARCO)	Ferndale	WA	202,000	408	0	210	270

Facility Name	City	State	Crude Capacity (bbl/cd)	10 year TCI[a]	20 year TCI[b]	Total AOC[c]	Total TAC[d]
Chevron USA Inc.	Seattle	WA	0	0	0	0	0
Shell Oil Co.	Anacortes	WA	108,200	102	4,437	577	1,010
Sound Refining Inc.	Tacoma	WA	11,900	0	0	0	0
Texaco Refining & Marketing Inc.	Anacortes	WA	138,500	124	0	142	160
Tosco Refining Co.	Ferndale	WA	88,500	107	0	84	99
US Oil & Refining Co.	Tacoma	WA	40,800	88	0	62	75
Quaker State Oil Refining Corp.	Newell	WV	10,500	20	0	32	35
Murphy Oil USA Inc.	Superior	WI	36,000	0	20	32	35
Frontier Oil & Refining Co.	Cheyenne	WY	38,950	0	0	20	20
Little America Refining Co.	Casper	WY	22,000	373	0	135	197
Sinclair Oil Corp.	Sinclair	WY	54,000	74	0	83	93
Wyoming Refining Co.	Newcastle	WY	11,875	11	0	31	33
Indusry Totals			$15,404,845	$23,102	$158,218	$35,876	$53,525

Notes:

[a] Total capital investment for capital with 10 year equipment life.
[b] Total capital investment for capital with 20 year equipment life.
[c] Total annual operating and maintenance costs.
[d] Total annualized costs computed at a 7 percent discount rate.

Source: EPA (1997b).

APPENDIX D

FINANCIAL SENSITIVITY ANALYSIS

Table D-1 presents the estimated impacts on firms' long-term debt to long-term debt plus equity ratios under the assumption that firms are debt-financing 70 percent of the capital necessary to comply with the proposed NESHAP (as opposed to 100 percent assumed in Section 4). Under the 70 percent debt-financing assumption, impacts on the long term debt to equity ratios are small. This result is not surprising considering impacts were small when we assumed capital would be entirely debt-financed.

Table D-1

IMPACTS ON DEBT RATIOS ASSUMING 70 PERCENT DEBT-FINANCING

	LTD / (LTD + E)[a]	
Firm Name	Pre-Control	Post-Control[b]
Amerada Hess Corp.	48.48	48.68
Amoco Oil Co.	21.06	21.09
Ashland Petroleum Co.	52.48	52.52
Chevron USA Inc.	24.52	24.53
Coastal	58.59	58.59
Conoco Inc.	40.23	40.24
Diamond Shamrock Corp.	60.52	60.54
Exxon Co. USA	16.13	16.15
Fina Oil & Chemical Co.	31.05	31.15
Marathon Oil Co.	53.97	53.99
Mobil Oil Corp.	20.50	20.54
Murphy Oil	15.67	15.74
Phillips 66 Co.	49.28	49.31
Shell Oil Co.	8.59	8.61
Sun Co.	34.33	34.33
Texaco Refining & Marketing Inc.	36.63	36.65
Unocal Corp.	55.79	55.80

Notes: [a] Long-term debt to long-term debt plus equity ratio.
[b] Assumes 70 percent debt-financing of investments in emission controls.
Source: Moody's Industrial Manual (1995).