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PROJECTIONS OF THE IMPACT OF EXPANSION OF DOMESTIC HEAVY OIL PRODUCTION ON THE U.S. REFINING INDUSTRY FROM 1990 TO 2010

Topical Report

By
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E. Bruce Ramzel
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December 1994

Performed Under Contract No. DE-FC22-83FE60149

IIT Research Institute
National Institute for Petroleum and Energy Research
Bartlesville, Oklahoma

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
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ABSTRACT

This report is one of a series of publications assessing the feasibility of increasing domestic heavy oil (10° to 20° API gravity) production. This report provides a compendium of the United States refining industry and analyzes the industry by Petroleum Administration for Defense District (PADD) and by ten smaller refining areas. The refining capacity, oil source and oil quality are analyzed, and projections are made for the U.S. refining industry for the years 1990 to 2010. The study used publicly available data as background. A linear program model of the U.S. refining industry was constructed and validated using 1990 U.S. refinery performance. Projections of domestic oil production (decline) and import of crude oil (increases) were balanced to meet anticipated demand to establish a base case for years 1990 through 2010. The impact of additional domestic heavy oil production, (300 MB/D to 900 MB/D, originating in select areas of the U.S.) on the U.S. refining complex was evaluated. This heavy oil could reduce the import rate and the balance of payments by displacing some imported, principally Mid-east, medium crude. The construction cost for refining units to accommodate this additional domestic heavy oil production in both the low and high volume scenarios is about 7 billion dollars for bottoms conversion capacity (delayed coking) with about 50% of the cost attributed to compliance with the Clean Air Act Amendment of 1990.

PREFACE

This report is one of a series of publications assessing the feasibility of increasing domestic heavy oil (10° to 20° API gravity) production. A summary of this report was presented in briefings at DOE Headquarters in Washington, D.C., on September 14, 1992, and at the DOE Bartlesville Project Office on November 6, 1992.

The goal of this part of the heavy oil study and this report was to determine the potential impact of increased domestic heavy oil production on the U.S. refining industry. Many of the light (>30° API gravity) and medium (20° to 30° API gravity) domestic oil reservoirs are mature, and oil production is rapidly declining. The nation's heavy oil resource has not been as extensively developed because of higher costs in production and lower oil quality (oil quality being reflected in the lower oil price refiners are willing to pay because they can obtain less high value product from heavier crude oil) relative to light crude oil. The questions that this study focused on include: If development of the domestic heavy oil resource were accelerated (Olsen, 1993) and the oil was delivered to the refinery gate, what impact would this have on the U.S. refining industry? Could U.S. refiners handle this larger volume (300 MB/D to 900 MB/D beyond the current 750 MB/D) of domestically produced heavy oil? What level of investment in upgraded refining capacity would be required to handle this additional domestic heavy oil? What imported oil would this domestically produced heavy oil displace from the market?

This study started in the fall of 1991, and the development of the linear programming models (LP) of the U.S. refining industry and the simulation of the effect of additional domestically produced heavy oil transpired during the spring and summer of 1992. Therefore, the data generated is currently somewhat dated. The decline of U.S. oil production and increasing U.S. dependence on imports of foreign oil are occurring at a faster rate than projected because of lower world oil prices due to plentiful oil on the world oil market and increased worldwide production capacity The divergence between imports and domestic production increases with lower oil prices as shown in Fig. 1 (DOE/EIA, 1993). Increasing attention is being given to the "price of imported oil" in terms of loss of domestic jobs; loss of tax revenues to federal, state, and local governmental bodies; the national trade deficit; and decreased productivity not only of the petroleum industry, but also other industrial sectors. Developing and using domestic oil (including the known heavy oil) resources could decrease this "price."

OBJECTIVE OF THE STUDY, METHODOLOGY AND STRUCTURE OF REPORT

The objectives of the National Institute for Petroleum and Energy Research's (NIPER) heavy oil feasibility study are to evaluate constraints to increasing domestic heavy oil production, specifically: (1) to investigate from secondary data the heavy oil resource, (2) to screen this resource for potential enhanced oil recovery applications, and (3) to evaluate various economic facets that may impact the development of this resource. Heavy oil is defined as having gas-free viscosity of >100 and <10,000 MPas (centipoise, cP) inclusive at original reservoir temperature, or a density of 943 kg/m^3 (20° API gravity) to 1,000 kg/m^3 (10° API gravity) inclusive at 15.6° C (60° F) (Group, 1981).

The focus of this study addresses the cost (investment level required for refining units, location and time frame) for refining units that would be required to process additional domestically produced heavy oil. NIPER contracted Bonner and Moore Management Science,

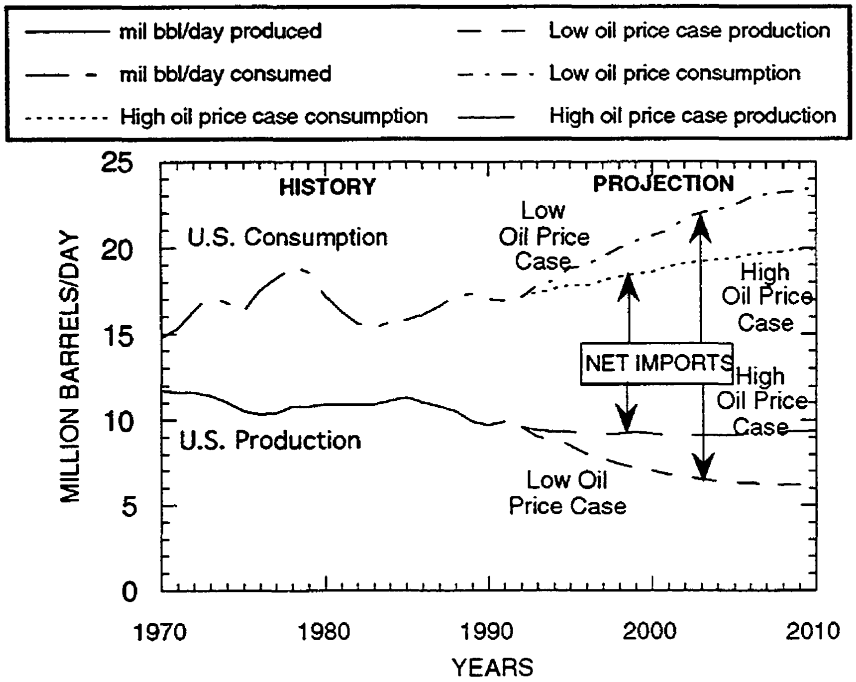

FIGURE 1 - Projections of oil production and imports through 2010 (EIA, 1991).

(B&M), a Houston based international refining consulting company, to conduct simulation studies to project the costs to the U.S. refining industry given the heavy oil production volumes, oil quality, location (region) and time frame for future domestic heavy oil production. Using this data from NIPER and information available in the public domain, B&M developed linear programming models (LP) of the U.S. refining industry and validated the model against the 1990 performance of the U.S. refining industry. Projections of the volumes and quality of crude necessary to meet U.S. product demand (i.e., using current refineries capacity, including previously announced upgrades and shutdowns to refineries as of the spring of 1992) were developed. Projections of future domestic production and import levels of crude oil by source, oil quality and volumes were made for the years 1990, 1995, 2000, 2005 and 2010. Projections of the costs, location (region) and time frames of unannounced upgrades (to refining units) required to handle additional (incremental future) domestically produced heavy oil were developed. The 1991 domestic heavy oil production (Olsen, 1993) is 750 MB/D or 10.3% of the 7,300 MB/D domestic oil production in 1991 (10.9% of the October 1993's 6,885 MB/D, domestic oil production).

This report is comprised of two parts: (1) a background, analysis and interpretation (Chapters 1-4) by NIPER of the research conducted by Guillermo Guariguata and Fredric Salmen of B&M who developed the linear programming model of the U.S. refining industry and conducted a series of computer simulations; and (2) the B&M reports submitted to NIPER (Volumes 1 and 2 and their final report (the appendices) containing the results of their analyses, collected data, and computer simulations. This report is based on publicly available data, and the tables and figures contained herein are a compendium of information on the U.S. refining industry from these sources. Figures are repeated as necessary for clarification and continuity of the report.

NIPER supplied, as input data for this study, the refining regions and projections of location, volume and time frame of additional heavy oil production (Olsen, 1991; Olsen, 1993). The low volume case scenario had a maximum additional heavy oil production rate of 300 MB/D, and the high volume case scenario had a maximum additional heavy oil production rate of 900 MB/D. Within the B&M report, these scenarios are sometimes referred to as low heavy and alternate high case, respectively.

ACKNOWLEDGMENTS

This work was sponsored by the U.S. Department of Energy under Cooperative Agreement DE-FC22-83FE60149 as project SGP37. The authors thank M. K. Tham of NIPER; W. D. Peters, and T. B. Reid of the DOE Bartlesville Project Office for their critical reviews; and Jonathan Grigsby, Rebecca Horning and Danny Lemmons for their assistance in preparing some of the graphics in Chapters 1-4.

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Olsen, D. K.: (NIPER) memorandum to A. Strycker (NIPER), dated December 26, 1991 on Projected Additional Heavy Oil to the Year 2010.

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Chapter 1

EXECUTIVE SUMMARY

This report is one of a series of publications assessing the feasibility of increasing domestic heavy oil production. Each report covers a select topic or geographic area of the United States and evaluates the heavy oil resource in that area in terms of geology, oil-in-place, production and refining capabilities. This analysis and report assesses the impact of additional domestic heavy oil production on the U.S. refining complex under three different production level scenarios: no new heavy oil (base case), low heavy oil—increase in domestic production of 300 MB/D of heavy oil, and high heavy oil—increase in domestic heavy oil production of 900 MB/D. This report is comprised of two parts: a background, analysis and interpretation by NIPER of its own research on the impact of increased domestic heavy oil production on the U.S. refining industry between the year 1990 and 2010, and the research conducted by Bonner and Moore Management Science which developed a linear programming (LP) model and conducted simulations of the U.S. refining industry. Petroleum Administration for Defense Districts (PADD) and 10 smaller production and refining areas were identified for the purpose of conducting the series of computer simulations of possible oil refining scenarios and determining the impact of the domestically produced heavy oil.

This report developed three scenarios for the U.S. refining industry from 1990 to 2010. Although the emphasis of the study was to evaluate the impact of additional domestic heavy oil production (beyond the 1992 production level of about 750 MB/D of 10° to 20° API gravity crude oil), the base case (i.e., no new heavy oil) contains a number of key points that reflect the future of the U.S. petroleum industry.

CONCLUSIONS FOR NO NEW HEAVY OIL SCENARIO

* The U.S. demand for petroleum products is anticipated to grow at a conservative 1% per year during the 1990 to 2010 period. Most of the growth will be in the liquid transportation fuel sector. To meet that demand, the U.S. will import increasing volumes of crude oil and refined product. The volume of imports dwarfs the volumes of incremental heavy oil considered in this study and soon will exceed the entire U.S. oil production.

* By the year 2010, nearly 70% of the oil used will be imported, and this volume of imports dwarfs the volumes of incremental heavy oil considered in this study. The "more than fifty percent threshold" of imports to domestic crude supplies will probably occur by the year 1996 and possibly as early as 1994 (assuming low oil prices and continued opposition to produce in "environmentally sensitive" areas such as the Alaskan National Wildlife and Arctic Refuge or offshore California).

* Despite all efforts by non-Middle Eastern OPEC members to expand their crude production capabilities, Middle Eastern producers will be the main source of incremental supplies to the U.S. refiners during the next 20 years. Other sources will contribute with more modest volumes.

* A 2% per year decline in domestic crude supplies, mainly in terms of Alaska North Slope (ANS) and Midwest light sweet crude, will increase the dependency of domestic refineries on imported crude.

* Loss of ANS production will significantly affect the current U.S. crude supply logistics and cause an additional cost burden on refined product prices.

* Idle West Coast refining capacity will require crudes otherwise destined to other areas in order to meet consumer demand.

* Midwestern inland refineries will increase the dependency on import crudes to make up their crude shortfall. The current pipeline system will reverse some of its traditional flow patterns.

Projections, for the years 1990 to 2010 (in five-year increments), for domestic oil production and imports of crude oil that will meet domestic demand are summarized in Figs. 1.1 through 1.3 (all volumes in thousands of barrels per day, MB/D). Domestic oil production in 1990 was 7,400 MB/D and is anticipated to fall below 4,500 MB/D in 2010. Imports to the U.S. in 1990 were 5,900 MB/D and are anticipated to increase to 9,800 MB/D by 2010. In Fig. 1.1, the boxes for PADDs (1, 2 & 4, 3), California and Alaska show domestic production by year in

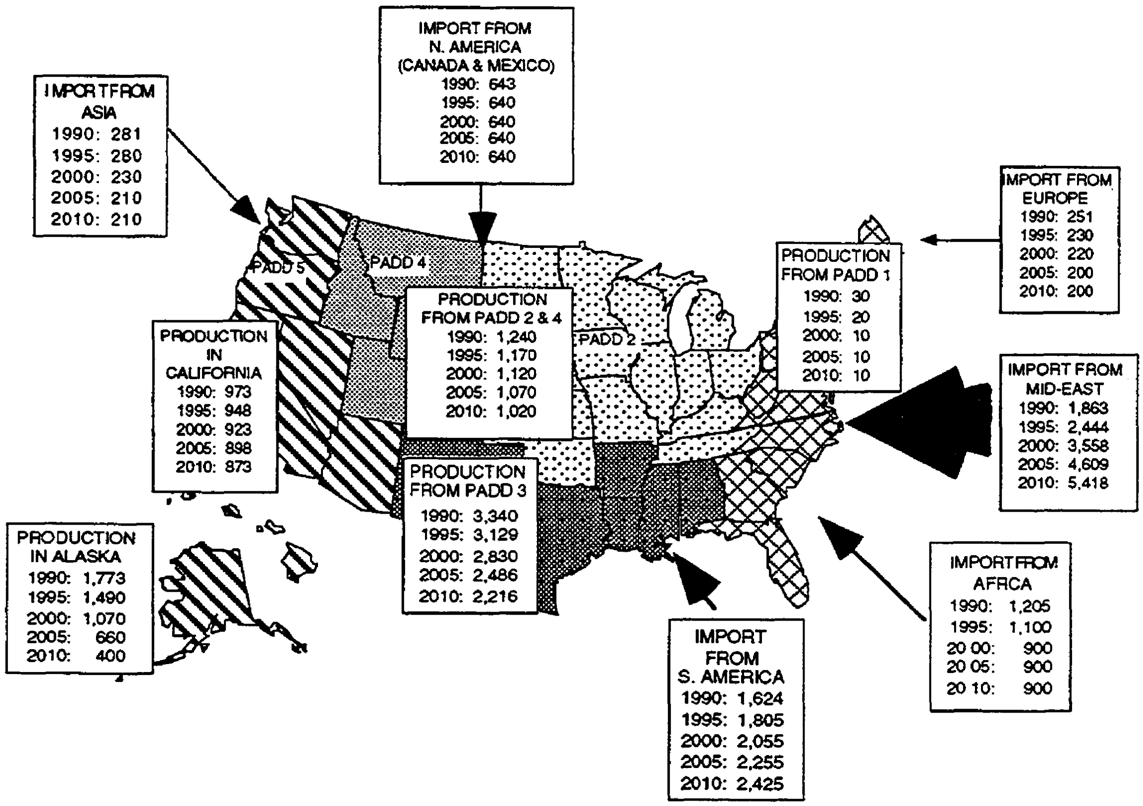

FIGURE 1.1 - **Projections of domestic oil production and imports necessary to meet U.S. demand for the years 1990 to 2010.**

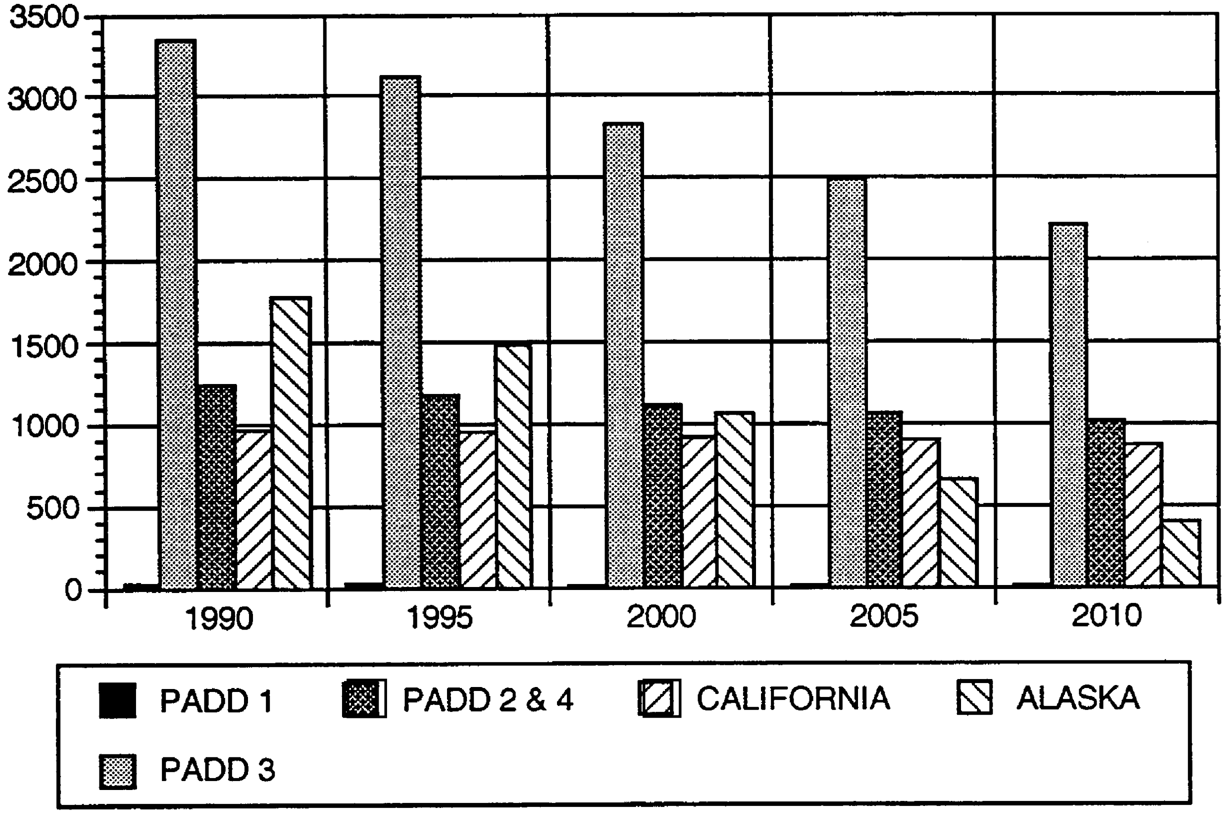

FIGURE 1.2 - Projected decline in domestic oil production.

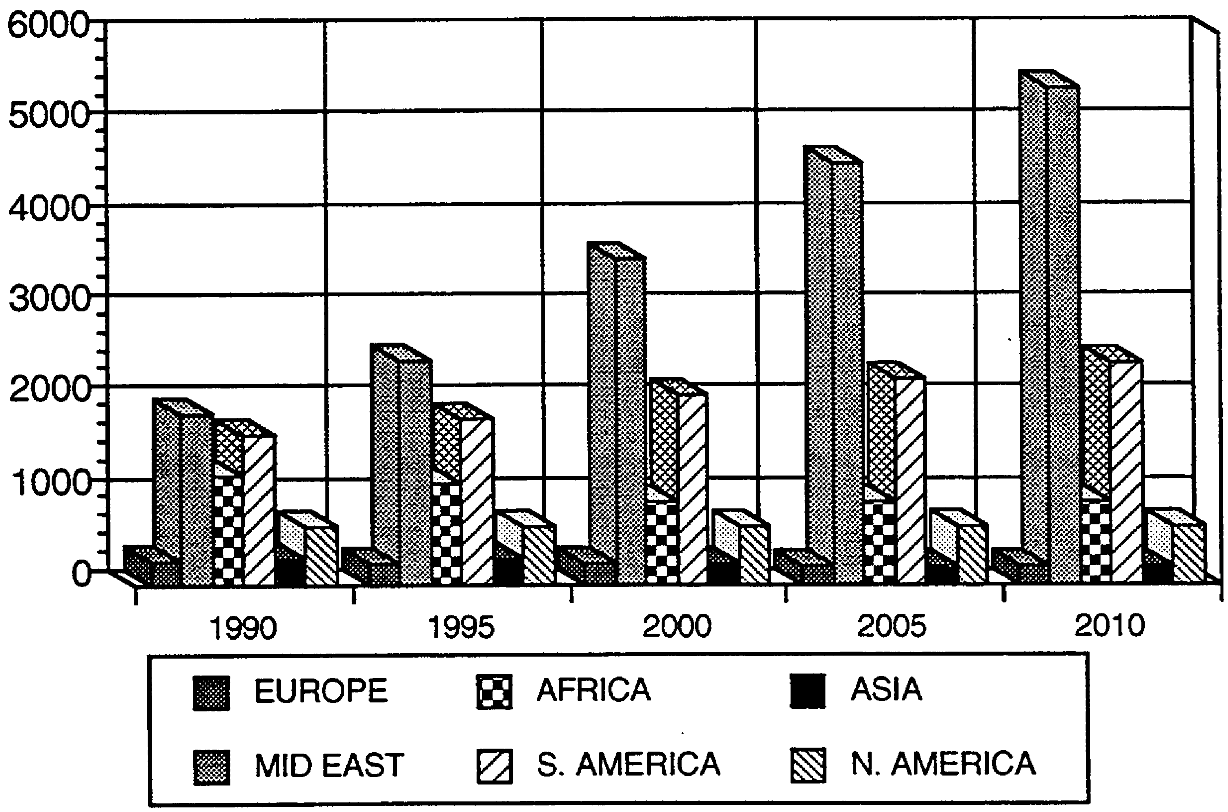

FIGURE 1.3 - Projected imports of crude oil by area of origin.

five year increments. Imported oil is shown by area of origin and reflects anticipated oil import levels. The size of the arrows reflect the relative magnitude of imports. The greatest decline in U.S. production is anticipated from Alaska, and the largest import source is anticipated to be the Mid-east. The 2010 imports level from the Mid-east is nearly three times the 1990 import level from that area. The same data is shown in bar graphs in Fig. 1.2 (declining U.S. production) and Fig. 1.3 (increasing oil imports).

Significant increases in crude imports are required to meet demand. Historic levels of domestic production, imports of crude oil and refined products required to meet U.S. demand are shown in Fig 1.4 (API, 1993). The projections made within this NIPER report assume that petroleum products consumption will experience a modest yearly growth rate of 1% per year through 2010. Crude supplies to U.S. refineries will increase their dependency on imports as domestic production declines about 2% per year.

The Energy Information Administration (EIA, 1993, p. 9) recently published projections of domestic oil production and imports to the year 2010 using a low oil price case ($18 in 2010 in 1991 dollars/bbl) and a high oil price case ($38 in 2010 in 1991 dollars/bbl) as shown in Figs. 1.5 and 1.6. The projections developed from the base case shown in Fig. 1.7 from the analysis

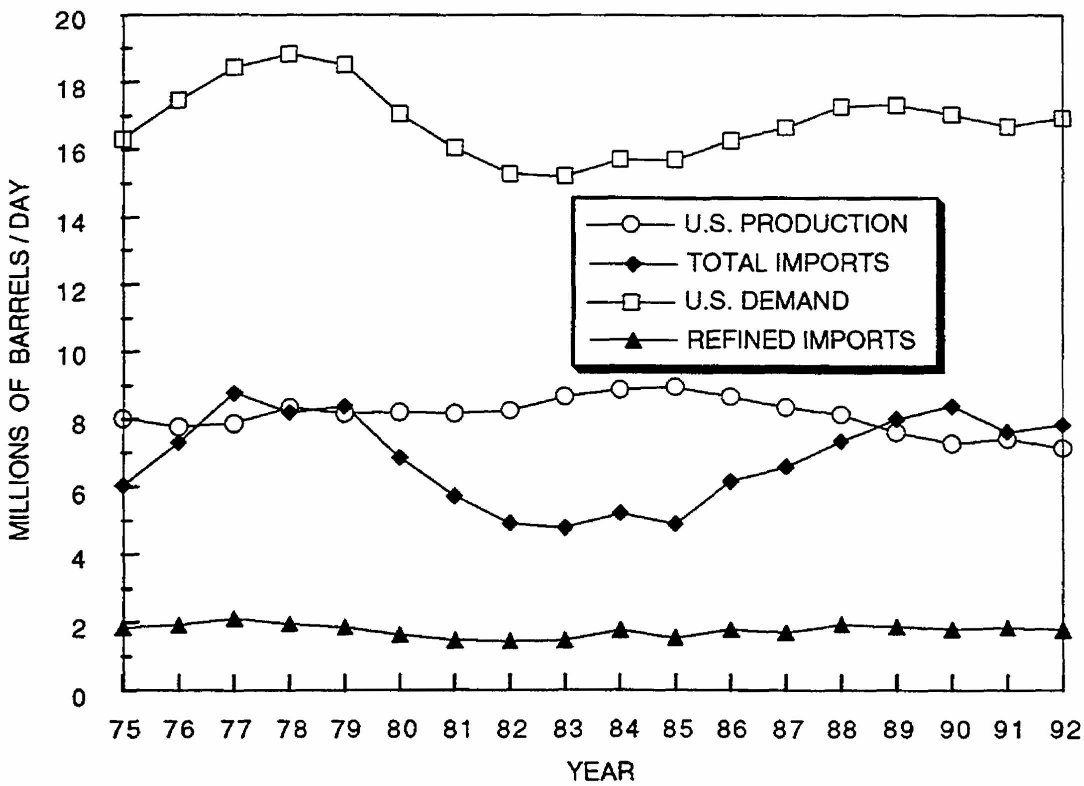

FIGURE 1.4 - Historical U.S. oil demand, domestic production and imported crude oil and refined products (API, 1993).

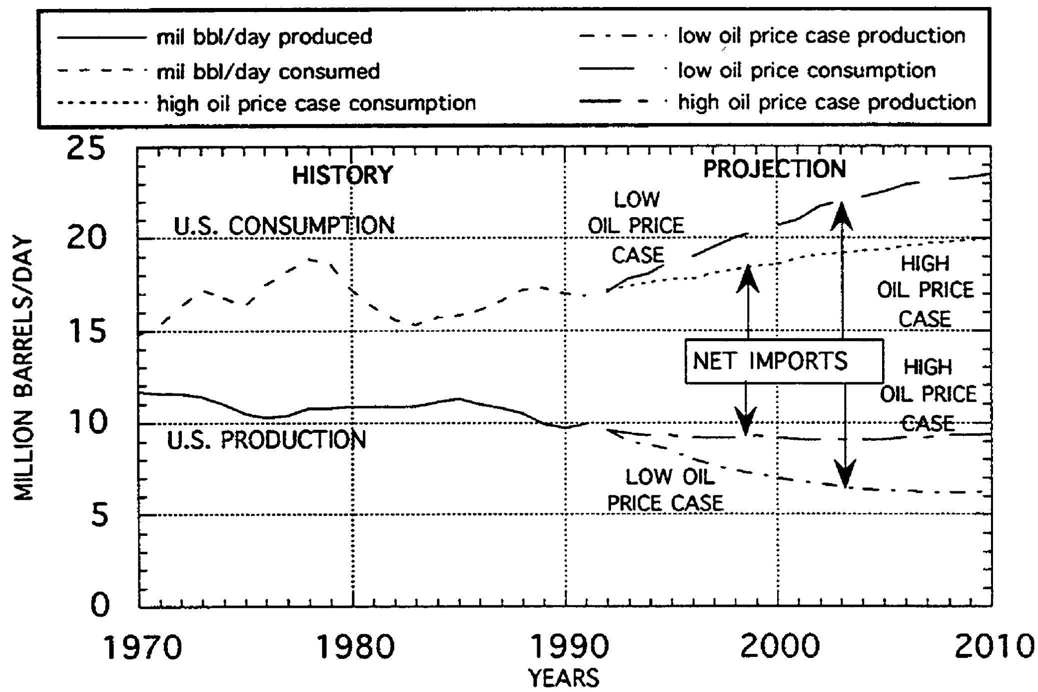

FIGURE 1.5 - EIA 1991 projections of U.S. oil demand (consumption) and domestic production resulting in net imports under high oil price and low oil price projections.

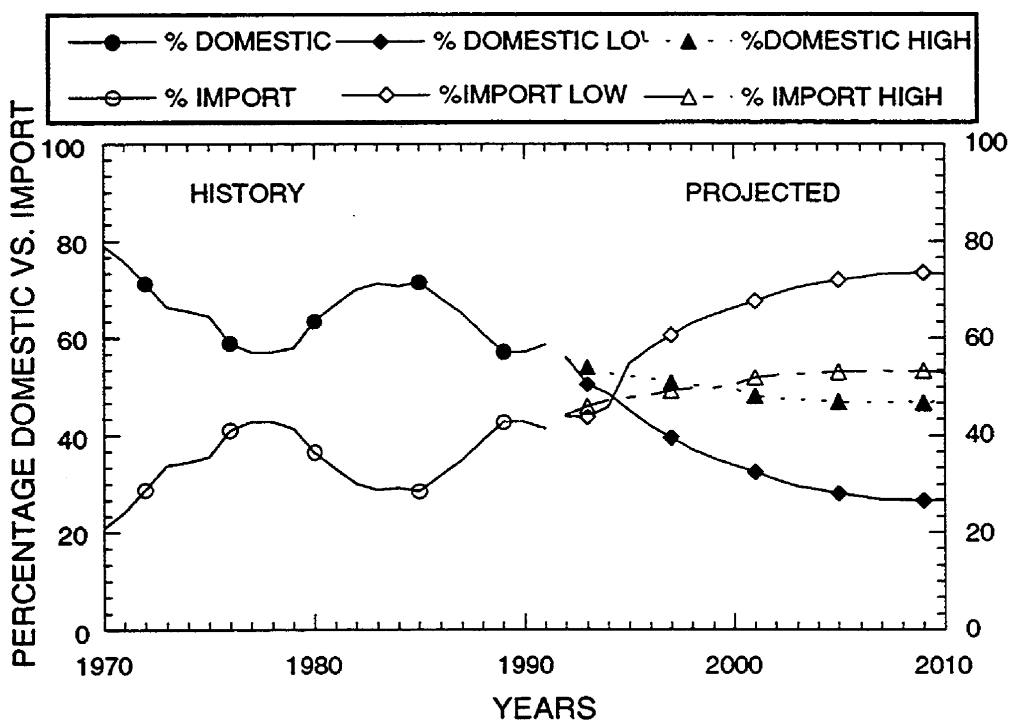

FIGURE 1.6 - Percentage of oil from domestic production and from imports based on historical record and EIA projections of U.S. oil demand (consumption) and domestic production through the year 2010 (replot of data from EIA, 1991, p. 19).

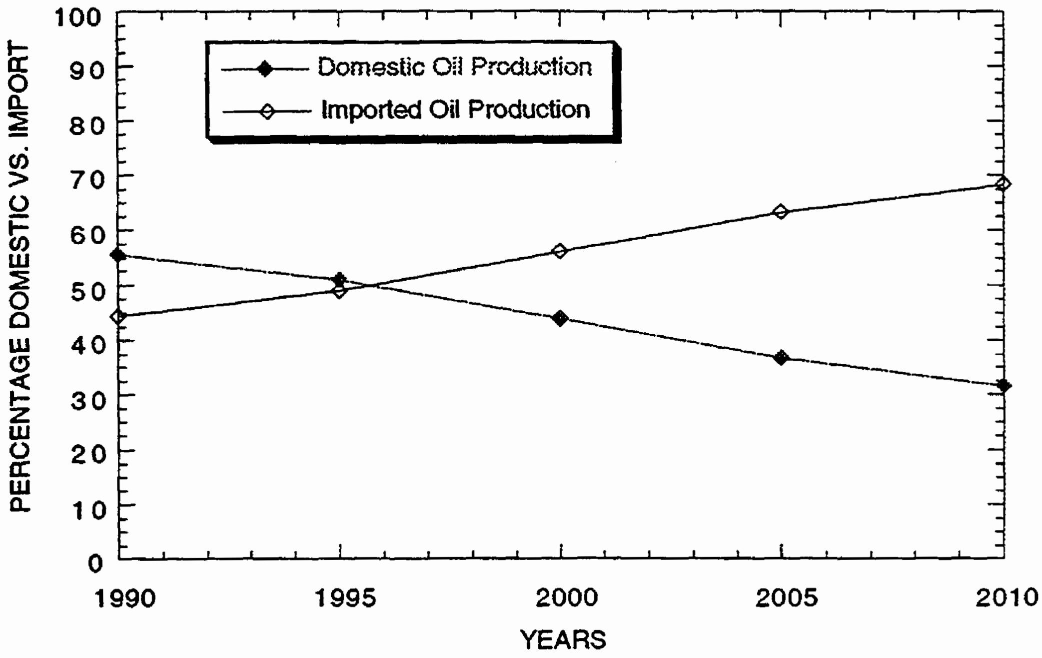

FIGURE 1.7 - NIPER projections of oil production and imports on a percentage basis through the year 2010.

developed in NIPER study of domestic oil production and imports are consistent with those of EIA and show approximately the same cross over point (50% import rate) and final endpoints (import rates in the year 2010).

NEW (ADDITIONAL) HEAVY OIL CONCLUSIONS

* NIPER believes the low case (300 MB/D of incremental domestic heavy oil production) is an achievable production rate, and the high case (900 MB/D) is a target. Current (1992) domestic production of heavy oil is 750 MB/D. These volumes of incremental heavy oil are significant additions to the current domestic production. Production of this incremental heavy oil would alter the U.S. production decline curve, provide a domestic economic base and jobs, using a U.S. resource. This would add flexibility to the U.S. refining industry in terms of secure supply.
* In order to process the incremental domestic heavy oil at both the High (900 MB/D) and Low (300 MB/D) production rate scenarios, the following bottoms conversion capacity (delayed coking) must be constructed in the refining regions defined in Figure 1.8.
* Some fully used existing refining capacity will be freed up as ANS and PADD 3 production declines.
* In both of the heavy oil production rate scenarios, over a twenty year span, the U.S. refining industry would be faced with capital expenditures in the $7 billion range. Of the $7 billion, approximately $1 billion would be required to refurbish existing primary refining capacity to accommodate demand growth, $3 billion to build the necessary conversion capacity to process the additional domestic heavy oil, and $3 billion to comply with the 1990 Amendments to the Clean Air Act (CAA) and quality treatment of intermediate streams.

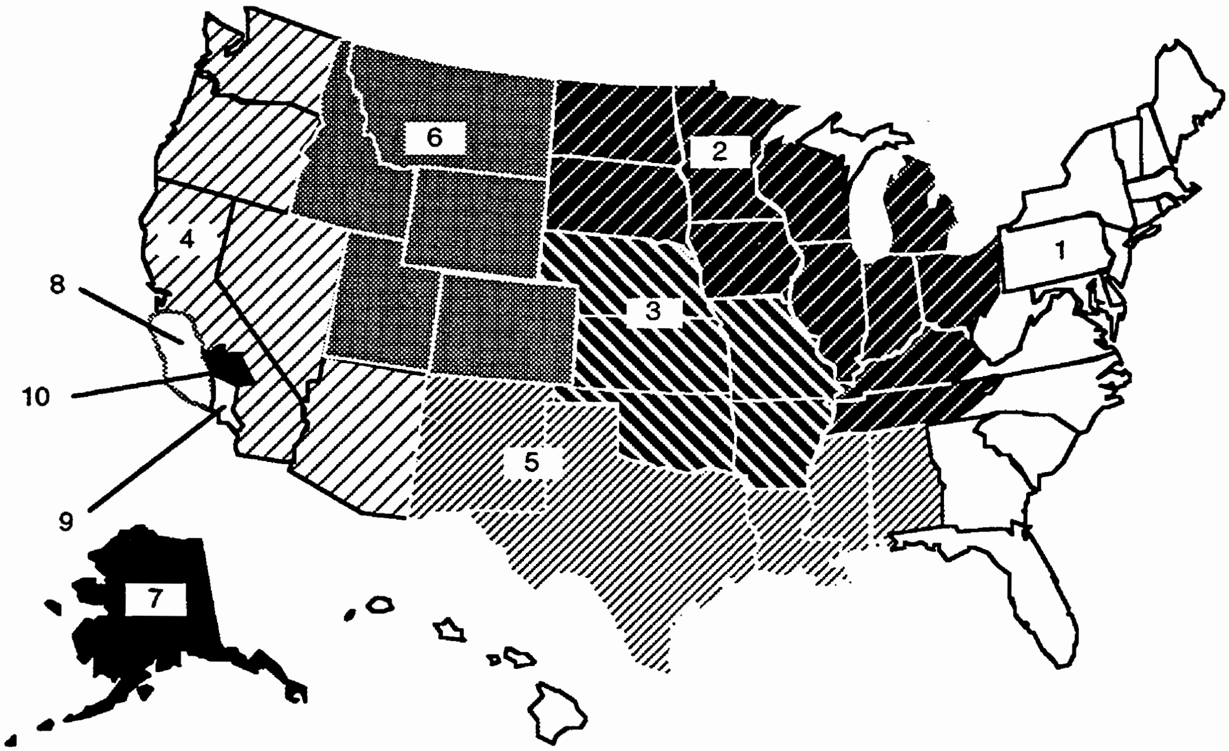

FIGURE 1.8 - Ten refining areas analyzed in this NIPER study.

CONVERSION CAPACITY BY 2010

	MB/D	
Region	High	Low
1	17	17
2 & 3	90	87
4	11	-
5	162	100
6	30	26
Total	310	230

* Investment costs attributable directly to compliance with the regulation of the CAA are estimated at $3 billion which are in line with the petroleum industries $33 billion estimate of CAA costs.

The details of the no new heavy oil projections and those scenarios with additional (incremental) domestic heavy oil production can be found in Chapter 3. The costs of refining upgrades are summarized in Chapter 4; and the B&M report volumes 1 and 2. An update to simulations of the U.S. Gulf Coast, with higher sulfur and lower API gravity crude, are included as appendices.

To pay for all the environmental and unit costs for expansion required to process the additional domestic heavy oil, refining margins must be considered. Figure 1.9 is from refining

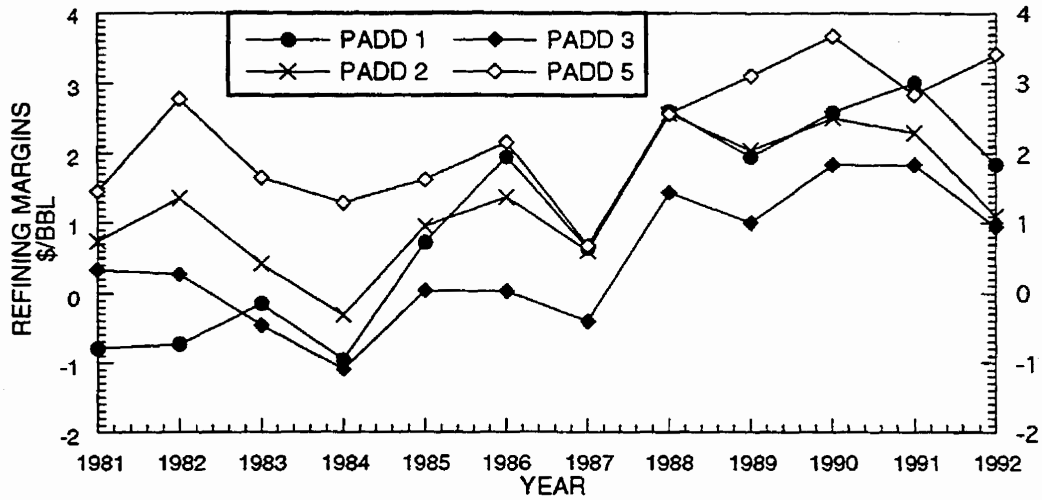

FIGURE 1.9 - Refining margins of the last decade in 1990 dollars (Wright Killen, 1993).

margin data supplied by Wright Killen (1993). Although Fig. 1.9 shows increased margins in recent years, most of the profit is being applied to meeting environmental restrictions for product quality and upgrading to comply with CAA. Funds are scarce for construction, expansion, and upgrading of heavy oil processing capacity.

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Chapter 2

BACKGROUND

U. S. PETROLEUM PRODUCTION INDUSTRY

Current Levels of Domestic Heavy Oil Production

Heavy oil, as used in this study, is defined as having gas-free viscosity of >100 and <10,000 MPas (centipoise, cP) inclusive at original reservoir temperature or a density of 943 kg/m^3 (20° API gravity) to 1,000 kg/m^3 (10° API gravity) inclusive at 15.6° C (60° F) (Group, 1981). Figure 2.1 shows a map of the U.S. with the principal heavy oil producing reservoirs and Petroleum Administration for Defense Districts (PADDs) boundaries, whereas Fig 2.2 shows many of the 1,400 U.S. heavy oil reservoirs. Table 2.1 shows NIPER's estimates of 1991 domestic heavy oil production. NIPER's analysis of heavy oil reservoir data for states outside California indicates that previous estimates of heavy oil resources (Dietzman et. al., 1965; Kujawa, 1981; Interstate Oil Compact Commission, 1984; Crysdale and Schenk, 1990, Piper et. al., 1983) included significant light oil because data included total field production rather than production for only heavy oil reservoirs. Based on these analyses, the remaining U.S. heavy oil

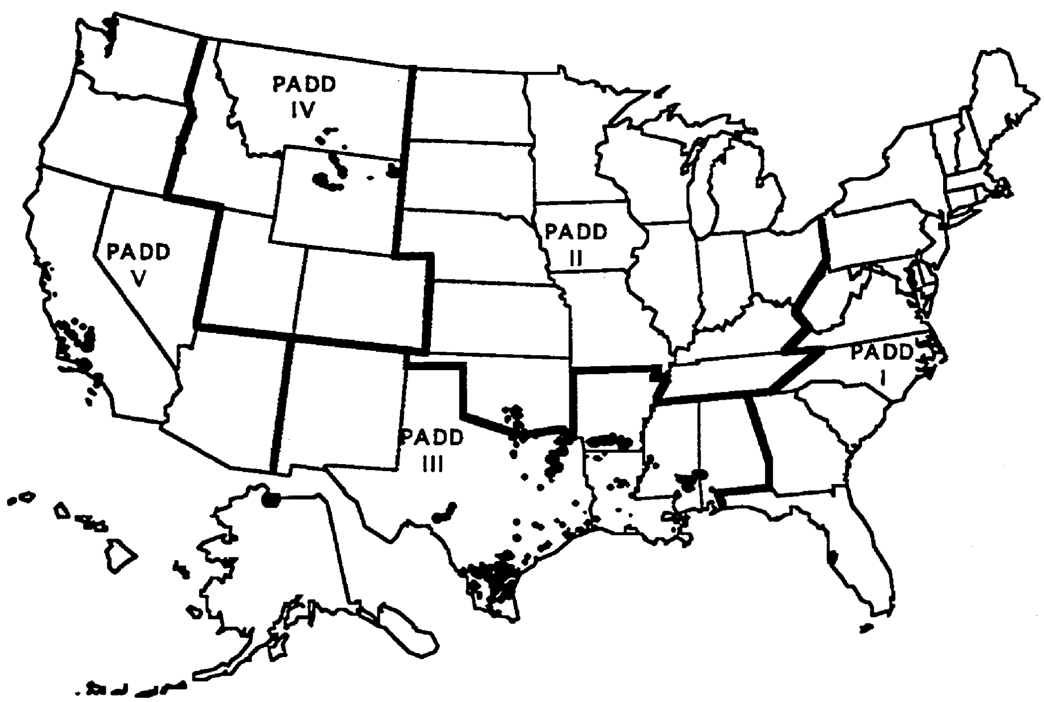

FIGURE 2.1 - Map of the United States showing principal heavy oil field locations and Petroleum Administration for Defense Districts (PADDs) boundaries.

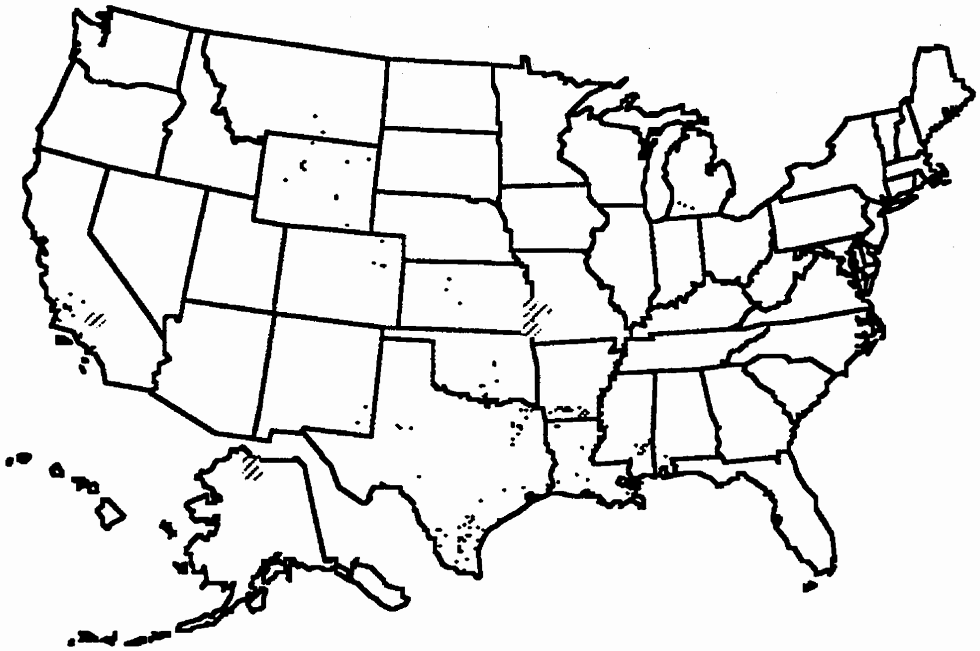

FIGURE 2.2 - Map of the United States showing heavy oil field locations (Crysdale and Schenk, 1990)

TABLE 2.1
Estimated (1991) Daily Heavy Oil Production by State

Area	bbl/day	Source
Alabama	990	(1)
Arkansas	11,300	(2)
California	655,700	(3)
Kansas	964	(4)
Louisiana	11,085	NIPER estimate
Mississippi	9,055	(5)
Missouri	16	(6)
New Mexico	2,000	NIPER estimate
Oklahoma	3,200	NIPER estimate
Texas	29,530	(7)
Wyoming	>18,250	(8,9)
PADD 1 all of East Coast	0	NIPER estimate
PADD 2 except states above	<250	NIPER estimate
PADD 4 except Wyoming	2000	NIPER estimate
Alaska	>3,000	(10,11)
All other	<1,000	NIPER estimate
TOTAL	approximately 750,000	

For references see Olsen, NIPER-606, July 1993, Table 1, p. 7.

resource was adjusted by NIPER to 80 to 90 billion bbl. Of the U.S. heavy oil, California has by far the most, perhaps as high as 60 billion bbl, with Alaska reported as having 5-20 billion bbl, and the Gulf Coast states and Wyoming having most of the rest. California is by far the major heavy oil producer, followed by the Gulf Coast states (10% the level of California's production) of Texas, Louisiana, Mississippi, and Arkansas. Wyoming is the remaining heavy oil producer with about 3% of the total. Other states have significantly lower percentages. Except for Alaska, these totals generally follow the regional resource pattern for heavy oil (Olsen, Taylor and Mahmood, 1992).

Projected U.S. Heavy Oil Production Levels, Quality, Location and Time Frame

Projections for three potential heavy oil production levels (incremental above current production levels) were developed in a 1991 study and are listed in Tables 2.2-2.4 (Olsen, 1990) and the rational has been described (Olsen, 1993). These projected future heavy oil volumes and the oil quality data (API gravity and sulfur content) shown in Table 2.5 (Olsen, 1990; Olsen, 1993) were used as input data in addition to other publicly available data, for the computer simulation effort by B&M to estimate the impact of processing this additional domestically produced heavy oil on the U.S. refining industry. Ten refining areas (Fig. 2.3, sometimes referred to as DOE regions in the B&M appendices) were defined in this refining assessment and consider all refining capacity in the area as a composite unit for simulation purposes.

TABLE 2.2

Projected Heavy Oil Production Levels and Time Frames for an Additional 900 MB/D

		Additional crude oil			
PADD	**General location**	**BOPD 1995**	**BOPD 2000**	**BOPD 2005**	**BOPD 2010**
1	Entire PADD 1	0	0	0	0
2	Midcontinent (KS, MO, OK)	1,000	2,000	3,000	5,000
2	Remainder of PADD 2	0	100	500	<1,000
3	Permian Basin	1,000	1,000	2,500	<5,000
3	East Texas	2,000	10,000	20,000	80,000
3	SE. Arkansas & N. Louisiana	2,000	15,000	50,000	130,000
3	South Texas Basin	1,000	10,000	50,000	130,000
3	Texas Gulf Coast Salt Basin	5,000	10,000	50,000	130,000
3	Louisiana Gulf Coast Salt Basin	1,000	10,000	25,000	75,000
3	Mississippi Interior Salt Basin	0	500	1,000	<5,000
4	Wyoming, Montana	1,000	10,000	20,000	>40,000
5	San Joaquin Valley	40,000	40,000	90,000	200,000
5	Los Angeles Basin	-5,000	-10,000	-2,000	-1,000
5	Coastal Range California	30,000	50,000	75,000	100,000
5	North Slope, Alaska	10,000	11,000	15,000	30,000
	TOTAL	91,000	158,500	400,000	930,000
	TOTAL APPROXIMATE VALUES	90,000	150,000	400,000	900,000

TABLE 2.3

Projected Heavy Oil Production Levels and Time Frames for an Additional 500 MB/D

PADD	General location	Additional crude oil BOPD 1995	BOPD 2000	BOPD 2005	BOPD 2010
1	Entire PADD 1	0	0	0	0
2	Midcontinent (KS, MO, OK)	1,000	2,000	3,000	5,000
2	Remainder of PADD 2	0	100	500	<1,000
3	Permian Basin	1,000	1,000	2,500	<5,000
3	East Texas	2,000	10,000	20,000	>25,000
3	SE. Arkansas & N. Louisiana	2,000	15,000	50,000	100,000
3	South Texas Basin	1,000	10,000	50,000	100,000
3	Texas Gulf Coast Salt Basin	5,000	10,000	50,000	100,000
3	Louisiana Gulf Coast Salt Basin	1,000	10,000	25,000	50,000
3	Mississippi Interior Salt Basin	0	500	1,000	<5,000
4	Wyoming, Montana	1,000	10,000	20,000	>25,000
5	San Joaquin Valley	40,000	40,000	90,000	150,000
5	Los Angeles Basin	-5,000	-10,000	-15,000	>-20,000
5	Coastal Range California	30,000	50,000	50,000	70,000
5	North Slope, Alaska	10,000	11,000	5,000	5,000
TOTAL		91,000	158,500	317,000	561,000
TOTAL	APPROXIMATE VALUES	90,000	150,000	300,000	500,000

TABLE 2.4

Projected Heavy Oil Production Levels and Time Frames for an Additional 300 MB/D

PADD	General location	Additional crude oil BOPD 1995	BOPD 2000	BOPD 2005	BOPD 2010
1	Entire PADD 1	0	0	0	0
2	Midcontinent (KS, MO, OK)	1,000	2,000	3,000	5,000
2	Remainder of PADD 2	0	0	0	0
3	Permian Basin	0	0	1,000	<2,000
3	East Texas	2,000	5,000	10,000	>20,000
3	SE. Arkansas & N. Louisiana	2,000	15,000	25,000	50,000
3	South Texas Basin	1,000	10,000	25,000	40,000
3	Texas Gulf Coast Salt Basin	5,000	10,000	25,000	40,000
3	Louisiana Gulf Coast Salt Basin	1,000	5,000	10,000	25,000
3	Mississippi Interior Salt Basin	0	0	0	0
4	Wyoming, Montana	1,000	5,000	8,000	8,000
5	San Joaquin Valley	40,000	40,000	40,000	65,000
5	Los Angeles Basin	-5,000	-10,000	-15,000	>-20,000
5	Coastal Range California	30,000	50,000	50,000	50,000
5	North Slope, Alaska	10,000	10,000	11,000	>15,000
TOTAL		88,000	142,500	193,000	300,000
TOTAL	APPROXIMATE VALUES	90,000	140,000	190,000	300,000

TABLE 2.5

Composition of Projected Heavy Oil

PADD	General location	Additional crude oil: Range, gravity, °API	Additional crude oil: Sulfur, %
2	Midcontinent (KS, MO, OK)	16	2
2	Remainder of PADD 2	16-20	0.5
3	Permian Basin	15-20	2
3	East Texas	12-18	>2
3	SE. Arkansas & N. Louisiana	13-20	2.5
3	South Texas Basin	18-20	0.5
3	Texas Gulf Coast Salt Basin	16-20	0.5
3	Louisiana Gulf Coast Salt Basin	16-20	0.7
3	Mississippi Interior Salt Basin	16-20	0.7
4	Wyoming, Montana	13-20	2.5
5	San Joaquin Valley	10-15	1.2
5	Los Angeles Basin	16-20	1.5
5	Coastal Range California	13-19	>2.5
5	Offshore California	13-20	>2.5
5	North Slope, Alaska	14-20	>1.5

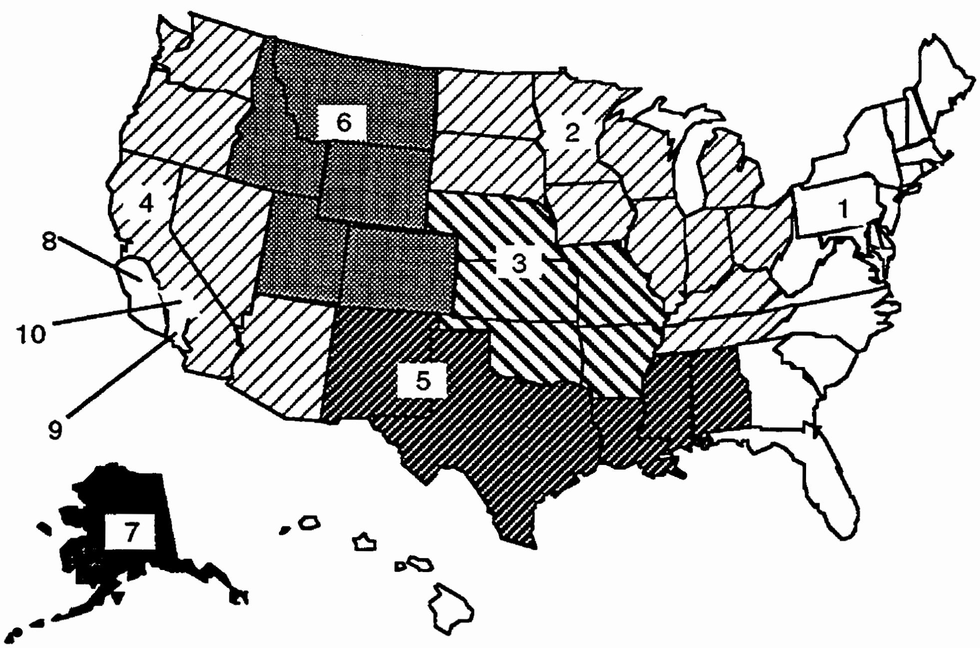

FIGURE 2.3 - Ten refining areas analyzed in this NIPER study.

Each region (Fig. 2.3) was considered a homogeneous unit from a production and refining standpoint. Capabilities, product requirements and regulations differed from region to region, but were considered uniform throughout each region. Also, oil produced within a region was refined in that region. Some exceptions to this were made during the study when major volumes of interregional transport of oil was found (principally California regions 8, 9 and 10) to be necessary.

U.S. Petroleum Refining Industry

Refining History

The U.S. petroleum refining industry has changed significantly during the last decade due to the phase out of lead as an octane booster and the change to cleaner fuels to meet the guidelines of the Clean Air Act and its amendments. This evolution toward cleaner fuels is anticipated to continue during the next two decades. This refining impact study on heavy oil considered the impact of the 1990 Amendments to CAA and implementation of the California Air Resources Board (CARB) fuel standards for California. It did not consider unknown standards of future legislation such as adoption of CARB standards by other states. A historical summary of the U.S. petroleum refining industry has been compiled (EIA, 1990). The U.S. refining capacity (nameplate volume of a refinery) and utilization (total, actual volume processed) are shown in Fig 2.4 (EIA, 1990). Since operating capacity peaked in 1980, the number of U.S. refineries has declined by 120 (Olsen and Ramzel, 1991). Small to medium size (<50 MB/D) refineries close while larger refineries, because of economies of scale, continue to maintain operating capacity. The CAA requirements could reduce the U.S. refining capacity by 1,500 MB/D (Oil & Gas J., 1992) before the year 2000.

Oil Processed in U.S. Refineries

The quality of oil being refined in U.S. refineries is declining as shown in Fig 2.5. The sulfur content continues to increase. In recent years, the API gravity (which saw a rapid decline in the early 1980's) has begun to stabilize around 31° API gravity (EIA, 1992; Olsen, Ramzel and Pendergrass, 1993). This is expected since the average API gravity of imported Mid-east crude is 32.9 API and contains 1.8 % sulfur.

Imports of Crude Oil

The U. S. imports increasing volumes of refined product and crude oil. The percentage of total imports by API gravity range is shown in Fig. 2.6. The figure reflects the investments made in the mid- to late 1970's in heavy oil processing capacity in the U.S. This permitted significantly larger volumes of heavier gravity oil to be refined in the late 1970's and early 1980's. As new lighter oil was found (domestic and foreign) due to increased exploration and

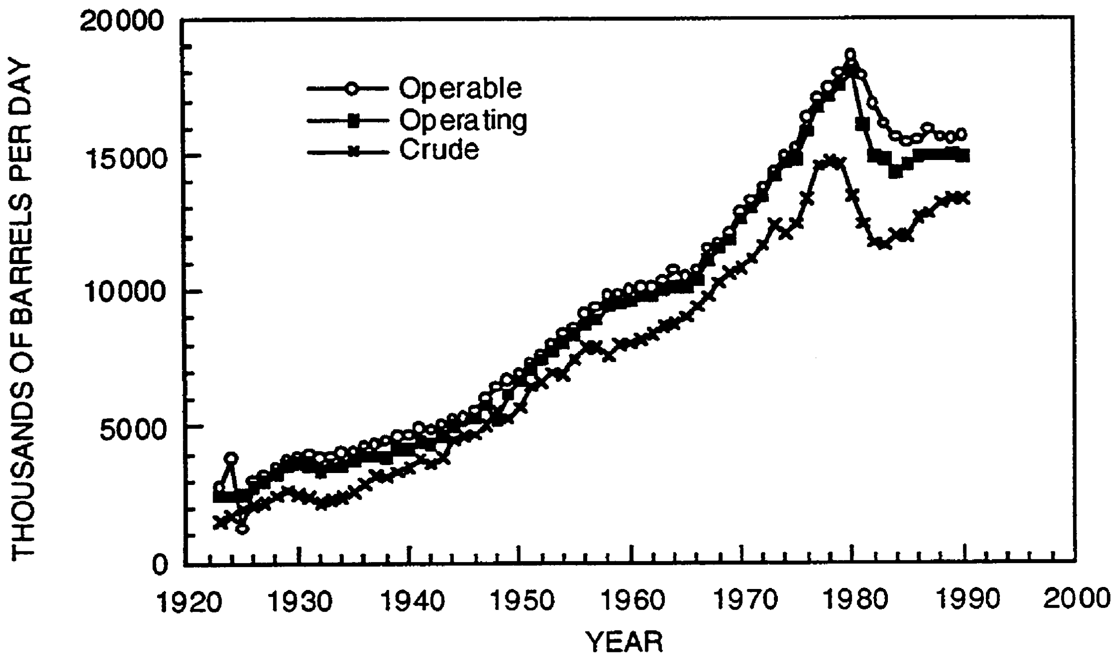

FIGURE 2.4 - Refining history in the United States (EIA, 1990).

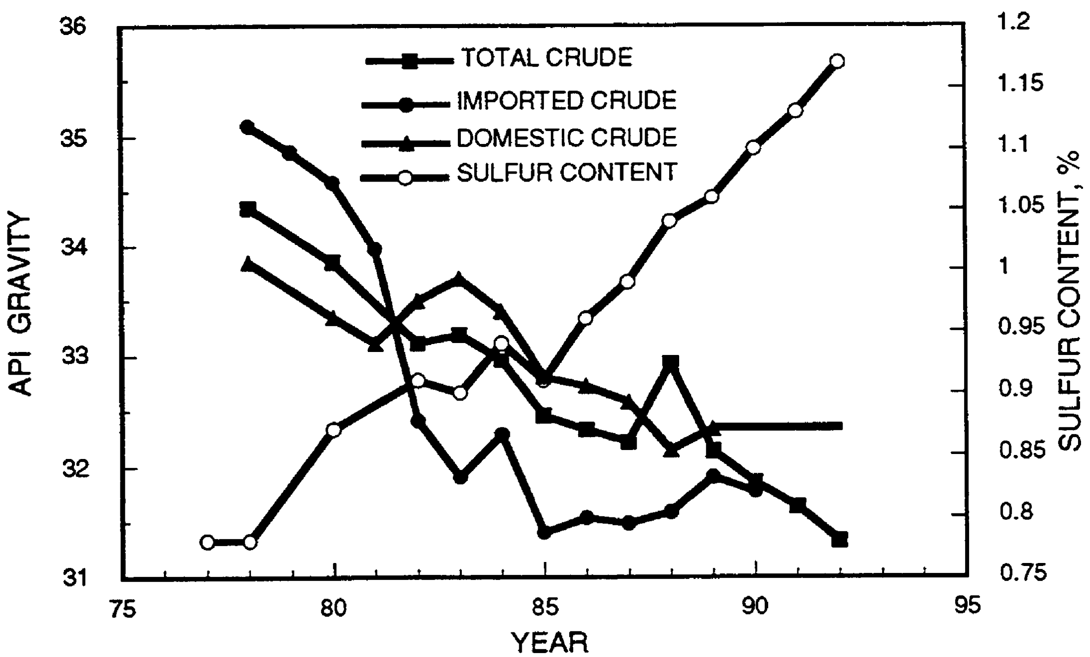

FIGURE 2.5 - Crude oil quality in the United States, percent Sulfur and API gravity.

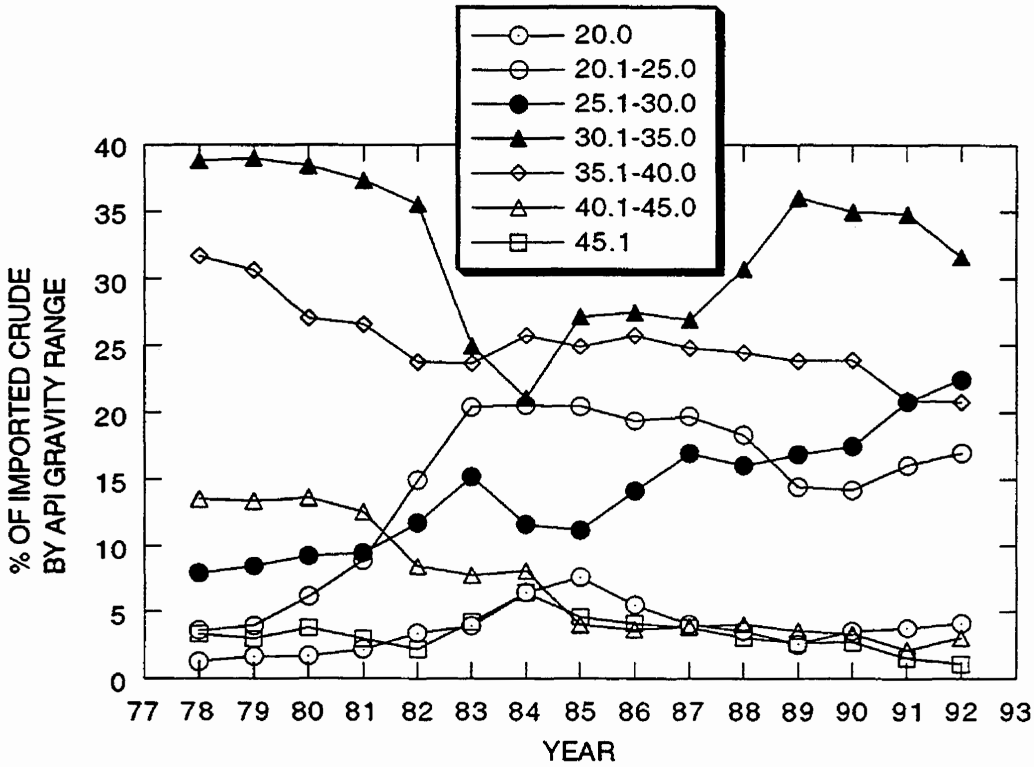

FIGURE 2.6 - Percent of total imported oil by API gravity.

development spurred by the high oil prices of the late 1970s and early 1980s, the investment and interest in heavy oil refining capacity declined. Increasing volumes of lighter crudes began to be processed (as they became available) because there is a higher margin on refining light oil into high value products than in refining heavy oil.

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Chapter 3

PROJECTIONS

INTRODUCTION

The projections in this study and conclusions drawn from the analyses of these projections are divided into the base case (no new heavy oil) followed by the two scenarios where additional domestic heavy oil is added to the crude oil supply (300 MB/D and 900 MB/D) both of which displace imported oil. Some of the tabular data presented in the appendices have been converted to a graphic presentation superimposed on the map of the U.S. They reflect a snapshot in time of the volumes (MB/D), oil gravity, origin (domestic or imported), total volume and percentage of the total projected oil to be refined in an area.

BASE CASE (NO NEW HEAVY OIL)

Projected Volumes, Quality and Origin

Assuming a U.S. petroleum demand growth rate of 1%, U.S. refining industry structure, world wide petroleum supply and distribution capability, projections were made to meet projected U.S. petroleum product demand. The projected volumes (MB/D), quality and origin of the crude oil that U.S. refineries will process between 1990 and 2010 are shown (MB/D) in Table 3.1, Figs. 3.1 and 3.2. The sum of domestic production by PADD and imports (by region of origin)

TABLE 3.1

U.S. Crude Supplies (Base Case—No New Heavy Oil, MB/D)

(MB/D)				1990	1995	2000	2005	2010
DOMESTIC								
PADD	**Region**	**API**	**%S**					
I	East Light	51.6	0.26	30	20	10	--	--
II/IV	OK/WY	36.7	0.87	1,240	1,170	1,120	1,070	1,020
III	TX/LA	36.7	0.60	3,340	3,129	2,830	2,486	2,216
V	Alaska	27.8	1.12	1,773	1,490	1,070	660	400
V	California	18.3	1.33	973	948	923	898	873
	Total U.S.			**7,356**	**6,757**	**5,953**	**5,114**	**4,509**
			API	**32.3**	**32.3**	**32.4**	**32.5**	**32.5**
			%S	**0.87**	**0.87**	**0.86**	**0.86**	**0.85**
IMPORTS	**Region**	**API**	**%S**					
	N. America	29.8	1.29	643	640	640	640	640
	S. America	24.8	2.20	1,624	1,805	2,055	2,225	2,425
	Mid East	32.9	1.80	1,863	2,444	3,558	4,609	5,418
	Africa	35.4	0.17	1,205	1,100	900	900	900
	Europe	37.6	0.40	251	230	220	200	200
	Asia	39.5	0.10	281	280	230	210	210
	Total U.S.			**5,867**	**6,499**	**7,603**	**8,814**	**9.793**
			API	**31.4**	**31.2**	**31.0**	**31.1**	**31.2**
			%S	**1.38**	**1.46**	**1.63**	**1.63**	**1.65**
	TOTAL CRUDE			**13,223**	**13,256**	**13,556**	**13,928**	**14,302**
			API	**31.9**	**31.8**	**31.0**	**31.1**	**31.2**
			%S	**1.10**	**1.16**	**1.26**	**1.34**	**1.40**

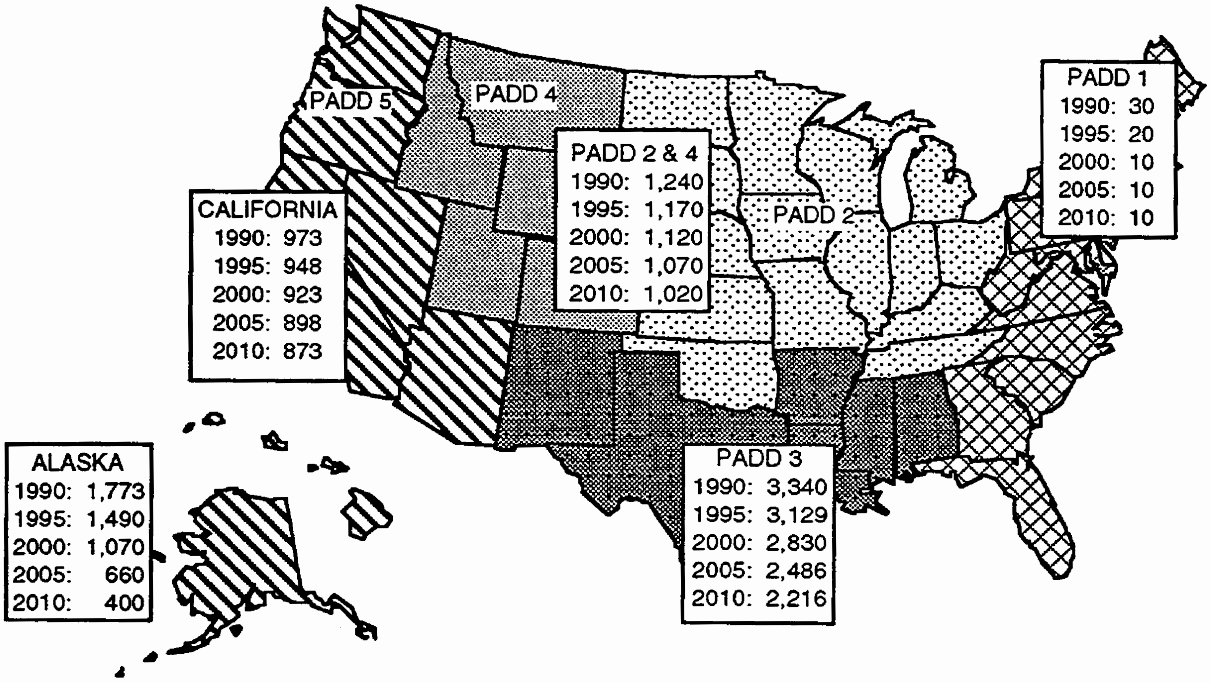


FIGURE 3.1 - Anticipated Domestic Crude Oil Production, 1990-2010, by PADD (PADD's 2 and 4 combined and PADD 5 split into Alaska and California).

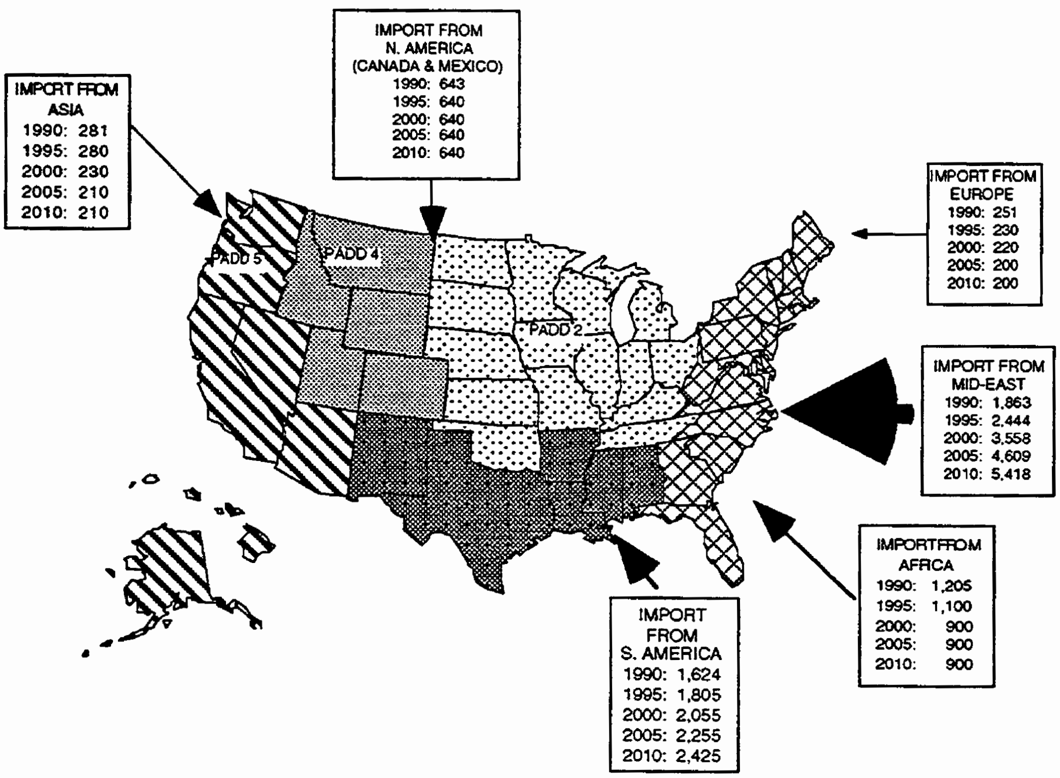


FIGURE 3.2 - Imported Oil (source and volume) for 1990-2010.

were balanced to meet the anticipated demand (total crude). Average oil quality is shown in Table 3.1 in the bottom rows for the composite mixture of crude oils to be processed in U.S. refineries.

Figure 3.1 shows schematically the trends in domestic oil production by PADD over the time frame from 1990 to 2010. The greatest percentage decrease in projected production is from Alaska (1,400 MB/D) which declines to the minimum carrying capacity (400 MB/D) of the Trans Alaska Pipeline System (TAPS). This assumption is based upon no new development of major fields on the North Slope or the interior of Alaska. The Gulf Coast experiences the second largest decline in production with the loss of 1,100 MB/D.

Figure 3.2 shows schematically the combination of domestic production and imports. Origin of the oil and anticipated volumes for each time period are shown. The largest increase in imported oil is from the Mid-east where an increase of 3,500 MB/D is anticipated. Imports from South America are anticipated to increase by 800 MB/D. Imports from Africa, Europe and Asia are anticipated to decline, whereas imports from Canada will remain nearly constant. A comparison of the overall percentage of domestic to imported crude oil from the base case was shown in Fig. 1.7 with the 50% import rate achieved before 1995. This transition is anticipated to occur earlier with lower oil prices.

To balance demand with domestic production and imports, significant volumes (MB/D) of oil are exchanged between PADDs as shown in Fig. 3.3 (EIA, 1991).

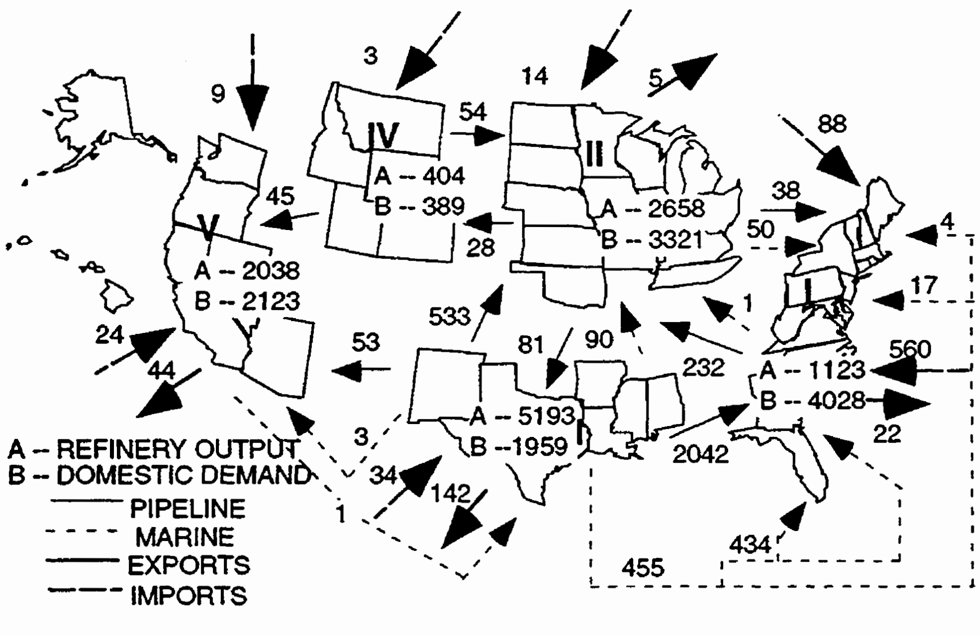


FIGURE 3.3 - Refinery output and domestic demand of refined product and the interchange of product between PADDs (EIA, 1991).

Discussion of Base Case

Between 1990 and 2010, crude oil consumption is anticipated to grow by 1,000 MB/D (13,233 MB/D in 1990 to 14,302 MB/D in 2010). This is based on a demand growth rate of 1%/year. Domestic oil production is anticipated to decline from 7,356 MB/D in 1990 to 4,509 MB/D in 2010, a loss of 2,847 MB/D or 39% of the 1990 production. Nearly 1,373 MB/D of that loss is from Alaska, and another 1,124 MB/D is from the Gulf Coast. The domestic production decline rate is projected to average 2%/year.

To make up the deficit, a major increase in imported oil is required. Most of the required imported oil will be from the Mid-east and the second largest supplier will be South America. The imported percentage of oil will increase from 44% in 1990 to >68% in 2010. Of the imported crude oil, the fraction supplied by the Mid-east will increase from 32% in 1990 to 55% in 2010 (1,863 MB/D to 5,418 MB/D). The fraction of imported crude oil supplied by Canada, Mexico and South American countries will decrease from 39% in 1990 to 31% in 2010.

The changes (in 5-year increments) for crude oil that will be refined are shown in a series of figures superimposed on the map of the U.S. for each of the ten refining areas considered in this study. The volumes (MB/D) are broken down as to light (>30° API gravity), medium (20°-30° API), and heavy oil (10°-20° API). Oil originating from domestic production (DOM) and imported (FOR) oil as well as the total refined oil in each gravity range is listed. The percentage of oil refined that is from domestic and imported sources is listed. Figures 3.4 through 3.8 are summaries of the U.S. refining crude oil feed for the base case—no new heavy oil. In Figure 3.4 (within the block designated refinery region 1) 13 MB/D of light oil is produced in the U.S., 767 MB/D of light oil, 405 MB/D of medium and 100 MB/D of heavy oil are imported. Refineries in region 1 process 1,285 MB/D.

The greatest impact on the U.S. petroleum industry has been the Clean Air Act (CAA) of 1976 and its amendments which caused a reduction in refinery emissions and vehicle emissions. Under the CAA, lead was phased out as an octane booster. The 1990 Amendment to the CAA requires even lower emission levels and significant improvement in product quality (gasoline and highway diesel). To meet product quality regulations on emissions from vehicles in air quality nonattainment areas, oxygenated fuels will constitute as much as 30 volume % of the gasoline market in most metropolitan areas of the U.S. Replacement of about 15% of the hydrocarbons in the gasoline pool with fuel oxygenates such as MTBE, TAME and ETBE to meet the reformulated fuel oxygen content requirements of 2.0 to 2.7 wt % will require large investments in a number of new units to produce these fuel oxygenates. This has created a huge demand on the capital available for refinery improvements. This capital is required for best available technology

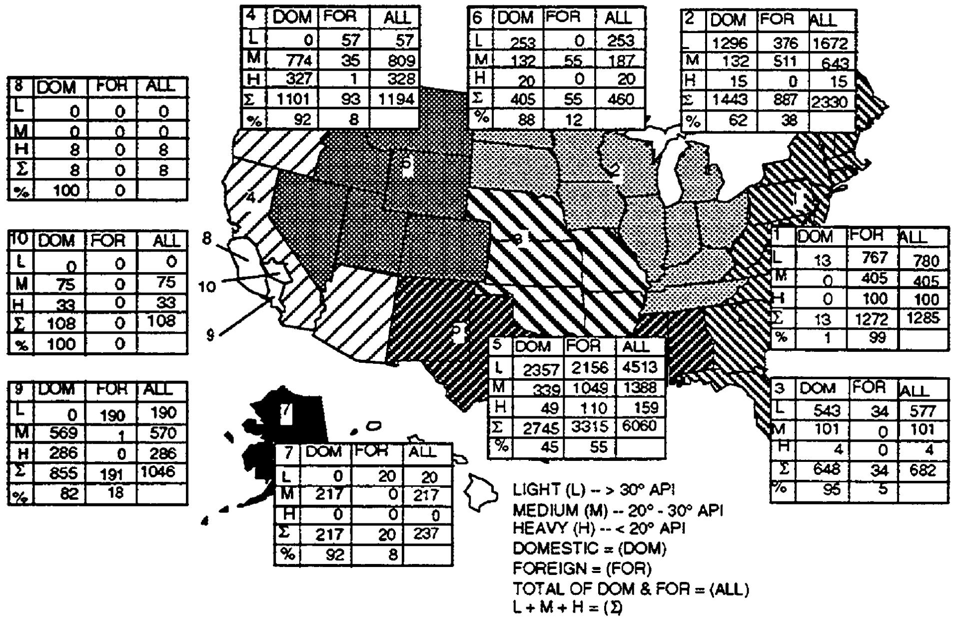


FIGURE 3.4 - Base case for 1990—no new heavy oil.

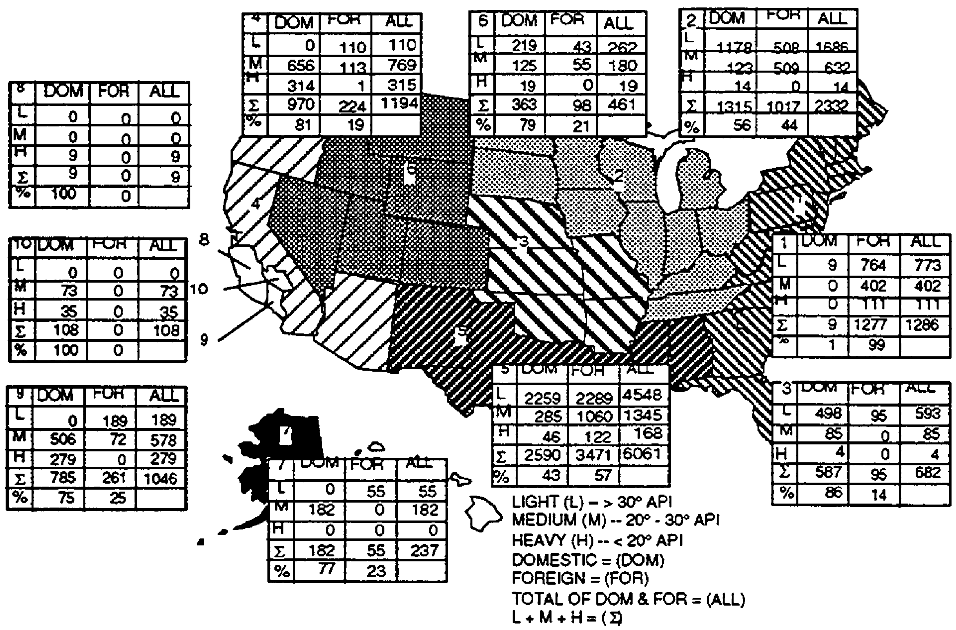
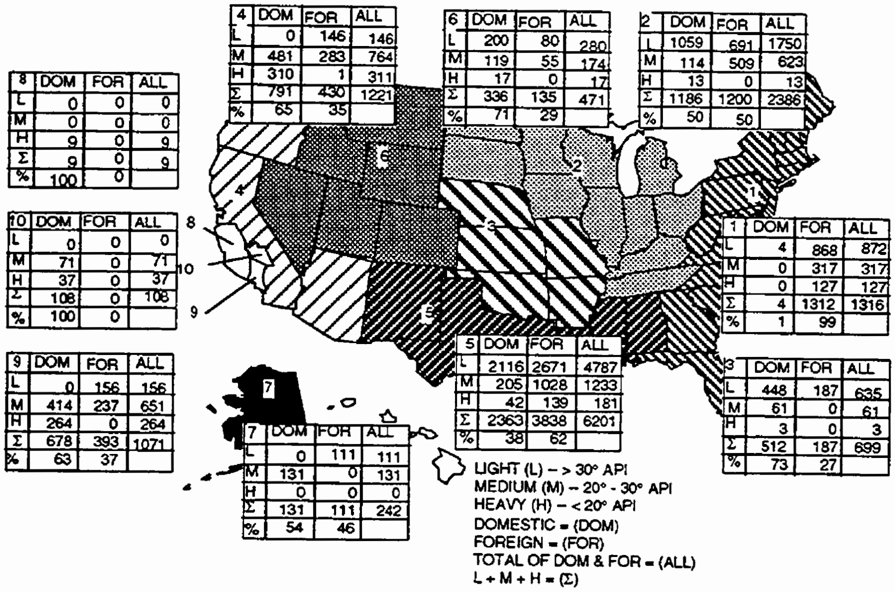


FIGURE 3.5 - Base case for 1995—no new heavy oil.



1	DOM	FOR	ALL
L	4	868	872
M	0	317	317
H	0	127	127
Σ	4	1312	1316
%	1	99	

2	DOM	FOR	ALL
L	1059	691	1750
M	114	509	623
H	13	0	13
Σ	1186	1200	2386
%	50	50	

3	DOM	FOR	ALL
L	448	187	635
M	61	0	61
H	3	0	3
Σ	512	187	699
%	73	27	

4	DOM	FOR	ALL
L	0	146	146
M	481	283	764
H	310	1	311
Σ	791	430	1221
%	65	35	

5	DOM	FOR	ALL
L	2116	2671	4787
M	205	1028	1233
H	42	139	181
Σ	2363	3838	6201
%	38	62	

6	DOM	FOR	ALL
L	200	80	280
M	119	55	174
H	17	0	17
Σ	336	135	471
%	71	29	

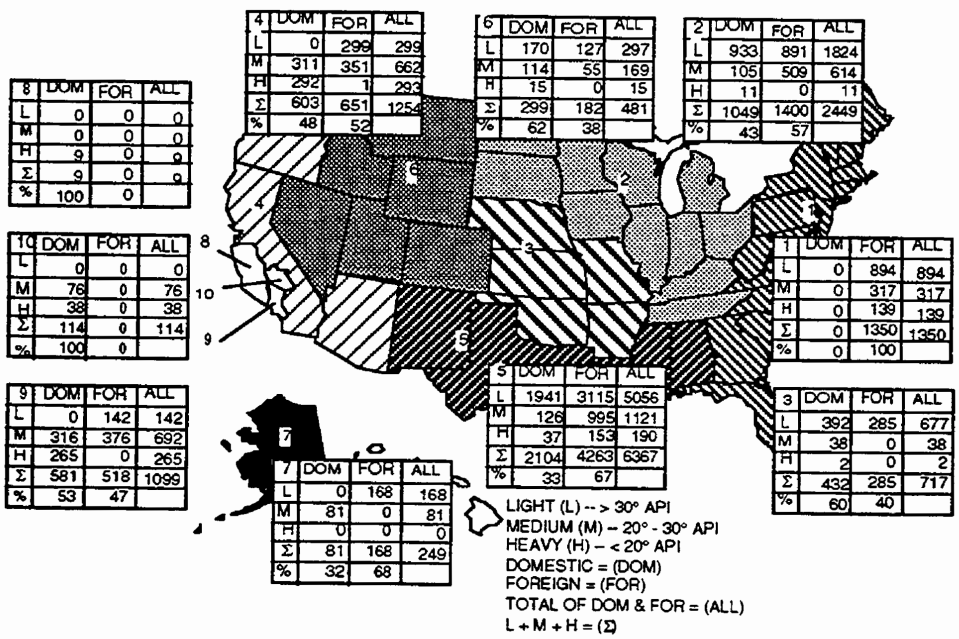
7	DOM	FOR	ALL
L	0	111	111
M	131	0	131
H	0	0	0
Σ	131	111	242
%	54	46	

8	DOM	FOR	ALL
L	0	0	0
M	0	0	0
H	9	0	9
Σ	9	0	9
%	100	0	

9	DOM	FOR	ALL
L	0	156	156
M	414	237	651
H	264	0	264
Σ	678	393	1071
%	63	37	

10	DOM	FOR	ALL
L	0	0	0
M	71	0	71
H	37	0	37
Σ	108	0	108
%	100	0	

FIGURE 3.6 - Base case for 2000—no new heavy oil.



1	DOM	FOR	ALL
L	0	894	894
M	0	317	317
H	0	139	139
Σ	0	1350	1350
%	0	100	

2	DOM	FOR	ALL
L	933	891	1824
M	105	509	614
H	11	0	11
Σ	1049	1400	2449
%	43	57	

3	DOM	FOR	ALL
L	392	285	677
M	38	0	38
H	2	0	2
Σ	432	285	717
%	60	40	

4	DOM	FOR	ALL
L	0	299	299
M	311	351	662
H	292	1	293
Σ	603	651	1254
%	48	52	

5	DOM	FOR	ALL
L	1941	3115	5056
M	126	995	1121
H	37	153	190
Σ	2104	4263	6367
%	33	67	

6	DOM	FOR	ALL
L	170	127	297
M	114	55	169
H	15	0	15
Σ	299	182	481
%	62	38	

7	DOM	FOR	ALL
L	0	168	168
M	81	0	81
H	0	0	0
Σ	81	168	249
%	32	68	

8	DOM	FOR	ALL
L	0	0	0
M	0	0	0
H	9	0	9
Σ	9	0	9
%	100	0	

9	DOM	FOR	ALL
L	0	142	142
M	316	376	692
H	265	0	265
Σ	581	518	1099
%	53	47	

10	DOM	FOR	ALL
L	0	0	0
M	76	0	76
H	38	0	38
Σ	114	0	114
%	100	0	

FIGURE 3.7 - Base case for 2005—no new heavy oil.

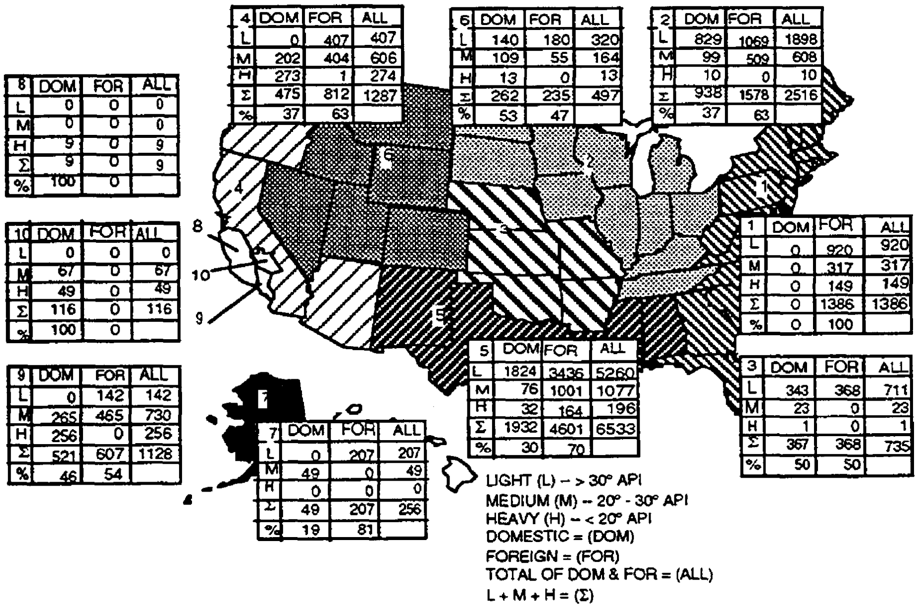


FIGURE 3.8 - Base case for 2010—no new heavy oil.

equipment to meet the CAA and EPA standards, if the refiner wants to stay in the fuel marketing business. Smaller refiners have a temporary delay in implementation of some of the requirements of the CAA amendment regulations. Many small refineries will close in the latter half of the 1990s (when these exemptions expire) because they cannot meet the requirements and still make an adequate return on investment.

The volumes of additional (new production) heavy oil considered in this study (300 MB/D and 900 MB/D) amount to only 2% for 300 MB/D and 6% for 900 MB/D of the year 2010's total crude oil demand of 14,302 MB/D. However, when considering these small oil volumes relative to the base case (no new heavy oil) domestic production of 4,509 MB/D in the year 2010, the percentages are not so small, 6.6% for 300 MB/D and 20% for 900 MB/D. For domestic production only in the year 2010 and adjusting for the additional current (750 MB/D, 1992) domestic production, the percentage of heavy oil in the total U.S. production increases to 25% for 300 MB/D and 33.3% for 900 MB/D. These figures do not reflect the use of small amounts of light condensate (< 100 MB/D) added to the refinery pool to meet projected demand. Consequently, actual percentages will be slightly less.

In the base case, average API gravity of the refinery throughput declines slightly from 32° to 31° API. Sulfur content climbs from 1.1% to 1.4%, which is mainly due to significant increases in the volume of higher sulfur Mid-east imports. In NIPER's previous analysis, it was found that each 1° API drop in crude quality resulted in an increase of difficult to process vacuum bottoms of about 2% (Olsen and Ramzel, 1991). Therefore, the small decrease in the base case is not of significance. It is only mentioned here because it will be an important point to be considered when looking at the low and high case heavy oil scenarios. Another important point to keep in mind is the large investments made by the refining industry in the 1980s (especially the early 1980s) in "bottom of the barrel conversion" capacity. As Bonner and Moore note in volume 1, "...thermal conversion to distillation capacity ratio(s)...nearly doubled, providing...necessary operational flexibility to address...demand within the prevailing regulatory constraints in a profitable manner." NIPER's previous refinery analysis verified double digit increases in refinery heavy ends conversion capacity during this time period (Olsen and Ramzel, 1991).

NIPER's refinery analysis could only document about 900 MB/D of heavy oil charged to U.S. refineries in 1990 (750 MB/D of domestic production and 150 MB/D of imports). This was 6.6% of the refinery throughput in 1990. Documentation of imported heavy crudes never rose much above 4%. However, when NIPER looked at crudes < 25° API, the percentages were about 28% in the early 1980s and had decreased to 17% in 1990. It is believed that much of the medium crudes being imported to the U.S. are diluted heavy crude oil. Thus, the "actual" heavy crude charge to U.S. refineries is probably considerably higher than reported. Private interviews indicated that many central U.S. refineries can handle 15 to 18% heavy crude charge.

When comparing the 1990 no new heavy oil base case to the 2010 no new heavy oil base case, heavy oil throughput to refineries stays flat (953 MB/D to 957 MB/D); medium oil falls from 4,395 MB/D to 3,641 MB/D; and light oil rises significantly from 8,062 MB/D to 9,865 MB/D. The light oil increase is almost exclusively foreign imports.

EFFECT OF AN ADDITIONAL 300 MB/D OF DOMESTIC HEAVY OIL ON U.S. REFINERIES

Discussion of Low Volume Heavy Oil Case

A picture of the low volume heavy oil production/refining scenario addition of 300 MB/D of heavy oil to the current 750 MB/D of heavy oil, can be attained by comparing the 2010 base case to the 2010 low volume case refinery throughput. Although it has taken approximately 30 years for thermal (steam) to add approximately 500 MB/D to California heavy oil production, the addition of 300 MB/D in 20 years as projected in Table 2.4 is achievable (Olsen, 1993). The results of the 300 MB/D addition of heavy oil are shown for each of the 10 refining areas for the years 1995 to 2010 (by 5-year increments), in Figs. 3.9 through 3.12 in MB/D. Compared to the 2010 base case, heavy oil throughput increases 400 MB/D (957 MB/D to 1,356 MB/D); medium oil stays the same at 3,641 MB/D; and light oil decreases from 9,865 MB/D to 9,466 MB/D.

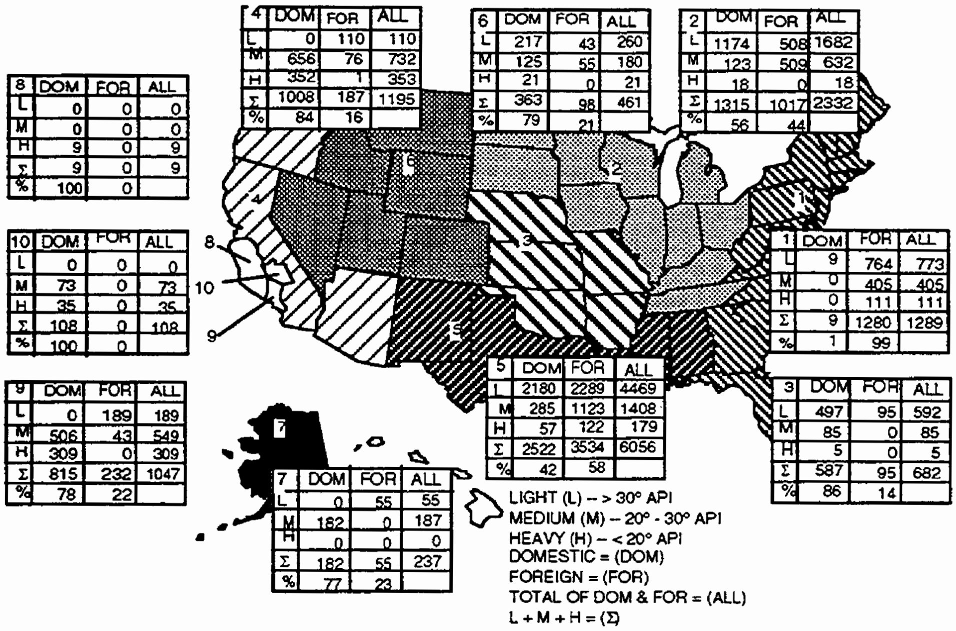


FIGURE 3.9 - **Distribution of light, medium and heavy oil by region with addition of heavy oil, maximum 300 MB/D for 1995 (low case scenario).**

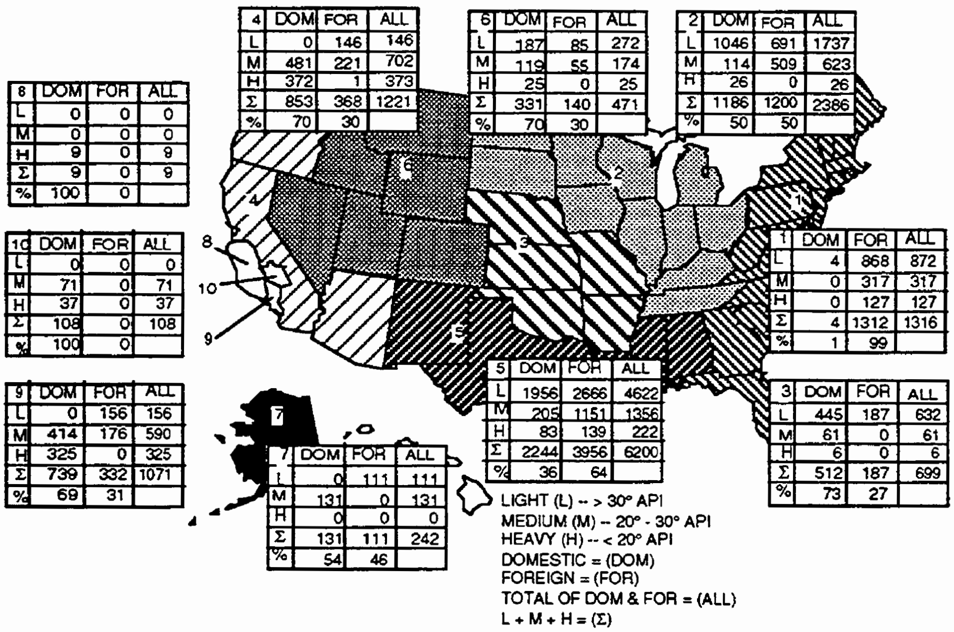


FIGURE 3.10 - **Distribution of light, medium and heavy oil by region with addition of heavy oil, maximum 300 MB/D for 2000 (low case scenario).**

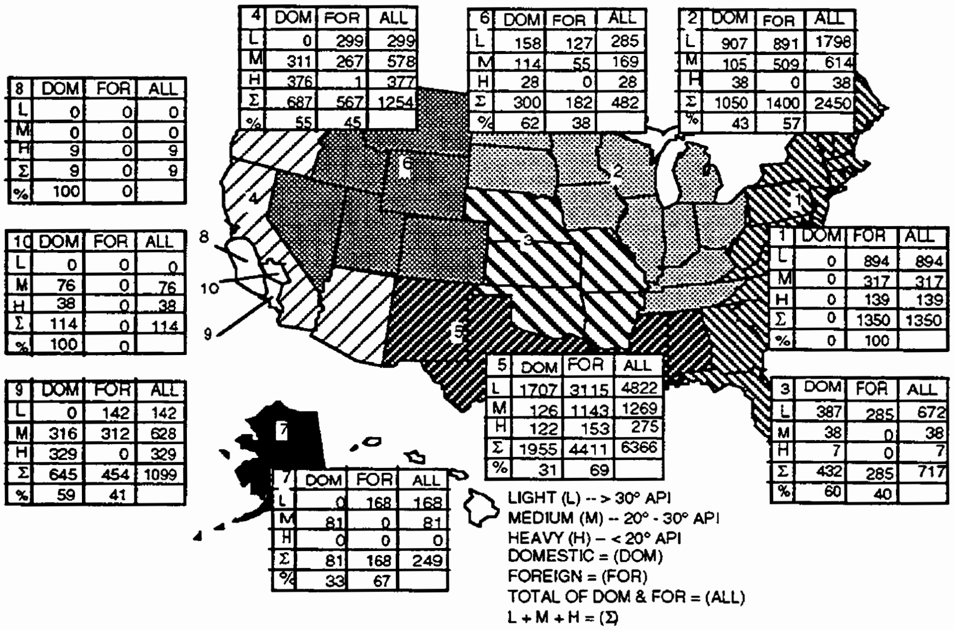


FIGURE 3.11 - **Distribution of light, medium and heavy oil by region with addition of heavy oil, maximum 300 MB/D for 2005 (low case scenario).**

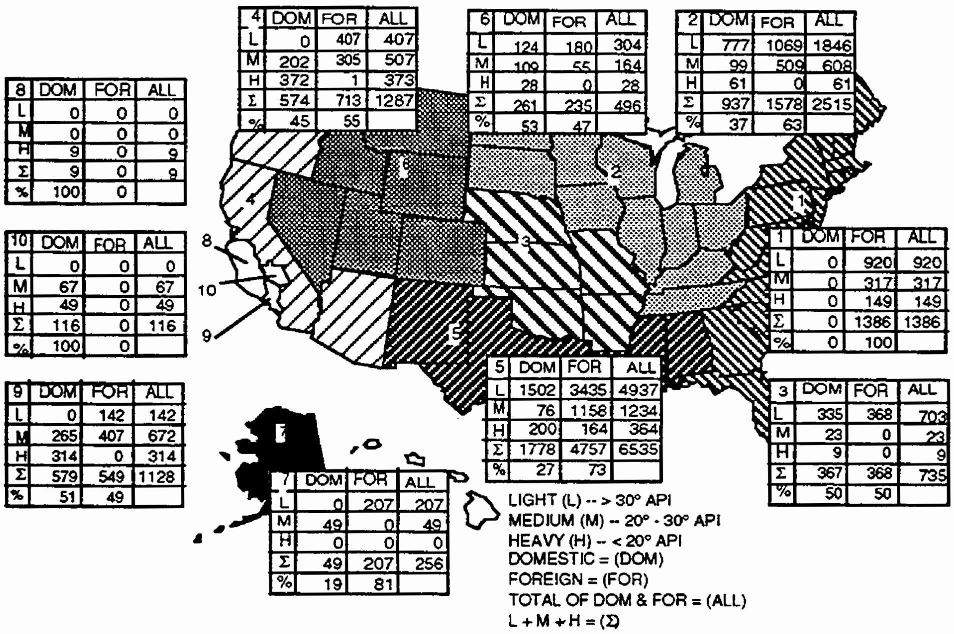


FIGURE 3.12 - **Distribution of light, medium and heavy oil by region with addition of heavy oil, maximum 300 MB/D for 2010 (low case scenario).**

The increase in heavy oil is equivalent to the decrease in light oil. The light oil decrease has chiefly two components: (1) Mid-east high sulfur light, and (2) some domestic light condensate. The net effect at the refinery is to replace a loss in medium crude with a heavy crude diluted with light crude (i.e., "another medium").

EFFECT OF AN ADDITIONAL 900 MB/D OF DOMESTIC HEAVY OIL ON U.S. REFINERIES

Discussion of High Volume Heavy Oil Case

A picture of the high volume heavy oil production/refining scenario, addition of 900 MB/D of heavy oil to the current 750 MB/D of heavy oil, can be attained by comparing the 2005 and 2010 years with the base case to the 2010 as shown in Figs. 3.13 and 3.14 in MB/D. Compared to the 2010 low case scenario, the volume of heavy oil refined increases from 1,356 MB/D to 1,955 MB/D (about 600 MB/D); medium oil volume remains constant 3,672 MB/D vs. 3,641 MB/D; and light oil volume decreases from 9,466 MB/D to 8,837 MB/D (about 630 MB/D).

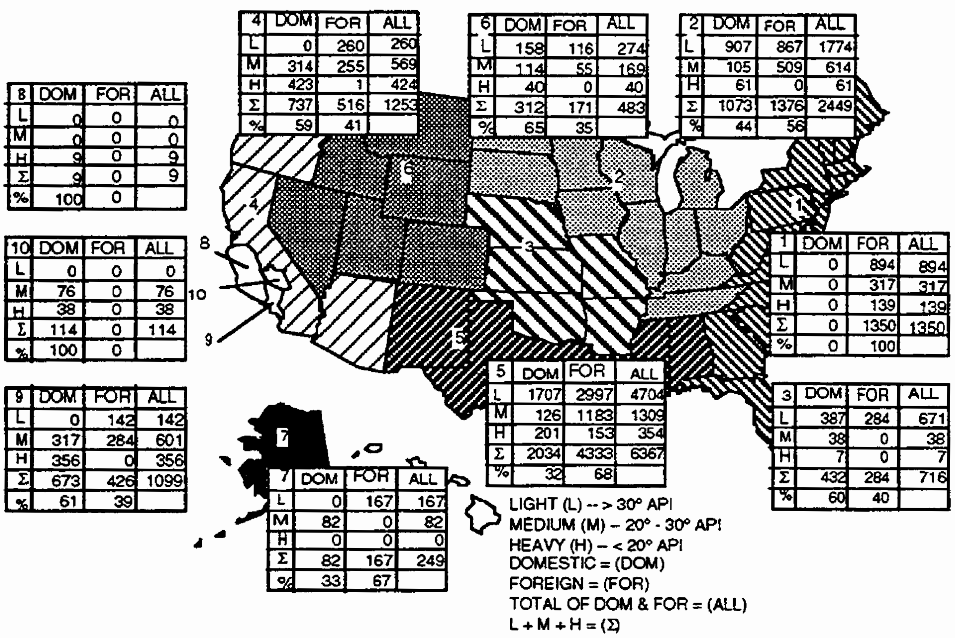


FIGURE 3.13 - Distribution of light, medium and heavy oil by region with addition of heavy oil, maximum 900 MB/D for 2005 (high case scenario).

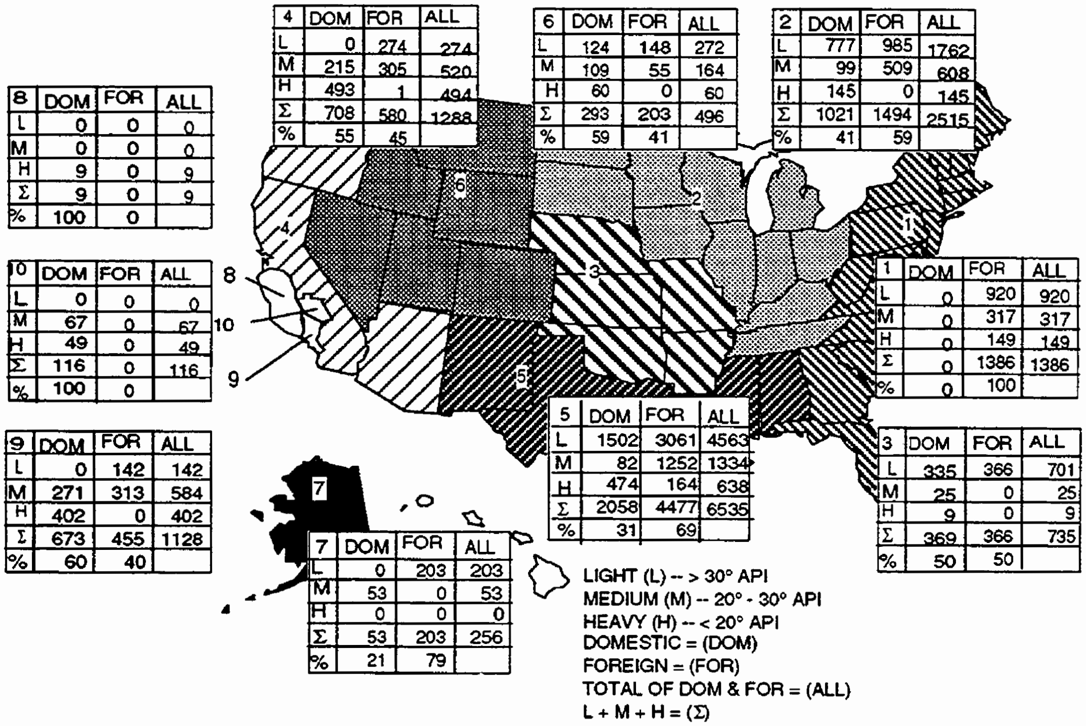


FIGURE 3.14 - Distribution of light, medium and heavy oil by region with addition of heavy oil, maximum 900 MB/D for 2010 (high case scenario).

Comparing the heavy oil as a percent of the refinery crude charge from scenario to scenario, heavy oil accounts for 7.1% of the refinery throughput in the 1990 no new heavy oil base case scenario, Fig. 3.4), drops to 6.6% in the 2010 (no new heavy oil base case scenario, Fig. 3.8), increases to 9.4% in the 2010 low volume case scenario (Fig. 3.12), and increases to 13.5% in the 2010 high volume heavy oil scenario (Fig. 3.14). On the surface, these higher percentages seem foreboding (doubling of the volume of heavy oil refined) and are somewhat alarming. However, it must be remembered that the "documented" heavy oil charge understates actual heavy oil charge to the refineries due to foreign medium crudes being "diluted heavy crude." It is important to look at the effects on the overall API gravity and sulfur content shifts of the total crude charge in regions most affected by these scenarios as detailed in the B&M reports in the appendices.

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Chapter 4

PROJECTIONS AND COSTS BY REFINING AREA

PROJECTED U. S. REFINING AREA UPGRADES TO ACCOMMODATE ADDITIONAL DOMESTIC HEAVY OIL

Projected Cost of U.S. Heavy Oil Refining Scenarios

Based on the LP analyses of proposed incremental, new domestic heavy oil production, (300 MB/D, low or 900 MB/D, high volume), estimates of the impact on the U.S. refining industry were made. Because this refining feasibility study essentially substituted "diluted heavy" crude for imported medium crudes and because of the anticipated huge increase in imported crude oil charged (Mid-east oil), the incremental costs associated with both the low and high sulfur Gulf Coast crudes and both the low and high volume heavy oil production scenarios, the costs were not substantially different—about $7 billion in all cases, Tables 4.1 through 4.4. Table 4.1 shows a summary (in 2010) of the composite refining units (in MBCD) and their cost (MM$) to accommodate the low volume (300 MB/D) of additional domestic heavy oil. No expenditure is anticipated for area 7. Construction of delayed coking capacity (page 10 of Executive Summary) is only part of the facilities and cost required to process this incremental domestic heavy oil. Table 4.2 shows required expenditures in 5-year increments. Table 4.3 shows the cost for upgrading refineries vs. meeting CAA requirements.

TABLE 4.1 Summary of Units and Cost for New Refinery Construction Required by the Year 2010 to Accommodate 300 MB/D of Additional Domestic Heavy Oil

				Size of Units (New Facilities, MBCD)					
Refining Area	**1**	**2 & 3**	**4**	**5**	**6**	**7**	**9**	**8 & 10**	**TOTAL**
Crude Distillation	101.0	262.0	93.0	622.0	71.0	-	281.0	9.0	1,439.0
Vacuum Distillation	67.5	216.4	64.8	570.0	69.8	-	260.6	21.6	1,270.7
Coking	17.4	87.0	-	99.6	25.8	-	-	-	229.8
Oxygenates	165.3	286.9	123.5	1,118.2	-	-	370.2	16.6	2,080.7
Isomerization	-	-	-	-	37.6	-	-	-	37.6
Cat Cracking						-	127.6	6.4	134.0
Hydrocracking						-	70.7	22.8	93.5
Alkylation					7.7	-	100.9	6.5	115.1
Hydrotreating						-	16.7	-	16.7
Plan Utilities						-	-	-	-
Total	351.2	852.3	281.3	2,409.8	211.9	-	1,227.7	82.9	5,417.1
				Cost (New Facilities, MM$)					
Refining Area	**1**	**2 & 3**	**4**	**5**	**6**	**7**	**9**	**8 & 10**	**TOTAL**
Crude Distillation	56.5	105.1	53.6	184.3	45.0	-	110.0	11.7	566.2
Vacuum Distillation	46.2	110.8	44.8	229.0	47.4	-	127.3	19.7	625.2
Coking	35.8	87.1	-	95.1	113.6	-	-	-	331.6
Oxygenates	355.8	519.3	315.4	1,162.9	-	-	623.5	87.5	3,064.4
Isomerization					107.1	-	-	-	107.1
Cat Cracking						-	278.9	39.6	318.5
Hydrocracking						-	242.2	119.0	361.2
Alkylation					13.9	-	254.5	39.5	307.9
Hydrotreating						-	24.4	-	24.4
Plan Utilities	131.0	253.1	124.6	295.6	97.9	-	350.8	91.2	1,344.2
Total	625.3	1,075.4	538.4	1,966.9	424.9	-	2,011.6	408.2	7,051.7

TABLE 4.2 Total Investment in Facilities—Low Volume (300 MB/D) Heavy Oil Refinery Upgrade Costs (MM$)

Refining Area	1995	2000	2005	2010
1	23	91	558	625
2 & 3	57	250	892	1,075
4	3	91	482	538
5	848	890	1,724	1,967
6	301	332	417	425
7	–	–	–	–
9	975	1,511	2,026	2,012
8 & 10	177	227	371	408
Total	$2,384	$3,392	$6,470	$7,050

TABLE 4.3 Total Investment in Facilities—Low Volume Heavy Oil Refinery Upgrade Costs vs. Clean Air Act Costs (MM$)

Refining Area	2000 Heavy Crude	2000 CAA	2000 Total Investment	2010 Heavy Crude	2010 CAA	2010 Total Investment
1	89	2	91	248	377	625
2 & 3	249	1	250	545	530	1,075
4	86	5	91	295	243	538
5	393	497	890	743	1,224	1,967
6	324	8	332	414	11	425
7	–	–	–	–	–	–
9	448	1,063	1,511	1,618	394	2,012
8 & 10	138	89	227	301	107	408
Total	$1,727	$1,665	$3,392	$4,164	$2,886	$7,050

TABLE 4.4 - Total Investment in Facilities—High vs. Low Volume Refinery Upgrade Costs (MM$)

Refining Area	2005 High	2005 Low	Difference	2010 High	2010 Low	Difference
1	558	558	–	625	625	–
2 & 3	892	892	–	1,080	1,075	5
4	488	482	6	616	538	78
5	1,725	1,724	–	2,007	1,967	40
6	418	417	1	454	425	29
7	–	–	–	–	–	–
9	2,043	2,026	17	2,063	2,012	51
8 & 10	371	371	--	408	408	--
Total	$6,494	$6,470	$24	$7,253	$7,050	$203

Regional API and Sulfur Content Shifts

Sulfur content increases are minimized in the analysis because high sulfur Mid-east light crude is replaced by a "not so bad" low sulfur Gulf Coast crude (i.e., 19.8° API, 0.6 wt % sulfur). An additional study has been conducted by (Appendix III) using a lower gravity, high sulfur (18.2° API, 2.8 wt % sulfur) Gulf Coast crude. The total refining investment required $7.253 billion by the year 2010 (high volume production scenario, 900 MB/D, Table 4.4) and will increase by $110 million with this compositional change in Gulf Coast heavy crude oil.

Regions most in need of capital investment were regions 2, 3, 5, and 9 in all cases. These regions account for about 70% of the total of $7 billion. Only regions 2, 3, and 5 changed when going to a higher sulfur Gulf Coast crude.

When incremental costs are divided between those costs associated with processing additional heavy crude and those costs associated with meeting the 1990 amendments to the Clean Air Act, differences among the four regions most affected are apparent, see Table 4.3. Regions 2 and 3, which were considered together in the analysis, split costs about 50-50. About 60% of the incremental costs in region 5 are associated with meeting the CAA, while about 80% of the incremental costs in region 9 are associated with processing additional heavy crude. The reasons for the difference between region 5 and 9 are twofold: (1) Region 9 is in California where strict environmental regulations have been in place for some time, and the costs to meet these have already been largely incurred, and (2) California is already running significant amounts of heavy crude through its refineries, and in order to process more, it would have to make some significant investments. Region 5, on the other hand, has not had to meet such stringent environmental regulations, and its refineries do not process such large amounts of heavy crude as California. However, as was noted earlier, significant thermal conversion capacity that is not presently being used in region 5 was built in the 1980s, especially in the tight oil market of the early 1980s. Therefore, region 5 ends up spending more to meet the CAA than it does to process more heavy crude.

It is imperative to note some costs and items are <u>not</u> considered by the analysis. First, <u>all</u> costs associated with reformulated fuels and with refineries meeting the requirements of the 1990 amendments to the Clean Air Act <u>are not</u> considered. Only those <u>incremental</u> costs associated with <u>additional</u> heavy oil processing are considered. These costs are largely mitigated by blending domestic heavy oil with imported light oil to replace a loss in medium crude and by a large increase in imported light crude oil charged relative to the 1990 base case. Second, production costs associated with bringing the additional heavy oil on-line are not considered in this refining report. Third, costs associated with waste water treatment were not specifically addressed. Newly implemented regulations on waste water treatment could increase costs. Fourth, infrastructure costs to the refining and petroleum industry to handle the large increase in imports were not considered—such items as new foreign oil loading facilities, port facilities, storage facilities, pipeline additions and pipeline flow reversal costs, product pipeline additions, or costs associated with possible product pipeline segregation.

The three regions most affected by the addition of heavy oil under the heavy oil production scenarios and that are of most significance to the overall picture are regions 4, 5 and 9. In the low volume heavy oil case, API gravity in region 4 goes up slightly, region 5 goes from 33° to 32° API, and region 9 goes from 26° to 24° API gravity. In the high volume heavy case scenario, API gravity in region 4 goes from 24° to 23° API, region 5 from 33° to 31° API, and region 9 from 26° to 23° API. In no region is a shift greater than 4° to 5° API downward in either scenario. The regions most affected in this regard are regions 6, 8 and 10; all minor in terms of total refining capacity. Region 6, since it has little heavy oil refining capacity, will be the region most affected by this relatively large downward shift. Regions 4, 8, 9, and 10 are all part of the California heavy oil refinery area and can accommodate these decreases in crude API. Overall, the decrease in total crude quality charged to U.S. refineries in terms of API decrease and sulfur content increase is tolerable to levels under the two heavy oil production/refining scenarios that are considered in this study.

Future of Heavy Oil Refining

Currently, California (Regions 4, 8, 9, and 10) produces and refines most of the Nation's heavy oil. Heavy oil accounts for about 28% of the refinery throughput in these regions. This is an extremely high percentage relative to other regions of the U.S. In those regions (e.g., the Gulf Coast and Mid-west), 15 to 18% heavy oil charge to a refinery configured to process more heavy oil is probably the current maximum (Olsen and Ramzel, 1991). In California, where most refineries are configured to handle heavy oil, 28% heavy oil charge is a moderately high level.

NIPER's previous heavy oil refining study (Olsen and Ramzel, 1991) indicated two areas in the lower 48 states (outside of California) with a sufficiently high heavy oil resource base to be considered as future heavy oil production and processing centers—Wyoming and the Gulf Coast states. The Gulf Coast states have about 50% of the Nation's refining capacity (about 50% of the Nation's heavy oil processing capability), but only 25% of the Nation's asphalt capacity. Unfortunately, Wyoming and the Rocky Mountain states have little refining capacity; thus, it was abandoned as a viable alternative. Alaska with its large heavy oil resource was considered, but was excluded due to high oil production/transportation costs, and because of the high environmental, processing, and marketing restraints of Alaska's most likely marketplace for heavy oil, California.

Summary

In order for domestic refineries to take additional heavy oil, three things must occur: (1) The additional heavy oil will have to be produced (2) the heavy oil must be priced at the refinery gate at a cost sufficiently low to overcome the operational margin disparity (economics) to the refiner between light crude oil and heavy crude oil, and (3) the refining infracstructure (bottoms conversion units as described in this report) must be constructed, but this must occur in increasingly tight and competitive capital, investment, and credit markets with widely divergent rates of return on investment. This study addressed cost of required refining units; however, the scope of the problem of the feasibility of increasing domestic heavy oil production is larger than that which was addressed.

BONNER & MOORE PROJECT #MS91-582

APPENDICES

Appendix I

Volume I

REFINERY EXPANSION EVALUATION

FOR U.S. HEAVY OIL RECOVERY

Assessment of Market Capacity
for Specific Regions with Predefined Increases
in Heavy Oil
for the Years 1992 through 2010

VOLUME I

Performed for

the National Institute for Petroleum Research
Bartlesville, Oklahoma

April 1992

Bonner & Moore Project #MS91-582

REFINERY EXPANSION EVALUATION FOR U.S. HEAVY OIL RECOVERY

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SENSITIVITY ANALYSIS

CONCLUSIONS

CONCLUSIONS

- The U.S. demand for petroleum products is anticipated to grow at a conservative 1% per year during the planning period. Most of the growth will be in the transportation fuel sector.

- Despite all efforts by OPEC members to expand their crude production capabilities, Middle Eastern producers will be the main source of incremental supplies to the U.S. refiners during the next twenty years. Other sources will contribute with more modest volumes.

- A 2% per year decline in domestic crude supplies, mainly in terms of Alaska North Slope (ANS) and Midwest light sweet crude, will increase the dependency of the refineries to crude imports. The "more than fifty percent threshold" of imports to domestic crude supplies will probably occur by the year 1996 (assuming a continued relentless opposition to produce in "new" areas).

- Loss of ANS production will significantly affect the current U.S. crude supply logistics and cause an additional cost burden on refined product prices.

    - Idle West Coast refining capacity will require crudes otherwise destined to other areas in order to meet consumer demands.

    - Midwestern inland refineries will depend more on import crudes to make up their crude shortfall. The current pipeline system will significantly reverse its traditional flow patterns.

- In order to process the incremental domestic heavy oil at both the High (930 MB/D) and Low (300 MB/D) production rate scenarios estimated by the National Institute for Petroleum and Energy Research (NIPER), the following bottoms conversion capacity (delayed coking) must be constructed:

CONVERSION CAPACITY BY 2010

	MB/D		
Region	**High**	**Low**	**▲**
1	17	17	--
2 & 3	90	87	3
4	11	--	11
5	162	100	62
6	30	26	4
Total	**310**	**230**	**80**

- In either, or both, heavy oil production rate scenarios, in a twenty year span, the U.S. refining industry could be faced with capital expenditures in the 7 billion dollar range, of which approximately 1 billion would be required to maintain operable the existing distillation capacity, another 1 billion dollars to build the necessary conversion capacity to process the additional domestic heavy oils **and** crude imports, and the balance to comply with the Amendments to the Clean Air Act (CAA) and quality treatment of intermediate streams.

  Investment costs attributable directly to compliance with the regulation of the CAA are estimated at 3 billion dollars.

SECTION 1

CONVERSION CAPACITY REQUIREMENTS
LOW HEAVY OIL PROJECTIONS

BACKGROUND

Recovery of heavy crude oils (defined in this study as less than 20 degrees API) by enhanced oil recovery (EOR) technology accounts for a nominal volume of the world crude production. However, in some countries, EOR production is an important contribution to the overall crude availability. In the United States, at the end of 1990, heavy crude oil originating from EOR projects, predominantly in California, was slightly under 700 MB/D.

Worldwide, there has been little increase in EOR crude production because of ample availabilities of less costly and qualitatively more desirable crudes originating from areas with low production costs. Furthermore, high crude prices are crucial for justifying EOR projects since some of the technology (steamflooding) utilizes nearly 20% of the production as fuel for steam generation. This, coupled with strict environmental regulations and other technological considerations, emphasizes the need for sound economic incentives to allow for the required capital outlay.

There are two areas identified in the United States as most promising for additional heavy oil production outside of California: the northern Rocky Mountain states (mainly Wyoming) and the Gulf states (principally Texas and Louisiana). The development of these resources requires significant economic investment, and without meaningful incentives expansion of domestic heavy oil to areas outside current producing areas will be limited.

Several approaches could be taken by the U.S. refining industry to process and upgrade an increased supply of heavy crude oils (less than 20 degrees API). Among the available commercially proven processes are delayed coking, flexicoking, and resid hydrocracking. The first two utilize, primarily, the carbon-rejection technology to upgrade bitumen, while the latter is based on hydrogen-addition technology.

Delayed coking is the lowest investment, and is a proven, environmentally acceptable technique for upgrading heavy crudes. Approximately 60% of the vacuum resid feedstock is converted to liquid products, requiring further downstream hydrotreating before they are used as components for commercial products. Product coke, which at times contains up to 5 wt % sulphur, depending on the sulphur content of the crude, would be disposed of as fuel-grade coke. Better quality coke (less than 3 wt % sulphur) has an outlet in the metallurgical industry which pays a price premium over the fuel coke market.

Delayed coking is the preferred process for heavy oil conversion in this study.

OBJECTIVE AND SCOPE

Bonner & Moore has been subcontracted by NIPER to evaluate the necessary refinery expansion to accommodate incremental production of domestic heavy oils in ten proposed regions of the United States.

The analytical procedure to answer the key question, "If domestic production is increased between now and the year 2010, what necessary adjustments can the U.S. refinery industry make to process the incremental volume?" involves developing the following:

- A U.S. petroleum supply demand outlook in accordance with the prevailing world petroleum market environment anticipated during the next twenty years. Forecast of the associated crude and product prices where the U.S. refined product price outlook is in compliance with the regulatory quality requirements of the 1990 Amendments to the Clean Air Act (CAA).

- A U.S. refinery industry profile to fully describe the sources and crude intake qualities used by the existing U.S. operable refining capacity to meet consumer demand for refined products. The 1990 data has been designated as the "Base Case" for model validation purposes.

- Consistent with the proposed refining regions, the development of ten linear programming (LP) models, with the objective of estimating the necessary investment levels in conversion capacity to accommodate the forecasted incremental U.S. domestic heavy oil production. Also, in accordance with the petroleum market outlook, a forecasted crude supply was performed assuming no new incremental domestic heavy oils.

A detailed analysis of each one of these facets of the study are described in the second volume of this report.

HIGHLIGHTS FROM VOLUME II

Base Case Market Assessment

The U.S. market for petroleum products will experience a modest yearly demand growth of about 1% during the balance of this decade. Most of the growth will be in the transportation fuels sector, although motor gasolines are not viewed as the major contributor because of moderate population growth and improvement in the vehicle fleet mpg ratings. Jet fuels and environmentally acceptable automotive diesel are the most accountable for the contemplated growth. On the other hand, demand for residual boiler fuels are envisioned to decline, or at best remain stagnant, as competition from alternate fuels continue to make a dent in the market.

Crude supplies to U.S. refineries will increase their dependency on imports as domestic production declines about 2% per year. The bulk of the loss in domestic production is mainly in terms of ANS crude (80 to 100 MB/D per year), along with moderate declines in other light crudes from the Gulf and Midwest producing areas. The "over the 50% import dependency" threshold is foreseen to occur in 1996.

Crude prices are forecasted to follow an upward trend in current and constant 1990 dollars over the planning period. This assumption, supported on projections of the world supply/demand balance, which, based on moderate demand growth rates and realistic production profiles, results in increasing capacity utilization rates for OPEC, the incremental world crude producer and price setter.

The forecasted crude price is not entirely linear, as we are projecting a price hike in 1998 as OPEC's capacity utilization temporarily increases near 90%. As in the past, we anticipate that this particular market environment will set the stage for a politically-motivated (versus a supply constrained) price spike that will be temporary in nature due to the self-correcting reaction of demand declining.

Refined product prices are expected to follow a trend similar to crude prices. Light products are forecasted to rise faster than crude due to increasing demands, and the lightening of the United States and world refined product slate.

The prices in our forecast meet the requirements of the CAA, and for distillate that meets the new low sulphur diesel specifications. Spot U.S. residual fuel prices are also expected to trend upwards with crude prices, but at a lower rate due to our projection of low U.S. and world demand growth rates for residual fuels and a declining market share.

Based on our crude and refined products forecast, we are projecting U.S. refining margins to average close to $2.00 per barrel during most of the planning period.

Industry Profile

The single most important market-driven events to impact U.S. refineries, to date (without significant disruptions), have been the motor gasoline lead phasedown and the need to accommodate declining consumption of residual fuels for electric power generation.

Significant investments took place for the production of high octane components, to replace lead quality stabilization, and "bottom of the barrel conversion" during the last ten years. As a result, the thermal conversion to distillation capacity ratio was nearly doubled, providing the industry with the necessary operational flexibility to address the demand within the prevailing regulatory constraints in a profitable manner.

A geographical breakdown of the U.S. distillation capabilities clearly indicates coastal regions as areas with significant processing capacity. Because of their direct access to deep-water ports, they are more dependent on foreign crude imports to make up the refinery charge volume requirements.

During 1990, the refining industry responded to mounting environmental concerns, and earmarked significant investments to meet reduced emission motor gasoline specifications before the end of 1992. Capacities of primary downstream refining processes, which yield gasoline and diesel, logged gains, while processes that treat feeds for the secondary units increased because of feed requirements for acceptable quality conversion and light fuels.

The industry has begun accommodating itself to meet the increasingly stringent air quality regulations which require higher oxygen content gasolines in winter and less volatile gasolines in summer.

The U.S. refineries have made up more than half of their crude needs from domestic production. Declining domestic production will reverse this trend, most likely, early in the second half of this decade.

Forecasted Crude Supplies

A forecasted U.S. crude supply and demand balance shows moderate increases in crude requirements for refinery runs during the period under study (**Table 1**). Supplies of crudes, from both domestic and import sources, do not account for small amounts of associated domestic condensate included in the refinery intake slate.

A qualitative breakdown of the forecasted crude supplies to meet the needs for the U.S. refining industry (assuming no incremental domestic heavy oil production) exhibits an average 2% per year decline in domestic crude production, mainly in terms of ANS. California heavy crudes show a modest production decline per year (**Table 2**).

Crude imports from Africa, Europe and Asia are expected to decline as current production rates in some countries become unsustainable towards the future. Additionally, demand growth for environmentally desirable refined products will also curtail the availability of crude for export to the United States.

Despite all efforts by producing countries to increase their crude production capabilities, the Middle East area will be the incremental supplier of import crude to the U.S. refineries during the next decades.

Forecasted average crude intake gravities for the overall refinery system will be around 32 degrees API, and crude intake sulphur quality will deteriorate as higher sulphur Middle Eastern crudes replace declining domestic production.

U.S. CRUDE OIL SUPPLY AND DEMAND
(MB/D)

	DEMAND						SUPPLY			
	REFINERY RUNS	DIRECT TO FUEL	TO *SPR	EXPORTS	LOSS & UNACCNTD	TOTAL	TOTAL	DOMESTIC PROD'N	FROM INVEN	IMPORTS
1990	13409	24	0	113	(315)	13231	13231	7356	8	5867
1991	13350	19	0	121	(255)	13235	13234	7339	6	5889
1992	13322	15	0	90	(253)	13174	13174	7230	(11)	5955
1993	13262	10	0	85	(250)	13107	13107	7050	(30)	6087
1994	13391	5	0	80	(250)	13226	13226	6930	(2)	6298
1995	13416	0	0	80	(250)	13246	13246	6757	(10)	6499
1996	13550	0	0	80	(250)	13380	13380	6588	(10)	6802
1997	13684	0	0	80	(250)	13514	13514	6423	(9)	7100
1998	13802	0	0	80	(250)	13632	13632	6263	8	7361
1999	13692	0	0	80	(250)	13522	13522	6106	(2)	7418
2000	13721	0	0	80	(250)	13551	13551	5953	(5)	7603
2005	14087	0	0	80	(250)	13917	13917	5114	(11)	8814
2010	14462	0	0	80	(250)	14292	14292	4509	(10)	9793

* DOMESTIC CRUDE TO SPR

Table 1

U.S. CRUDE SUPPLIES
(No New Heavy Oil)

(MB/D)				1990	1995	2000	2005	2010
DOMESTIC								
PADD	**Region**	**API**	**%S**					
I	East Light	51.6	0.26	30	20	10	–	–
II/IV	Ok/Wyo	36.7	0.87	1,240	1,170	1,120	1,070	1,020
III	Tx/Lou	36.7	0.60	3,340	3,129	2,830	2,486	2,216
V	Alaska	27.8	1.12	1,773	1,490	1,070	660	400
	Continent	18.3	1.33	973	948	923	898	873
	Total U.S.			**7,356**	**6,757**	**5,953**	**5,114**	**4,589**
			API	**32.3**	**32.3**	**32.4**	**32.5**	**32.5**
			%S	**0.87**	**0.87**	**0.86**	**0.86**	**0.85**
IMPORTS								
	Region	**API**	**%S**					
	N. America	29.8	1.29	643	640	640	640	640
	S. America	24.8	2.20	1,624	1,805	2,055	2,255	2,425
	Mid East	32.9	1.80	1,863	2,444	3,558	4,609	5,418
	Africa	35.4	0.17	1,205	1,100	900	900	900
	Europe	37.6	0.40	251	230	220	200	200
	Asia	39.5	0.10	281	280	230	210	210
	Total Imports			**5,867**	**6,499**	**7,603**	**8,814**	**9,793**
			API	**31.4**	**31.2**	**31.0**	**31.1**	**31.2**
			%S	**1.38**	**1.46**	**1.58**	**1.63**	**1.65**
	TOTAL CRUDE			**13,223**	**13,256**	**13,556**	**13,928**	**14,302**
			API	**31.9**	**31.8**	**31.7**	**31.6**	**31.6**
			%S	**1.10**	**1.16**	**1.26**	**1.34**	**1.40**

Table 2

LOW INCREMENTAL HEAVY OIL PROJECTIONS

Proposed Refining Regions

For the purpose of this study, which is to identify the required additional refinery conversion capacity should incremental domestic heavy crude oil become available during the next twenty years, the Department of Energy (DOE) proposed ten regions to be evaluated. The refining industry profile used as Base Case 1990, and all projections throughout the study, have been developed according to these regions (**Figure 1**).

A detailed description of the different counties and geographical boundaries depicting the designated areas is available in the second volume of this report.

Volume Estimates

Projections of heavy oil production rates through the year 2010 were provided by NIPER. Estimates are conservative DOE targets that we have labeled our "LOW CASE," since we understand they are technically achievable with no major difficulties (**Table 3**).

Some assumptions on the estimated incremental regional production rates are:

1. The EPA does not regulate oil field produced water as hazardous waste. The refining industry continues to be environmentally conscious and meets current EPA regulations.

2. There are no government restriction or fees on importing crude oil. **The U.S. refining industry operates in a free world market economy.**

3. There is no government incentive program to stimulate heavy oil or EOR production.

4. The application of geothermal produced hot water for recovery of heavy oil on the Gulf Coast is successful at a pilot plant scale and grows toward commercial scale.-

5. **Environmental and economic restrictions continue to prevent the construction of new grass root heavy oil refineries.**

6. The trends in production of heavy oil in Los Angeles and Coastal Range Basins continue to follow the decline established over the past few years.

7. Continued environmental pressure keeps the Los Angeles refineries from expanding, but still allows them to operate within the Los Angeles Basin at the current processing levels.

8. Nationalized state oil companies, or major international companies, do not make a major push to take their foreign crude to dedicated refineries so they can corner the market in a given area.

These heavy crude oil projections were qualitatively incorporated for LP modeling purposes in the U.S. crude supply forecast, which is consistent with the occurrence of events described in **Appendix A, Worldwide Petroleum Balance, Section 1** in the second volume of the study.

U.S. HEAVY OIL REFINING CAPACITY PROPOSED REGIONAL ANALYSIS

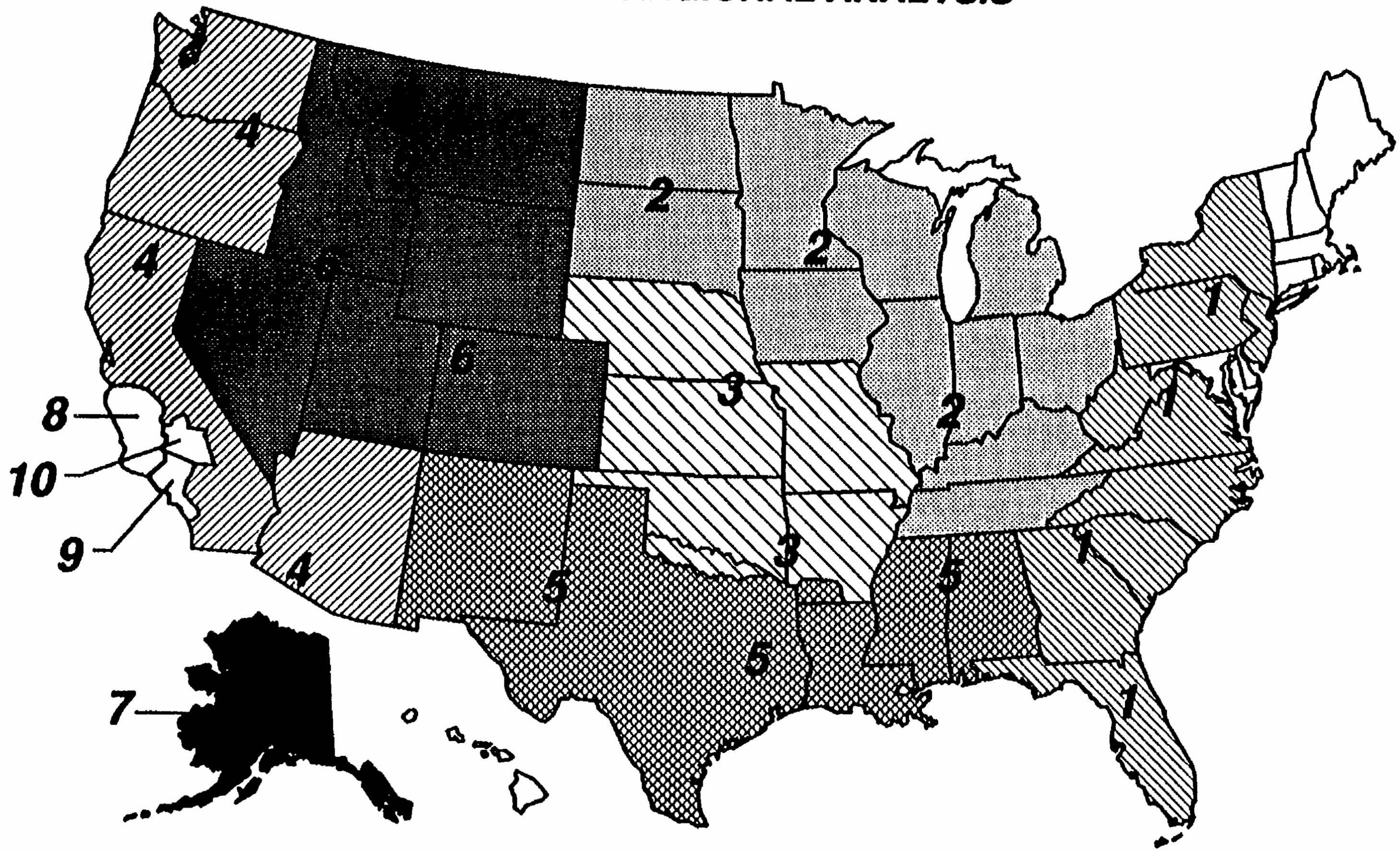

Figure 1

LOW HEAVY OIL PRODUCTION RATES THROUGH 2010

Proposed Region	General Location	DOE Estimates of Incremental Domestic Heavy Oil Production MB/D As of 1990	MB/D As of 1995	MB/D As of 2000	MB/D As of 2005	MB/D As of 2010
1	East Coast	0	0	0	0	0
	Incremental Production Rate	--	0	0	0	0
2	Upper Midwest	0.25	0.25	0.25	0.25	0.25
	Incremental Production Rate	--	0	0	0	0
3	Midwest (OK, KS, MS)	4.18	5.18	6.18	7.18	9.18
	Incremental Production Rate	--	1.00	1.00	1.00	2.00
4	West Coast (except Regions 8, 9, 10)	0.25	0.25	0.25	0.25	0.25
	Incremental Production Rate	--	0	0	0	0
5	Gulf States	63.96	74.96	108.96	159.96	260.96
	Incremental Production Rate	--	11.00	34.00	51.00	101.00
6	Rocky Mt. Region	20.25	21.25	25.25	28.25	28.25
	Incremental Production Rate	--	1.00	4.00	3.00	0
7	Alaska	0	0	0	1.00	5.00
	Incremental Production Rate	--	0	0	1.00	4.00
8	California Coastal Region	63.80	93.80	113.80	113.80	93.80
	Incremental Production Rate	--	30.00	20.00	0	-20.00
9	Los Angeles Basin	89.90	84.90	79.90	74.90	69.90
	Incremental Production Rate	--	-5.00	-5.00	-5.00	-5.00
10	San Joaquin Valley	500.60	525.60	550.60	563.60	575.60
	Incremental Production Rate	--	25.00	25.00	13.00	12.00
	Total Production Rate	743.19	806.19	885.19	949.19	1,043.19
	Total Incremental Production Rate	0	63.00	142.00	206.00	300.00

Table 3

CRUDE SUPPLIES FOR LP MODELS

In all refinery LP modeling efforts, there is a tradeoff between model complexity and accuracy of results. With this in mind, Regions 2 and 3 in the Midwest were grouped into one LP model, as well as Regions 8 and 9 in the California area. Aggregating refinery configurations in these areas reduces the modeling effort while the accuracy sought in the study is still being met. Region 7, which includes Alaska and Hawaii, was not modeled since the projected incremental heavy oil volumes for this area are relatively small, and will most likely will be blended in the ANS production with negligible qualitative impact.

Although Region 1, United States Atlantic East Coast (USAEC), has no incremental domestic heavy oil production planned, the region depends heavily on imports to meet its crude needs. Traditionally, South American medium and heavy crudes have made there way to this important refining region; therefore, all new heavy crude production from this foreign geographical area will most likely continue to take part in this market in the future. A detailed LP model was developed for Region 1 to assess the impact of these imports on refinery conversion capacities.

Also, in the same tenor "of sound modeling practices without jeopardizing accuracy," the number of crudes being represented in the LP models is another important consideration. A total of 18 crudes are being included in the models, of which 11 are domestic production. The imports are represented by an area's commercially known average crude quality, verified with historical data.

Because of the importance of the heavy crude that enters the United States blended with light crude from South America (as medium crude), two representative crude qualities are being considered for this geographical area; a heavy with 16.5 degrees API and a medium with 24.8 degrees API.

Base Case 1990

The U.S. crude supply data for the year 1990 has been chosen for LP model calibration purposes. Actual refinery runs and intake crude qualities show a 13,409 MB/D throughput level with 31.9 degrees API gravity and 1.1 percent sulphur, respectively. When the total crude barrels of imports (5,867 MB/D) plus domestic production (7,356 MB/D) is added to conform with the actual crude runs, a small deficit (186 MB/D) appears. This imbalance is being made up in the models with a light condensate-type material (**Table 4**).

The **ten region** distribution of the total crude supplies to the U.S. refineries during 1990 is evaluated using factual refinery crude slate data and industry knowledge of the gravities and sulphur qualities processed in the proposed areas. Since some of the boundaries differ significantly from the way data is grouped and published in the literature (by Petroleum Administration for Defense Districts (PADD)), the estimation of regional gravities required some judgement from Bonner & Moore consultants.

The regional gravity qualitative estimation and sulphur levels becomes crucial when forecasting the future refinery crude slates once incremental heavy crudes are incorporated. We will clarify this shortly.

CRUDE REPRESENTATION FOR REGIONAL LP MODELS

BASE CASE 1990

REGION	MB/D	VOL FRAC	API	%S	PROPOSED DOE REGION 1	2	3	4	5	6	7	8	9	10	TOTAL
East Light	30	0.002	51.6	0.26	13	2	0	0	15	0	0	0	0	0	30
Cushing Sweet	1155	0.086	39.4	0.42	0	465	141	0	297	253	0	0	0	0	1155
Mid West Sour	247	0.018	25.1	2.55	0	115	0	0	0	132	0	0	0	0	247
Mid West Hvy	4	0.000	18.8	1.98	0	0	4	0	0	0	0	0	0	0	4
Rocky Mt Hvy	20	0.001	19.8	3.30	0	0	0	0	0	20	0	0	0	0	20
West Texas Int.	1169	0.087	40.5	0.35	0	298	219	0	652	0	0	0	0	0	1169
Lousiana Sweet	2107	0.157	35.8	0.36	0	531	183	0	1393	0	0	0	0	0	2107
Gulf C Heavy	64	0.005	19.5	0.63	0	15	0	0	49	0	0	0	0	0	64
Alaska No Slope	1773	0.132	27.7	1.12	0	17	101	733	339	0	217	0	366	0	1773
California Med	319	0.024	28.7	0.68	0	0	0	41	0	0	0	0	203	75	319
California Hvy	654	0.049	13.1	1.21	0	0	0	327	0	0	0	8	286	33	654
Canada Blend	643	0.048	29.8	1.29	60	511	0	10	7	55	0	0	0	0	643
So America Med	1413	0.105	24.8	1.85	345	0	0	25	1042	0	0	0	1	0	1413
So America Hvy	211	0.016	16.5	2.40	100	0	0	1	110	0	0	0	0	0	211
Middle East	1863	0.139	32.9	1.80	266	199	16	24	1358	0	0	0	0	0	1863
Africa	1205	0.090	35.4	0.17	401	143	0	0	660	0	0	0	1	0	1205
Europe	251	0.019	37.6	0.40	68	27	18	0	138	0	0	0	0	0	251
Asia	281	0.021	39.5	0.10	32	7	0	33	0	0	20	0	189	0	281
	13409	1.000			1285	2330	682	1194	6060	460	237	8	1046	108	13409
			Target Supply		1285	2330	682	1194	6060	460	237	8	1046	108	13409

Table 4

The 1990 U.S. ten region crude **distribution** is the basis for all crude forecasts required by the LP models. All projections are based on the underlying assumption that supply logistics characterizing the Base Case 1990 resulted from a global optimum within the physical constraints imposed by the U.S. petroleum market and the prevailing economic conditions during that year. We are forecasting variations in the future economic conditions influencing the petroleum marketplace, but some of its physical constraints will remain unaltered.

As a reminder, the question being asked is not one of crude selection for the U.S. refining industry; rather, predicted crudes will be forced through the regional LP models in order to identify the necessary conversion capacities to economically process them.

Unbalanced 1995

As previously mentioned, the ten region crude distribution pattern followed in the Base Case 1990 is used in the study to forecast the crude supplies for the different refining regions.

An "unbalanced" case reflects the crude distribution as domestic ANS and light Midwest crude production decreases, domestic heavy oils increases, as estimated by NIPER, and the makeup of imports completes the planned refinery runs. Still, a small amount of condensate-type material is included (**Table 5**).

All regional shortfalls must be made up with excess crude from other areas in an effort to maintain, within limits, the crude intake quality as established in the Base Case 1990. Regional gravities are an essential element in establishing an acceptable crude quality range for a specific refining center since the distillation capacity and configuration responds to this critical feedstock property. Significant deviations from the refinery design gravity can cause problems in light ends handling and, therefore, must be minimized.

The crude balancing exercise is also necessary to meet the regional refined product demands with the existing refinery configuration; unfortunately, it also generates significant changes in the traditional crude supplies logistics to the U.S. refineries. Crudes that typically have made their way to a particular region will be forced to take advantage of idle distillation capacity in some areas (e.g., Region 9 because of less ANS) and freight incentives.

Balancing Criteria for 1995

An important assumption to consider when balancing the different refining regions is that both **incremental domestic and imported heavy crude oils must be processed near the production or traditional refining areas.** With the exception of Regions 8 and 10, no heavy oils are inter-regionally transferred to make up for any crude shortfall.

Significant loss of ANS crude dramatically impacts the use of available distillation capacity in Regions 4, 7, and 9.

To balance **Region 4**, we assume that excess South American medium crude previously destined for Region 1 will make its way through the Panama Canal, attaching additional cost to the refined products in Region 4. Replacement barrels for lost ANS in terms of South American medium will bring a small detriment in quality (marginal lower gravity, more sulphur). In an attempt to make up the quality loss, Region 4 refiners will fiercely try to secure Asian light sweet crudes, over and above the quantities already being processed there. We anticipate that Asian light sweet crude currently going to Region 1 will end up in Region 4, taking advantage of the freight savings.

CRUDE REPRESENTATION FOR REGIONAL LP MODELS

UNBALANCED 1995

REGION	MB/D	VOL FRAC	API	%S	PROPOSED DOE REGION 1	2	3	4	5	6	7	8	9	10	TOTAL
East Light	20	0.001	51.6	0.26	9	1	0	0	10	0	0	0	0	0	20
Cushing Sweet	989	0.074	39.4	0.42	0	398	120	0	254	217	0	0	0	0	989
Mid West Sour	233	0.017	25.1	2.55	0	109	0	0	0	125	0	0	0	0	233
Mid West Hvy	5	0.000	18.8	1.98	0	0	5	0	0	0	0	0	0	0	5
Rocky Mt Hvy	21	0.002	19.8	3.30	0	0	0	0	0	21	0	0	0	0	21
West Texas Int.	1095	0.082	40.5	0.35	0	279	205	0	611	0	0	0	0	0	1095
Lousiana Sweet	1974	0.147	35.8	0.36	0	497	172	0	1305	0	0	0	0	0	1974
Gulf C Heavy	75	0.006	19.5	0.63	0	18	0	0	57	0	0	0	0	0	75
Alaska No Slope	1490	0.111	27.7	1.12	0	14	85	616	285	0	182	0	308	0	1490
California Med	311	0.023	28.7	0.68	0	0	0	40	0	0	0	0	198	73	311
California Hvy	704	0.052	13.1	1.21	0	0	0	352	0	0	0	9	309	35	704
Canada Blend	640	0.048	29.8	1.29	60	509	0	10	7	55	0	0	0	0	640
So America Med	1570	0.117	24.8	1.85	383	0	0	28	1158	0	0	0	1	0	1570
So America Hvy	235	0.017	16.5	2.40	111	0	0	1	122	0	0	0	0	0	235
Middle East	2444	0.182	32.9	1.80	349	261	21	32	1781	0	0	0	0	0	2444
Africa	1100	0.082	35.4	0.17	366	131	0	0	602	0	0	0	1	0	1100
Europe	230	0.017	37.6	0.40	62	25	16	0	126	0	0	0	0	0	230
Asia	280	0.021	39.5	0.10	32	7	0	33	0	0	20	0	188	0	280
	13416	1.000		SUPPLY	1372	2248	624	1111	6320	417	202	9	1004	108	13416
				TARGET	1285	2332	682	1195	6063	460	237	9	1047	108	13416
				EX/(DF)	87	(84)	(58)	(83)	257	(43)	(35)	(0)	(42)	0	0

Table 5

Small volumes of Middle Eastern crude will also be required in Region 4 to fill up the remaining idle capacity (bringing it up to an 89% operating rate). No striking volumes of this crude quality can be processed because of limitations in overhead light product handling.

Regions 8 and 10 are producers of heavy California crude, over and above the requirements of the regional refineries. No crude balancing is required since ANS is not being depleted in their traditional crude slate. Excess crude is being sent to Regions 4 and 9, their historical outlets.

Balancing **Region** 7, as a result of ANS loss, will occur in terms of Middle Eastern quality crude otherwise destined to Region 5, United States Gulf Coast (USGC). This regional crude shortfall is mainly at the Hawaiian refineries which can qualitatively accommodate these light sour crudes. (There will be a moderate quality upgrade versus their current crude slate.)

To balance **Regions 2, 3 and 6**, all remaining excess crude in Region 5, in terms of Middle Eastern light sour, will cause the pipeline systems to reverse their current flow patterns as crude is pumped towards the inland refineries. The overall regional quality deteriorates somewhat as the Midwest light sweet is replaced by marginally heavier crude (32 versus 36 degrees API) and significantly more sour. **In addition to the quality degradation, these regions will be more dependent upon the changes of the international petroleum market, both for volumes and prices, than in the past.**

"Balanced" 1995 crude supplies for the different LP regional models shows a detailed crude distribution (consistent with the previous assumptions) necessary to meet the regional refinery crude needs and satisfy the demands for refined products (**Table 6**).

Estimates for 2000, 2005 and 2010

Crude requirements for future years are forecasted using the same criteria as explained for the year 1995. The major difference lies in the magnitude of the anticipated volumetric imbalances.

The net loss in ANS production by the year 2010 could very well exceed more than one million barrels per day (our estimates project a 1,373 MB/D drop during the next twenty years). On the other hand, incremental domestic heavy oil production, as estimated by NIPER, is expected to reach 300 MB/D in the Low Case.

Evidently, there will be a serious dependency on crude imports to fill the idle refining capacity and meet the U.S. refined product demands. This is particularly true for Region 9 (other California) where the bulk of the ANS production is currently destined. Coastal Regions 1 and 5, which depend heavily on imports for their crude needs, will provide their excess supplies to makeup for crude shortages at inland refineries and Region 9 (**Tables 7, 8 and 9**)

CRUDE REPRESENTATION FOR REGIONAL LP MODELS

BALANCED 1995

REGION	MB/D	VOL FRAC	API	%S	PROPOSED DOE REGION 1	2	3	4	5	6	7	8	9	10	TOTAL
East Light	20	0.001	51.6	0.26	9	1	0	0	10	0	0	0	0	0	20
Cushing Sweet	989	0.074	39.4	0.42	0	398	120	0	254	217	0	0	0	0	989
Mid West Sour	233	0.017	25.1	2.55	0	109	0	0	0	125	0	0	0	0	233
Mid West Hvy	5	0.000	18.8	1.98	0	0	5	0	0	0	0	0	0	0	5
Rocky Mt Hvy	21	0.002	19.8	3.30	0	0	0	0	0	21	0	0	0	0	21
West Texas Int.	1095	0.082	40.5	0.35	0	279	205	0	611	0	0	0	0	0	1095
Lousiana Sweet	1974	0.147	35.8	0.36	0	497	172	0	1305	0	0	0	0	0	1974
Gulf C Heavy	75	0.006	19.5	0.63	0	18	0	0	57	0	0	0	0	0	75
Alaska No Slope	1490	0.111	27.7	1.12	0	14	85	616	285	0	182	0	308	0	1490
California Med	311	0.023	28.7	0.68	0	0	0	40	0	0	0	0	198	73	311
California Hvy	704	0.052	13.1	1.21	0	0	0	352	0	0	0	9	309	35	704
Canada Blend	640	0.048	29.8	1.29	60	509	0	10	7	55	0	0	0	0	640
So America Med	1570	0.117	24.8	1.85	345	0	0	66	1116	0	0	0	43	0	1570
So America Hvy	235	0.017	16.5	2.40	111	0	0	1	122	0	0	0	0	0	235
Middle East	2444	0.182	32.9	1.80	336	345	79	45	1561	43	35	0	0	0	2444
Africa	1100	0.082	35.4	0.17	366	131	0	0	602	0	0	0	1	0	1100
Europe	230	0.017	37.6	0.40	62	25	16	0	126	0	0	0	0	0	230
Asia	280	0.021	39.5	0.10	0	7	0	65	0	0	20	0	188	0	280
	13416	1.000		SUPPLY	1289	2332	682	1195	6057	460	237	9	1046	108	13416
				TARGET	1286	2332	682	1195	6061	460	237	9	1046	108	13416

Table 6

CRUDE REPRESENTATION FOR REGIONAL LP MODELS

BALANCED 2000

REGION	MB/D	VOL FRAC	API	%S	PROPOSED DOE REGION 1	2	3	4	5	6	7	8	9	10	TOTAL
East Light	10	0.001	51.6	0.26	4	1	0	0	5	0	0	0	0	0	10
Cushing Sweet	853	0.062	39.4	0.42	0	343	104	0	219	187	0	0	0	0	853
Mid West Sour	223	0.016	25.1	2.55	0	104	0	0	0	119	0	0	0	0	223
Mid West Hvy	6	0.000	18.8	1.98	0	0	6	0	0	0	0	0	0	0	6
Rocky Mt Hvy	25	0.002	19.8	3.30	0	0	0	0	0	25	0	0	0	0	25
West Texas Int.	990	0.072	40.5	0.35	0	252	186	0	552	0	0	0	0	0	990
Lousiana Sweet	1785	0.130	35.8	0.36	0	450	155	0	1180	0	0	0	0	0	1785
Gulf C Heavy	109	0.008	19.5	0.63	0	26	0	0	83	0	0	0	0	0	109
Alaska No Slope	1070	0.078	27.7	1.12	0	10	61	442	205	0	131	0	221	0	1070
California Med	303	0.022	28.7	0.68	0	0	0	39	0	0	0	0	193	71	303
California Hvy	744	0.054	13.1	1.21	0	0	0	372	0	0	0	9	325	37	744
Canada Blend	640	0.047	29.8	1.29	60	509	0	10	7	55	0	0	0	0	640
So America Med	1788	0.130	24.8	1.85	257	0	0	211	1144	0	0	0	176	0	1788
So America Hvy	267	0.019	16.5	2.40	127	0	0	1	139	0	0	0	0	0	267
Middle East	3558	0.259	32.9	1.80	508	554	171	93	2052	86	95	0	0	0	3558
Africa	900	0.066	36.4	0.17	300	107	0	0	493	0	0	0	1	0	900
Europe	220	0.016	37.6	0.40	60	24	16	0	121	0	0	0	0	0	220
Asia	230	0.017	39.5	0.10	0	6	0	53	0	0	16	0	155	0	230
	13721	1.000		SUPPLY	1315	2385	698	1221	6201	471	242	9	1070	108	13721
				TARGET	1314	2385	698	1222	6201	471	242	9	1070	110	13721

Table 7

CRUDE REPRESENTATION FOR REGIONAL LP MODELS

BALANCED 2005

REGION	MB/D	VOL FRAC	API	%S	PROPOSED DOE REGION 1	2	3	4	5	6	7	8	9	10	TOTAL
East Light	0	0.000	51.6	0.26	0	0	0	0	0	0	0	0	0	0	0
Cushing Sweet	720	0.051	39.4	0.42	0	290	88	0	185	158	0	0	0	0	720
Mid West Sour	213	0.015	25.1	2.55	0	99	0	0	0	114	0	0	0	0	213
Mid West Hvy	7	0.000	18.6	1.96	0	0	7	0	0	0	0	0	0	0	7
Rocky Mt Hvy	28	0.002	19.8	3.30	0	0	0	0	0	28	0	0	0	0	28
West Texas Int.	870	0.062	40.5	0.35	0	222	163	0	485	0	0	0	0	0	870
Lousiana Sweet	1568	0.111	35.8	0.36	0	395	136	0	1037	0	0	0	0	0	1568
Gulf C Heavy	160	0.011	19.5	0.63	0	38	0	0	122	0	0	0	0	0	160
Alaska No Slope	660	0.047	27.7	1.12	0	6	38	273	126	0	81	0	136	0	660
California Med	294	0.021	28.7	0.68	0	0	0	38	0	0	0	0	180	76	294
California Hvy	752	0.053	13.1	1.21	0	0	0	376	0	0	0	9	329	38	752
Canada Blend	640	0.045	29.8	1.29	60	509	0	10	7	55	0	0	0	0	640
So America Med	1962	0.139	24.8	1.85	257	0	0	257	1136	0	0	0	312	0	1962
So America Hvy	293	0.021	16.5	2.40	139	0	0	1	153	0	0	0	0	0	293
Middle East	4609	0.327	32.9	1.80	540	757	271	250	2512	127	153	0	0	0	4610
Africa	900	0.064	35.4	0.17	300	107	0	0	493	0	0	0	1	0	900
Europe	200	0.014	37.6	0.40	54	22	14	0	110	0	0	0	0	0	200
Asia	210	0.015	39.5	0.10	0	5	0	49	0	0	15	0	141	0	210
	14087	1.000		SUPPLY	1349	2449	717	1254	6366	481	249	9	1099	114	14087
				TARGET	1350	2448	716	1254	6366	483	249	9	1099	113	14087

Table 8

CRUDE REPRESENTATION FOR REGIONAL LP MODELS

BALANCED 2010

					PROPOSED DOE REGION										
REGION	MB/D	VOL FRAC	API	%S	1	2	3	4	5	6	7	8	9	10	TOTAL
East Light	0	0.000	51.6	0.26	0	0	0	0	0	0	0	0	0	0	0
Cushing Sweet	564	0.039	39.4	0.42	0	227	69	0	145	124	0	0	0	0	564
Mid West Sour	203	0.014	25.1	2.55	0	95	0	0	0	109	0	0	0	0	203
Mid West Hvy	9	0.001	18.8	1.98	0	0	9	0	0	0	0	0	0	0	9
Rocky Mt Hvy	28	0.002	19.8	3.30	0	0	0	0	0	28	0	0	0	0	28
West Texas Int.	776	0.054	40.5	0.35	0	198	145	0	433	0	0	0	0	0	776
Lousiana Sweet	1398	0.097	35.8	0.36	0	352	121	0	924	0	0	0	0	0	1398
Gulf C Heavy	261	0.018	19.5	0.63	0	61	0	0	200	0	0	0	0	0	261
Alaska No Slope	400	0.028	27.7	1.12	0	4	23	165	76	0	49	0	83	0	400
California Med	286	0.020	28.7	0.68	0	0	0	37	0	0	0	0	182	67	286
California Hvy	744	0.051	13.1	1.21	0	0	0	372	0	0	0	9	314	49	744
Canada Blend	640	0.044	29.8	1.29	60	509	0	10	7	55	0	0	0	0	640
So America Med	2110	0.146	24.8	1.85	257	0	0	295	1151	0	0	0	407	0	2110
So America Hvy	315	0.022	16.5	2.40	149	0	0	1	164	0	0	0	0	0	315
Middle East	5418	0.375	32.9	1.80	566	935	354	358	2832	180	192	0	0	0	5417
Africa	900	0.062	35.4	0.17	300	107	0	0	493	0	0	0	1	0	900
Europe	200	0.014	37.6	0.40	54	22	14	0	110	0	0	0	0	0	200
Asia	210	0.015	39.5	0.10	0	5	0	49	0	0	15	0	141	0	210
	14462	1.000		SUPPLY	1386	2514	736	1288	6535	495	256	9	1128	116	14462
				TARGET	1385	2513	736	1288	6536	496	256	9	1128	116	14462

Table 9

ESTIMATED CONVERSION CAPACITY REQUIREMENTS

General Comments

As mentioned before, additional (new) bottoms conversion capacities reported in this study refer to delayed coking. This well established process thermally "cracks" hydrocarbons otherwise destined for asphalt or residual fuel oil sales into refinery stocks suitable for processing into higher value gasoline and distillate fuels. Other types of bottoms conversion technology exists in U.S. refineries and these processes and capacities are recognized.

Capacity additions shown throughout the report are in units of MB/D or "thousands of barrels per calender day." This unit of measure is consistent with that used for refinery crude oil intake slate and refined products demands in all regional LP models.

Reformulated motor fuels, necessary to meet the 1990 Amendments to the Clean Air Act (CAA), are acknowledged by the regional LP models as of 1995. The average motor gasoline pool for the United States is estimated to be 35% reformulated in 1995 and 2000; for 2005 and 2010, the overall average is increased to 50%. An attempt has been made to apportion these national averages among the proposed regions based on published non-attainment areas.

Automotive diesel fuel quality mandated under the provisions of the CAA is estimated to average 47% of the diesel produced beginning in 1995. Although the 47% U.S. average was maintained across the 1995 to 2010 period, a distinction is made among the different regions. The biggest factor to recognize is agricultural or other off-road use.

These apportionments are necessary to make the refining cost calculations more accurate between the regions. As the reader shall see, the refining costs associated with complying with CAA motor fuel quality are very large; much greater than costs associated with increasing the amount of heavy crude oil.

As part of this reformulated fuels environment, motor gasolines must contain oxygenates. There are various means available to the refiner-marketer to accomplish this. Each will have certain advantages and disadvantages, depending on the particular location. For the purposes of this study, we have restricted the oxygenates to MTBE and TAME, both of which can be produced from typical refinery feedstocks.

The individual regional models were allowed to purchase **or** produce MTBE to meet oxygenate requirements for reformulated gasoline specifications. However, any level purchased in 2000 was established as the **maximum** allowed for years 2005 and 2010. This modeling restriction was set to insure the model estimated the investment costs for producing oxygenates in the later years, and avoid all regions depending on the "open market" for oxygenated components.

Finally, as a reminder, this study was commissioned by NIPER for the DOE to estimate the magnitude of refining investment costs incurred by increasing the production of heavy crude oil in the United States. Hence, the study recognizes the economic impact of the anticipated changes in motor fuel quality between the years 1990 and 2010. However, the study was **not** intended to determine the cost of producing reformulated motor fuels, and the individual reader should not try to infer such.

Regional LP Models Results

REGION 1 -- This (USAEC) region produces small amounts of domestic crude, yet no heavy oil, to supply area refineries. Foreign crude imports amount to nearly 99% of the intake slate. Some of the imported crude has a gravity less than 20 degrees API and is purchased mainly for the purpose of producing seasonal asphalts. From the NIPER estimates, **no indigenous heavy crude oil production is projected for the future, and planned increases in other areas of the United States will have virtually no direct impact (Table 10).**

These refineries are in a privileged geographical position to acquire crude oils from all parts of the world, except Asia. This allows the regional refiner considerable flexibility to adjust crude quality to seasonal product demands, circumventing the need for capital expenditures on process conversion technology. The small change anticipated in calculated gravity of crudes over the twenty year study period is indicative of our belief that this crude selection process will endure.

Additionally, this refining area acquires refined fuel products from several different sources: product pipeline and marine deliveries from the U.S. Gulf Coast; and imports from the Caribbean, eastern Canada and Europe. The region's dependency on imports to meet bottom-of-the-barrel demands can be vividly confirmed with historical data: imported asphalt was 94% of the **total US asphalt imports** in 1990 and 36% of that was produced from all regional refineries; imported residual fuel amounted to 88% of the **total US residual imports**, an astonishing **3.25 times** more than the amounts from other regions.

To meet the requirements of the CAA, this region is anticipated to have a reformulated gasoline pool greater than the assumed national average of 35% until 2000, and 50% thereafter. This study assumed 40% for Region 1 until 2000 and 57% thereafter. For automotive diesel, the regional demand used was 50% of the diesel produced versus the expected U.S. average of 47%.

The regional LP model shows additional bottoms conversion capacity being economically unattractive until 2000. The 17 MB/D shown for 2010 is 25% of that reported in operation for 1990. **To say with conviction that this amount of conversion will be built, given the large imported amounts of offshore asphalt and residual fuel mentioned earlier, is somewhat uncertain.**

REGIONS 2 & 3 -- These two regions were combined for LP model analysis. This is a very reasonable and appropriate aggregation since Region 3 has surplus indigenous crude and is the transportation hub for crude oil pipelines that provide much of Region 2's supply. Region 3 currently produces about 4.2 MB/D of heavy crude and incremental production up to 9.2 MB/D is expected in 2010. Most of the current and future heavy crude will be diluted with lighter crudes for pipeline shipment into Region 2. The latter is only producing 0.25 MB/D of heavy crude oil in 1990 and no increase is anticipated through 2010.

The regions refineries currently produce relatively little residual fuel oil. This is due to 3 factors: asphalt is stored over the winter months in order to have adequate supply for the next paving season; a significant decline has occurred in the heavy manufacturing industries, reducing fuel oil demands; and there is also a significant amount of existing bottoms conversion capacity to help control bottom-of-the-barrel inventories over the (sometimes long) winter months.

SUMMARY OF LP MODEL RESULTS
LOW HEAVY OIL PRODUCTION

	Region 1 1990	1995	2000	2005	2010		Regions 2 & 3 1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD						**Refinery Crude Intake, MBCD**					
Domestic	13	9	4	0	0	Domestic	2,091	1,903	1,698	1,482	1,304
Imports	1,272	1,280	1,312	1,349	1,386	Imports	921	1,112	1,387	1,685	1,946
Total	1,285	1,289	1,316	1,349	1,386	Total	3,012	3,015	3,085	3,167	3,250
Calculated Gravity, API						**Calculated Gravity, API**					
Base Case	31.1	31.1	31.1	31.1	31.1	Base Case	34.5	34.5	34.5	34.5	34.5
New Heavy Oil	--	30.2	30.4	30.3	30.2	New Heavy Oil	--	35.0	34.6	34.2	33.8
Major Products, MBCD						**Major Products, MBCD**					
Gasoline	641	696	692	706	722	Gasoline	1,789	1,791	1,797	1,835	1,875
Light Distillate	91	111	118	128	138	Light Distillate	200	235	259	282	303
Middle Distillate	256	220	236	290	297	Middle Distillate	709	725	746	789	832
Fuel Oil	147	146	145	145	145	Fuel Oil	64	64	62	62	63
Capacity Added, MBCD						**Capacity Added, MBCD**					
Crude Distillation	--	4	31	65	101	Crude Distillation	--	27	97	179	262
Vacuum Distillation	--	17	27	48	67	Vacuum Distillation	--	44	97	155	216
Bottoms Conversion	--	0	0	11	17	Bottoms Conversion	--	0	31	60	87
Motor Fuel Quality	--	0	0	162	165	Motor Fuel Quality	--	0	0	225	287
Capital Investment, MM$	--	23	91	558	625	**Capital Investment, MM$**	--	57	250	892	1,075

Table 10

Region 2 and 3 were assumed to have a reformulated gasoline requirement of 25% and 20%, respectively, for 1995 and 2000, considerably below the U.S. average of 35%. This was due to the relatively few cities that are mandated (currently) or expected to "opt in". For the years 2005 and 2010, the respective levels were assumed to be 35% and 29% when compared to the expected U.S. average of 50%.

For highway diesel, the demand used was assumed to be 30% and 47% for Regions 2 & 3, respectively, versus the expected U.S. average of 47%. The low usage in Region 2 is related to its large demand of No. 2 diesel fuel for agriculture and other off-road use.

Required bottoms conversion capacity in these areas indicates the need for approximately 30 MB/D in the year 2000 and increments of roughly an additional 30 MB/D in 2005 and 2010, respectively (Table 10).

REGION 4 -- This geographic area of the western United States currently produces essentially no indigenous heavy crude, and will have no incremental production under NIPER scenarios being evaluated. The total amount of crude currently produced is also very small, about 12 MB/D in 1990, and most of this came from California from other defined regions (8, 9 and 10).

The region has two major refining centers. The Puget Sound area of Washington has a crude processing capacity of 462 MB/D, or 37% of the region's total, and most of it was built specifically to process Alaskan North Slope crude. Other crudes constitute a very small percentage. As the amount of this crude declines for the other U.S. refining centers, it will still be refined here because of its geographic location and efficiency of plant design. Incremental heavy crude oil produced elsewhere will not be processed at these refineries.

The other major refining center is San Francisco. The aggregated capacity here is 757 MB/D of crude processing, or 61% of the region's total. Refinery configuration, or complexity, is similar to that observed for Los Angeles (Region 9). It was designed to efficiently process the heavy crude oil from the San Joaquin Valley. Some of the incremental production expected from Regions 8 and 10 will be processed here.

The investment costs associated with processing the additional heavy crude at San Francisco will be negligible. Most of the costs shown in **Table 11** are a direct function of demand growth and reformulated motor fuel regulations, not from changes in crude quality.

The reformulated motor fuel quality specifications used in the regional LP study were the same as those assumed for the United States as a whole. In reality, we feel that this will not be the case because of the efforts of the California Air Resources Board to gain control over the San Francisco area. The accuracy associated with trying to aggregate quality would always be questionable. The percentage of reformulated gasoline sales was assumed to be 45% for 1995 and 2000, increasing to 64% for the years 2005 and 2010. U.S. averages for the time periods were 35% and 50%, respectively. Reformulated highway diesel was assumed to be 60%, versus the U.S. average of 47%, for all years.

REGION 5 -- This geographical region is the largest producer of crude oil in the United States (44% of the total domestic production), and also has the largest concentration of refining capacity (43% of primary distillation). Even so, imports made up almost 55% of the total crude oil processed in 1990 and are expected to grow to about 73% in 2010. This is because the producing areas of New Mexico and north and west Texas divert a significant amount of their crude production (595 MB/D in 1990) north into the pipeline system for supplying Region 2.

SUMMARY OF LP MODEL RESULTS
LOW HEAVY OIL PRODUCTION

	Region 4				
	1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD					
Domestic	1,101	1,008	853	687	574
Imports	93	187	368	567	713
Total	1,194	1,195	1,221	1,254	1,287
Calculated Gravity, API					
Base Case	24.3	24.3	24.3	24.3	24.3
New Heavy Oil	--	24.1	23.7	23.3	24.7
Major Products, MBCD					
Gasoline	594	594	581	594	608
Light Distillate	170	211	225	245	265
Middle Distillate	225	207	210	222	233
Fuel Oil	165	159	159	161	162
Capacity Added, MBCD					
Crude Distillation	--	1	27	60	93
Vacuum Distillation	--	0	28	51	65
Bottoms Conversion	--	0	0	0	0
Motor Fuel Quality	--	0	0	110	124
Capital Investment, MM$	--	3	91	482	538

	Region 5				
	1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD					
Domestic	2,745	2,522	2,244	1,955	1,778
Imports	3,315	3,534	3,956	4,411	4,757
Total	6,060	6,056	6,200	6,366	6,535
Calculated Gravity, API					
Base Case	33.1	33.1	33.1	33.1	33.1
New Heavy Oil	--	32.7	32.5	32.2	31.9
Major Products, MBCD					
Gasoline	3,123	3,286	3,245	3,316	3,392
Light Distillate	668	823	880	956	1,031
Middle Distillate	1,260	1,130	1,220	1,451	1,531
Fuel Oil	362	351	351	354	357
Capacity Added, MBCD					
Crude Distillation	--	143	287	453	622
Vacuum Distillation	--	386	350	599	570
Bottoms Conversion	--	0	0	84	100
Motor Fuel Quality	--	300	310	1,031	1,118
Capital Investment, MM$	--	848	890	1,724	1,967

Table 11

Heavy crude oil amounted to only 64 MBCD during 1990, or less than 2% of the region's total indigenous crude production. All is diluted with lighter crudes for pipeline delivery to Region 5 refineries or north to Region 2. Under the NIPER estimates used for this study, heavy oil production could increase to 261 MB/D by 2010. Although it would constitute a much greater percentage than 1990, **this increased domestic heavy oil is not expected to have a significant impact on refining operations in general, or bottoms conversion capacity, until about 2005.**

This conclusion is reasonable when one considers that this refining region contains many of the largest and most sophisticated refineries in the world. Significant capital investments in technology and metallurgy have been made in this area since October 1973 to ensure the region the capability of processing any type of crude oil into light fuel products and petrochemicals. **Bottoms conversion was an obvious key factor for these investments, and substantial operating flexibility currently exists for processing heavy oil.** With the inclusion of **announced** capacity changes prior to 1995, the region is well positioned to handle increased amounts of U.S. heavy oil with a minimum amount of refining costs until after 2000 (**Table 11**).

Although the region has few localities mandated for use of reformulated fuels, it does supply a large portion of motor fuels into eastern and midwestern localities that are, or expected to be, mandated by the CAA. Because of the physical limitations associated with product blending, storage, and transportation, we have required Region 5 to produce the U.S. average for reformulated motor fuels: for gasoline this is 35% in 1995 and 2000, increasing to 50% in 2005 and 2010. Automotive diesel remains at 47% for the entire period.

REGION 6 -- This region is composed of the six Rocky Mountain states. Although a large geographic area, it is relatively isolated or self-contained from a refining standpoint. On paper, in 1990, the region was closely balanced in crude production and refining capacity, 498 versus 486 MB/D, respectively. However, given its relatively close proximity to Canadian fields, about 90 MB/D of indigenous production was pipelined into Region 2. Heavy crude oil made up 20 MB/D of the production in 1990 and it is expected this could increase to 28 MB/D in 2010.

As seen in **Table 12**, the regional **LP model has selected to build bottoms conversion capacity in 1995.** This is a different situation than evidenced for the other regions. Notice that the demand for residual fuel oil is low, coming mostly in the winter months, and the asphalt is also very seasonal. This can create a difficult supply situation since there is no navigable water way to transport surplus product to a large consuming market; rail cars are expensive and difficult to schedule, especially in the winter. Therefore, to keep heavy product inventories in balance, refiners located adjacent to crude pipelines, sometimes inject "reduced" crude for reprocessing in Region 2. These pipeline exchanges (returns) are not finished products and the regional LP model has found economic incentives to eliminate most of this unfinished oil. This is done by building the bottoms conversion capacity in 1995 and turning it into light fuel products. Between 1990 and 1995 only 1.0 MB/D of **incremental** heavy oil is made available to regional refineries; therefore, the balance of the 19 MB/D of conversion capacity to be built by the model in 1995 is mainly to upgrade the "extra" fuel oil from the heavy crude production.

Even with the unrestricted option of building facilities for 1995 and beyond, the regional LP model still had to "dump" over 3 MBCD of an unfinished oil called cat cracker decanted oil. This is a highly refractory "cracked" stock and cannot be returned to crude oil pipelines. It is usually only suitable for blending into residual fuel oil. It is not at all unusual for some refiners in this region to store excess material in railroad tank cars for shipment outside the region.

SUMMARY OF LP MODEL RESULTS
LOW HEAVY OIL PRODUCTION

	Region 6						Region 7				
	1990	1995	2000	2005	2010		1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD						**Refinery Crude Intake, MBCD**					
Domestic	405	363	331	300	261	Domestic	217	182	131	81	49
Imports	55	98	140	182	235	Imports	20	55	111	168	207
Total	460	461	471	482	496	Total	237	237	242	249	256
Calculated Gravity, API						**Calculated Gravity, API**					
Base Case	35.5	35.5	35.5	35.5	35.5	Base Case	29.5	29.5	29.5	29.5	29.5
New Heavy Oil	--	32.8	32.5	32.1	31.7	New Heavy Oil	–	29.5	30.5	31.6	32.3
Major Products, MBCD						**Major Products, MBCD**					
Gasoline	248	247	246	246	244	Gasoline					
Light Distillate	27	34	36	39	42	Light Distillate					
Middle Distillate	122	112	121	123	139	Middle Distillate					
Fuel Oil	8	8	8	8	8	Fuel Oil					
Capacity Added, MBCD						**Capacity Added, MBCD**					
Crude Distillation	--	36	46	57	71	Crude Distillation					
Vacuum Distillation	--	44	52	60	70	Vacuum Distillation					
Bottoms Conversion	--	19	21	25	26	Bottoms Conversion					
Motor Fuel Quality	--	45	46	56	45	Motor Fuel Quality					
Capital Investment, MM$	--	301	332	417	425	**Capital Investment, MM$**					

Table 12

This region will also be relatively unaffected by CAA mandates for reformulated motor fuels. We have assumed a motor gasoline level of only 10% for 1995 through 2000 and 14% for 2005 through 2010. These are considerably below the expected national averages of 35% and 50%. For diesel fuel, highway diesel was assumed to require 30% of the total versus the expected national average of 47%.

Because of the region's lower average temperatures, the yearly average RVP was increased to 9.0 in the regional LP model from the 8.0 used for most of the reformulated motor gasoline in 2000.

REGION 9 -- This region, known as the Los Angeles Basin, has a major impact on this study in several ways: 1) it is the largest, single **urban** refining center in the country, 2) it currently produces 12% of the heavy crude oil in the United States, and 3) it has highest levels of air quality contamination. The latter results mainly from the geographical location and automotive emissions. This combination has spawned a slate of local air quality regulations that, as we shall see, will require huge capital expenditures for the refiner.

The total amount of indigenous crude oil produced in the region amounted to almost 150 MB/D in 1990, with about 90 MB/D, or 60%, being heavy oil. The fields are mature and in decline; heavy oil production is expected to **decline** at a rate of 5 MB/D per year and reach a level of 70 MB/D in 2010.

Because of the quality of indigenous crudes and its geographical proximity to the San Joaquin Valley (Region 8), refineries in the Los Angeles Basin were originally designed to process heavy crude. A considerable amount of bottoms conversion capacity currently exists and should be sufficient to accommodate the incremental heavy oil being moved to the area during the study's time period. **The regional LP results confirm this by electing not to build any additional capacity (Table 13).**

The large amount of crude and vacuum distillation capacity shown to be built in 1995 (199 and 160 MB/D, respectively) is **not** entirely a result of related product demand growth, but reflects the need to reinstate the capacity, which has recently been unavailable due to decisions by some refiners to suspend operations rather than spend large amounts of capital to attain compliance with reformulated motor fuels qualities. Again, it bears mentioning that motor fuel qualities expected for the Los Angeles Basin beginning January 1, 1996 will be much more restrictive (i.e., costly) than any other urban area in the world. **The individual refiners who currently make up this shutdown list in Region 9 are as follows:**

Company	Location	Capacity Loss MB/D	Status
Edgington Oil	Long Beach	44	Closed
Fletcher Oil	Carson	30	May Close
Golden West	Santa Fe Springs	46	Closed
Unocal/Shell	Los Angeles	111	Partially Closed

Region 9 was assumed to be producing reformulated motor gasoline at a 90% apportionment factor for 1995 and 2000 and increasing to 100% for the years 2005 and 2010. The national average is estimated to be 35% and 50%, respectively. Reformulated highway motor diesel apportionment was assumed to be 80% for all years, also substantially above the national average of 47%. The quality of motor fuels required for 1995 were the same as the rest of the United States, with the exception of a lower RVP for gasoline (8 vs.9).

SUMMARY OF LP MODEL RESULTS
LOW HEAVY OIL PRODUCTION

	Region 9						Regions 8 & 10				
	1990	1995	2000	2005	2010		1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD						**Refinery Crude Intake, MBCD**					
Domestic	855	815	739	645	579	Domestic	116	117	117	123	125
Imports	191	231	332	454	549	Imports	0	0	0	0	0
Total	1,046	1,046	1,071	1,099	1,128	Total	116	117	117	123	125
Calculated Gravity, API						**Calculated Gravity, API**					
Base Case	26.3	26.3	26.3	26.3	26.3	Base Case	26.4	26.4	26.4	26.4	26.4
New Heavy Oil	--	25.6	24.7	24.1	24.2	New Heavy Oil	--	23.9	23.7	23.4	22.4
Major Products, MBCD						**Major Products, MBCD**					
Gasoline	549	605	629	693	801	Gasoline	28	34	35	50	52
Light Distillate	149	185	197	215	232	Light Distillate	16	20	21	23	25
Middle Distillate	175	127	183	194	143	Middle Distillate	26	26	26	28	30
Fuel Oil	145	140	139	140	142	Fuel Oil	16	16	16	17	17
Capacity Added, MBCD						**Capacity Added, MBCD**					
Crude Distillation	--	199	224	252	281	Crude Distillation	--	1	1	7	9
Vacuum Distillation	--	160	203	239	261	Vacuum Distillation	--	0	3	16	22
Bottoms Conversion	--	0	0	0	0	Bottoms Conversion	--	0	0	0	0
Motor Fuel Quality	--	360	377	663	687	Motor Fuel Quality	--	28	26	46	52
Capital Investment, MM$	--	976	1,511	2,026	2,012	**Capital Investment, MM$**	--	177	227	371	408

Table 13

REGIONS 8 & 10 -- These two regions were combined for the regional LP analysis. This is very reasonable given their geographical proximity; individually limited areas, nominal refining capacity and large production of heavy crude oil. For example, Region 8 produces almost 64 MB/D of heavy oil, but there is only one small refinery (8 MB/D); similarly, Region 10 has ten refineries, totaling only 109 MB/D of primary capacity, but it produces over 500 MB/D of heavy oil (approximately 670 MB/D total crude).

From the refining technology perspective, these refineries were not designed to process heavy oil as were the refineries in the Los Angeles or San Francisco area. The heavy crude oil has been mixed with lighter crude and sent by pipeline to these two populated refinery centers. Coking technology was used to convert the heavy oil to motor fuels. These coastal locations also had deep water ports; a significant advantage for refiners with large amounts of solid coke byproduct to dispose of.

Among the eleven active refiners in Region 8 & 10, there are currently **no** catalytic crackers and only one coker. They were designed to supply the local San Joaquin Valley urban and agricultural interests with light fuel products and asphalt, and could select the appropriate crude quality to minimize hardware technology costs. Some amounts of unfinished stocks were also produced. These would be redistributed locally or transported to Los Angeles. The LP case for 1990 simulated this by producing about 9 MB/D of unfinished stocks. Given the option in later years of building capacity, the unfinished stock disappeared.

The NIPER data used as the basis for projected heavy oil crude production indicates that Region 8 heavy oil availabilities could increase by 30 MB/D in 1995 and an additional 20 MB/D in 2000. Production at this level (approximately 114 MB/D) could only be sustained until 2005 when production declines would begin. By 2010 heavy oil production would be decreased by 20 MB/D, or back to the level of 1995. The bulk of this production will be in offshore fields.

Region 10 also shows considerable capability to produce additional quantities of heavy crude between 1990 and 2010, increasing to over 575 MB/D. All of this crude would be produced from existing fields.

The LP chose to build no bottoms conversion capacity over the four time periods, probably for much the same reasons as mentioned earlier; product demands from area refineries are in balance with the replacement crude quality. **The major capital expenditure the LP did select was for process technology to improve the environmental quality of products**; e.g., cat cracking, hydrocracking (**Table 13**).

Detailed New Facilities Investments

Our discussion in the previous section centered on the regional LP model results identifying the amount of bottoms conversion capacity required to process NIPER's projected incremental domestic heavy oil production. These incremental barrels have been qualitatively commingled with our crude imports volume estimates to jointly replace the projected ANS production decline (and other Midwest light sweet crudes) and still meet the country's refined product demands during the next twenty years.

The conversion capacity figures generated by the regional LP models reflect the combined effects of all crude supply sources (new heavy oil, imports, and declining domestic production) and the CAA environmental restrictions on refined product demands. The latter also incorporates growth factors consistent with our assumptions on economic activity and the associated product price structure driving the models.

As in any economic analysis and, in particular, those involving mathematical abstractions of physical processes (like LP models), all supply demand effects tend to be evaluated collectively. To assume that there will be incentives for capital investments without any economic activity (in an unregulated industry) seems unrealistic. Consequently, demand growth is a **fundamental** assumption in this study and has been set at extremely conservative levels, as explained in detail in the second volume of the report.

The investment requirements necessary to comply with the Amendments to the Clean Air Act (CAA) are complicated to isolate from all other factors contemplated in a study of this nature. However, as a request from NIPER, we have tried to separate them by setting refined product demands at 1990 specifications and re-run all regional models. An analysis of these results are presented in the next section.

The regional LP models were configured using 1990 capacity data as a base and include all **announced** capacity additions (both primary distillation and secondary units) being planned, or under construction, for the next years. This essentially means that new capacity additions from LP model results are over and above what the U.S. refining industry has already committed to in its effort to comply with the CAA. Bonner & Moore's estimation of these investment commitments, to date, is about eleven billion dollars to be spent before 1995.

In the second volume of this report (Appendix B, Table B-2), a summary of the of the regional refining capacities used in the 1990 Base Case is presented (secondary units are also detailed). As a reminder, total U.S. nameplate capacity was 16,304 MBSD (stream days), operable was 13,932 MB/D (calender days at 85% utilization rate), and actual processed was 13,409 MB/D.

Also in Appendix B (page B-8), a summary of the announced capacity shutdowns by region and company is given. An estimated 647 MBSD, or 550 MB/D (calender days), **distillation capacity is expected to become unavailable in the following regions:**

Region		**Capacity MB/D**
3		24
5		275
6		35
7		19
9		197
	Total	550

These expected shutdowns, plus some announced distillation expansions (approximately 130 MB/D in Region 5), are included in each corresponding regional model.

When evaluating future conversion capacity needs, each regional LP model generates the need for new distillation and vacuum capacities (at a cost) mainly as a response to refined product demand growth or the need to reinstate shutdown capacity (or both).

The 1990 Base Case crude processed levels (13,409 MB/D), less the expected shutdowns (550 MB/D), plus the announced distillation expansions (130 MB/D), originates a net available total U.S. crude processing capacity from which the forecasted runs are based (12,989

(12,989 MB/D). The summation of all required "new" distillation capacity, by the year 2010 (from the LP model results in the previous section), shows that approximately 1,439 MB/D must be made available in order to comply with refined product demand growth.

This "new" distillation capacity (1,439 MB/D), added to the net available in 1990 (12,989 MB/D), approximates the required refinery runs in 2010 (14,428 MB/D) to meet the refined product demand growth. As a means of verification, our projections in the U.S. Crude Oil Supply and Demand balance (Appendix A, Table A-11) shows a requirement of 14,462 MB/D for refinery runs in 2010 (good!, less than a 1% deviation for results generated by different methodologies).

The meaningful conclusion is that under the "LOW CASE" incremental heavy oil scenario, **no new distillation capacity will have to be built during the twenty year span.** However, utilization rates will have to increase (to approximately 88%), and **the U.S. refining industry will have to spend approximately one billion dollars to refurbish and keep the existing capacity operable during the twenty years.** This figure does not sound unreasonable since the U.S. refining industry currently spends about that amount each year on overall maintenance (includes overhead, which is not a cost contemplated in the LP models).

An alternative to not spending the one billion dollars in refurbishing costs in the twenty year period would be to import **more** refined products over our estimated volumes in this study (2,487 MB/D in the year 2010, as shown in Appendix A, Table A-5). The analysis to evaluate the economic preference between these options is beyond the scope of this study.

In summary, there is a need to build approximately 230 MB/D of new conversion capacity in a twenty year period in order to process the incremental heavy crudes and meet the CAA specifications, incurring approximately 330 million dollars solely for the process units. With plant utilities, the conversion capacity costs amount to approximately 750 million dollars. As a reference, 80 million dollars for a 25 MB/D coking **unit and utilities** (without offsites) seems a conservative market figure.

CONVERSION CAPACITY BY 2010

Region	MB/D
1	17
2 & 3	87
5	100
6	26
Total	**230**

The regional LP models are constrained such that, mathematically, they have limited degrees of freedom, since the question being asked is "what **are** (not should) the necessary investment levels and capacity additions **to** (not try) process incremental heavy oil with declining domestic production and import replacement barrels. **Limited opportunity is allowed to make choices.** A rather inflexible scenario, but consistent with the premises of the study.

Profitability measures to the model's investment figures in this study have no particular economic significance. In RPMS(R) 2000, there are built-in profitability indicators (15% ROI and 35% tax rate), but the generated investments in this study **must be spent** in order to meet the qualitative restrictions on refined product demands and process the crude slate determined in the previous sections.

The LP model's investment figures associated with the capacity requirements perform mathematically as step functions. If we compare two investment levels; e.g., 2000 versus 1995, the difference between the two is the incremental cost of postponing a decision between the two periods. In the twenty year horizon, total investment costs are those reported by the regional model for the year 2010. The industry would have to invest the total dollar amount to comply with refined product demand growth, strict environmental restrictions and a changing crude slate during that time frame.

The total investment requirements shown in **Tables 14 through 17** are details of the following model results:

TOTAL INVESTMENT OF FACILITIES LOW HEAVY OIL PRODUCTION (MM$)				
Proposed Region	**1995**	**2000**	**2005**	**2010**
1	23	91	558	625
2 & 3	57	250	892	1,075
4	3	91	482	538
5	848	890	1,724	1,967
6	301	332	417	425
7	--	--	---	--
9	975	1,511	2,026	2,012
8 & 10	177	227	371	408
Total	**$2,384**	**$3,392**	**$6,470**	**$7,050**

As one would expect, Regions 2, 3, 5, and 9 are the areas with the highest investment requirements because they process the bulk of the incremental heavy oils and are more affected by the CAA regulations.

Considering the 11 billion dollar amount of committed investment (announced or under construction), an additional **7 billion dollars to replace the 2% U.S. domestic production decline with 300 MB/D of "not so bad quality heavy crude," some incremental Saudi Light, and meet the CAA restrictions, seems like a reasonable proposition to be contemplated by the U.S. refining industry.**

This approximate 7 billion dollar investment is, of course, subject to the occurrence of the basic premises in this study. We have chosen a rather conservative approach and, possibly, some policy actions could very well help to make the fundamental assumptions become a reality.

DETAILS OF LP NEW FACILITIES
LOW HEAVY OIL PRODUCTION

REGION 1

MBCD	1995	2000	2005	2010
Crude Distillation	4.0	31.0	65.0	101.0
Vacuum Distillation	17.1	27.2	48.0	67.5
Coking	--	--	10.9	17.4
Oxygenates	--	--	162.3	165.3
Isomerization	--	--	--	--
Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--
Alkylation	--	--	--	--
Hydrotreating	--	--	--	--
Plant Utilities	--	--	--	--

MM$	1995	2000	2005	2010
Crude Distillation	6.9	26.2	42.5	56.5
Vacuum Distillation	16.5	23.4	35.8	46.2
Coking	--	--	22.6	35.8
Oxygenates	--	--	352.0	355.8
Isomerization	--	--	--	--
Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--
Alkylation	--	--	--	--
Hydrotreating	--	--	--	--
Plant Utilities	--	41.8	105.4	131.0
	23.4	91.4	558.3	625.3

REGION 2 & 3

MBCD	1995	2000	2005	2010
Crude Distillation	27.0	97.0	179.0	262.0
Vacuum Distillation	43.9	96.6	155.3	216.4
Coking	--	31.1	60.3	87.0
Oxygenates	--	--	225.4	286.9
Isomerization	--	--	--	--
Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--
Alkylation	--	--	--	--
Hydrotreating	--	--	--	--
Plant Utilities	--	--	--	--

MM$	1995	2000	2005	2010
Crude Distillation	24.0	55.1	82.0	105.1
Vacuum Distillation	33.4	60.5	86.4	110.8
Coking	--	44.7	68.7	87.1
Oxygenates	--	--	451.4	519.3
Isomerization	--	--	--	--
Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--
Alkylation	--	--	--	--
Hydrotreating	--	--	--	--
Plant Utilities	--	90.1	203.9	253.1
	57.4	250.4	892.4	1,075.4

Table 14

DETAILS OF LP NEW FACILITIES
LOW HEAVY OIL PRODUCTION

REGION 4

	MBCD				MM$			
	1995	2000	2005	2010	1995	2000	2005	2010
Crude Distillation	1.0	27.0	60.0	93.0	2.8	24.0	40.3	53.6
Vacuum Distillation	--	28.1	51.3	64.8	--	24.0	37.6	44.8
Coking	--	--	--	--	--	--	--	--
Oxygenates	--	--	110.2	123.5	--	--	296.5	315.4
Isomerization	--	--	--	--	--	--	--	--
Cat Cracking	--	--	--	--	--	--	--	--
Hydrocracking	--	--	--	--	--	--	--	--
Alkylation	--	--	--	--	--	--	--	--
Hydrotreating	--	--	--	--	--	--	--	--
Plant Utilities	--	--	--	--	--	42.5	107.4	124.6
					2.8	90.5	481.8	538.4

REGION 5

	MBCD				MM$			
	1995	2000	2005	2010	1995	2000	2005	2010
Crude Distillation	143.0	287.0	453.0	622.0	70.9	111.5	150.0	184.3
Vacuum Distillation	386.0	349.6	599.2	570.0	171.0	158.7	237.8	229.0
Coking	--	--	83.8	99.6	--	--	85.0	95.1
Oxygenates	299.6	309.6	1,030.6	1,118.2	511.0	521.0	1,097.7	1,162.9
Isomerization	--	--	--	--	--	--	--	--
Cat Cracking	--	--	--	--	--	--	--	--
Hydrocracking	--	--	--	--	--	--	--	--
Alkylation	--	--	--	--	--	--	--	--
Hydrotreating	--	--	--	--	--	--	--	--
Plant Utilities	--	--	--	--	95.3	98.6	153.3	295.6
					848.2	889.8	1,723.8	1,966.9

Table 15

DETAILS OF LP NEW FACILITIES
LOW HEAVY OIL PRODUCTION

REGION 6

	MBCD					MM$			
	1995	2000	2005	2010		1995	2000	2005	2010
Crude Distillation	36.0	46.0	57.0	71.0	Crude Distillation	28.9	33.9	39.0	45.0
Vacuum Distillation	43.8	51.8	60.1	69.8	Vacuum Distillation	33.4	37.9	42.4	47.4
Coking	18.7	21.1	24.8	25.8	Coking	94.6	101.7	110.9	113.6
Oxygenates	--	--	--	--	Oxygenates	--	--	--	--
Isomerization	38.0	38.0	47.9	37.6	Isomerization	100.1	103.7	138.5	107.1
Cat Cracking	--	--	--	--	Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--	Hydrocracking	--	--	--	--
Alkylation	6.9	7.5	7.7	7.7	Alkylation	12.9	13.7	13.9	13.9
Hydrotreating	--	--	--	--	Hydrotreating	--	--	--	--
Plant Utilities	--	--	--	--	Plant Utilities	30.8	41.1	72.0	97.9
						300.7	332.0	416.7	424.9

REGION 9

	MBCD					MM$			
	1995	2000	2005	2010		1995	2000	2005	2010
Crude Distillation	199.0	224.0	252.0	281.0	Crude Distillation	87.9	94.9	102.4	110.0
Vacuum Distillation	160.2	202.8	239.4	260.6	Vacuum Distillation	88.4	105.5	119.5	127.3
Coking	--	--	--	--	Coking	--	--	--	--
Oxygenates	165.9	119.0	347.1	370.2	Oxygenates	374.9	343.4	592.1	623.5
Isomerization	46.1	42.9	40.6	--	Isomerization	69.4	104.9	103.3	--
Cat Cracking	117.1	89.4	64.2	127.6	Cat Cracking	263.7	221.2	178.3	278.9
Hydrocracking	--	63.1	105.3	70.7	Hydrocracking	--	225.4	311.0	242.2
Alkylation	30.7	23.0	106.2	100.9	Alkylation	39.3	93.4	263.5	254.5
Hydrotreating	--	--	--	16.7	Hydrotreating	--	--	--	24.4
Plant Utilities	--	--	--	--	Plant Utilities	51.9	322.4	355.9	350.8
						975.5	1,511.1	2026.0	2,011.6

Table 16

DETAILS OF LP NEW FACILITIES
LOW HEAVY OIL PRODUCTION

REGION 8 & 10

	MBCD			
	1995	2000	2005	2010
Crude Distillation	1.0	1.0	7.0	9.0
Vacuum Distillation	--	3.0	16.2	21.6
Coking	--	--	--	--
Oxygenates	--	1.1	11.7	16.6
Isomerization	--	--	1.4	--
Cat Cracking	8.2	8.7	8.8	6.4
Hydrocracking	4.1	8.9	17.7	22.8
Alkylation	1.7	3.3	6.6	6.5
Hydrotreating	14.4	3.8	--	--
Plant Utilities	--	--	--	--

	MM$			
	1995	2000	2005	2010
Crude Distillation	2.8	2.8	10.0	11.7
Vacuum Distillation	--	4.5	15.9	19.7
Coking	--	--	--	--
Oxygenates	--	11.8	70.5	87.5
Isomerization	--	--	9.0	--
Cat Cracking	46.7	48.5	48.8	39.6
Hydrocracking	40.5	65.7	101.3	119.0
Alkylation	16.0	23.6	39.9	39.5
Hydrotreating	24.3	10.9	--	--
Plant Utilities	47.0	59.1	75.9	91.2
	177.3	226.9	371.3	408.2

Table 17

Clean Air Act Amendment Costs

As requested by NIPER, we have attempted to isolate the economic effects of the Amendments to the Clean Air Act (CAA) from the overall investment figures presented in the previous section. The analysis was focused on the years 2000 and 2010.

Our methodology was based on relaxing the 1995, and beyond, motor gasoline specification constraints to quantities as defined in the 1990 Base Case (regulations to be in effect in 1992) and **zero** reformulated gasoline pool in the total U.S. gasoline demands. The regional LP models were not divergent in any other constraint with the respect to our previous setup ("LOW CASE").

The investment costs generated from these "slackened" model runs should conceptually reflect the investment in "new" conversion capacity needed to solely accommodate incremental heavy oils and meet the projected refined product demands. Theoretically, by difference from the "LOW CASE" results we could estimate the effects of the CAA. We must proceed with caution.

The majority of the properties that characterize intermediate petroleum components suitable for blending into marketable products do not behave, in reality, in a linear fashion. The competition between components from different crudes to become part of a marketable product is driven mainly by the finished product qualities and market prices.

In this particular analysis we are significantly modifying one of the driving forces (product specifications and pool) and, therefore, the model will obviously choose different components to blend products and meet the market demands. Unfortunately, because economics are the driving forces, the models may choose to produce these components with other processes different than those selected in the "LOW CASE." The models are **forced** to run the projected crude slate (the same) and may choose to build new units (different ones) to produce octane components to meet a **different** set of specifications.

Essentially, we present the following results with caution since isolating economic effects with LP models in a stepwise manner can be, at times, misleading for all of the reason previously explained.

For the purposes of trying to approximate the investments associated to only the incremental heavy oil production, we must remind ourselves that the effect of our projected crude import qualities and volumes and demand growth assumptions are also being included.

With these shared concerns brought before the reader, the following investment cost breakdown for the "LOW CASE" is presented.

TOTAL INVESTMENT OF FACILITIES
HEAVY CRUDE VS CLEAN AIR ACT
(LOW HEAVY OIL PRODUCTION BASIS)
(MM $)

Proposed Region	2000 Heavy Crude	2000 CAA	2000 Total Investment	2010 Heavy Crude	2010 CAA	2010 Total Investment
1	89	2	91	248	377	625
2 & 3	249	1	250	545	530	1,075
4	86	5	91	295	243	538
5	393	497	890	743	1,224	1,967
6	324	8	332	414	11	425
7	--	--	--	--	--	--
9	448	1,063	1,511	1,618	394	2,012
8 & 10	138	89	227	301	107	408
Total	**1,727**	**1,665**	**3,392**	**4,164**	**2,886**	**7,050**

A detail of the new investment cost for new facilities with the "LOW CASE" heavy oil production estimates, excluding the CAA restrictions, is presented in **Tables 18 through 21.**

This analysis can provide NIPER with an approximate **assessment** of the amount of capital investment required by the U.S. refining industry associated with the processing of the incremental heavy oil production.

In the twenty year planning period, up to the year 2010, the U.S. industry could be faced with capital expenditures in the 7 billion dollar range, of which 3 billion would be associated with processing the incremental heavy oil production and crude imports, 1 billion to refurbish the existing primary refining capacity to accomadate demand growth, and approximately an additional 3 billion to comply with the regulations of the CAA (over the already commited and announced investments).

DETAILS OF LP NEW FACILITIES
NO CAA AMENDMENTS
(Low Heavy Oil Production Basis)

REGION 1

	MBCD 1995	MBCD 2000	MBCD 2005	MBCD 2010		MM$ 1995	MM$ 2000	MM$ 2005	MM$ 2010
Crude Distillation	--	31.0	--	101.0	Crude Distillation	--	26.2	--	56.5
Vacuum Distillation	--	27.2	--	67.5	Vacuum Distillation	--	23.4	--	46.2
Coking	--	--	--	20.5	Coking	--	--	--	49.9
Oxygenates	--	--	--	0.0	Oxygenates	--	--	--	0.0
Isomerization	--	--	--	--	Isomerization	--	--	--	--
Cat Cracking	--	--	--	--	Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--	Hydrocracking	--	--	--	--
Alkylation	--	--	--	2.1	Alkylation	--	--	--	5.3
Hydrotreating	--	--	--	--	Hydrotreating	--	--	--	--
Plant Utilities	--	--	--	--	Plant Utilities	--	39.7	--	90.3
							89.3		248.2

REGION 2 & 3

	MBCD 1995	MBCD 2000	MBCD 2005	MBCD 2010		MM$ 1995	MM$ 2000	MM$ 2005	MM$ 2010
Crude Distillation	--	97.0	--	262.0	Crude Distillation	--	55.1	--	105.1
Vacuum Distillation	--	96.6	--	216.4	Vacuum Distillation	--	60.5	--	110.8
Coking	--	31.3	--	87.0	Coking	--	44.8	--	87.1
Oxygenates	--	--	--	0.0	Oxygenates	--	--	--	0.0
Isomerization	--	--	--	--	Isomerization	--	--	--	--
Cat Cracking	--	--	--	--	Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--	Hydrocracking	--	--	--	--
Alkylation	--	--	--	--	Alkylation	--	--	--	--
Hydrotreating	--	--	--	29.9	Hydrotreating	--	--	--	32.1
Plant Utilities	--	--	--	--	Plant Utilities	--	88.6	--	210.1
							249.0		545.2

Table 18

DETAILS OF LP NEW FACILITIES
NO CAA AMENDMENTS
(Low Heavy Oil Production Basis)

REGION 4

	MBCD 1995	MBCD 2000	MBCD 2005	MBCD 2010	MM$ 1995	MM$ 2000	MM$ 2005	MM$ 2010
Crude Distillation	--	27.0	--	93.0	--	24.0	--	53.6
Vacuum Distillation	--	21.0	--	64.8	--	19.3	--	44.8
Coking	--	--	--	--	--	--	--	--
Oxygenates	--	--	--	0.0	--	--	--	0.0
Isomerization	--	--	--	35.9	--	--	--	93.2
Cat Cracking	--	--	--	--	--	--	--	--
Hydrocracking	--	--	--	--	--	--	--	--
Alkylation	--	10.5	--	1.7	--	17.6	--	4.5
Hydrotreating	--	--	--	--	--	--	--	--
Plant Utilities	--	--	--	--	--	25.1	--	99.0
						86.0		295.1

REGION 5

	MBCD 1995	MBCD 2000	MBCD 2005	MBCD 2010	MM$ 1995	MM$ 2000	MM$ 2005	MM$ 2010
Crude Distillation	--	287.0	--	622.0	--	111.5	--	184.3
Vacuum Distillation	--	473.6	--	557.4	--	199.3	--	225.2
Coking	--	29.2	--	118.9	--	42.8	--	106.7
Oxygenates	--	0.0	--	0.0	--	0.0	--	0.0
Isomerization	--	--	--	6.8	--	--	--	22.0
Cat Cracking	--	--	--	--	--	--	--	--
Hydrocracking	--	--	--	--	--	--	--	--
Alkylation	--	--	--	--	--	--	--	--
Hydrotreating	--	--	--	--	--	--	--	--
Plant Utilities	--	--	--	--	--	39.6	--	205.2
						393.2		743.4

Table 19

DETAILS OF LP NEW FACILITIES
NO CAA AMENDMENTS
(Low Heavy Oil Production Basis)

REGION 6

	MBCD 1995	MBCD 2000	MBCD 2005	MBCD 2010
Crude Distillation	--	46.0	--	71.0
Vacuum Distillation	--	51.8	--	69.8
Coking	--	22.1	--	26.1
Oxygenates	--	--	--	--
Isomerization	--	37.1	--	37.0
Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--
Alkylation	--	7.1	--	8.2
Hydrotreating	--	--	--	--
Plant Utilities	--	--	--	--

	MM$ 1995	MM$ 2000	MM$ 2005	MM$ 2010
Crude Distillation	--	33.9	--	45.0
Vacuum Distillation	--	37.9	--	47.4
Coking	--	103.9	--	114.1
Oxygenates	--	--	--	--
Isomerization	--	95.8	--	104.3
Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--
Alkylation		13.1		14.6
Hydrotreating	--	--	--	--
Plant Utilities	--	39.3	--	88.6
		323.9		414.0

REGION 9

	MBCD 1995	MBCD 2000	MBCD 2005	MBCD 2010
Crude Distillation	--	224.0	--	281.0
Vacuum Distillation	--	202.8	--	260.6
Coking	--	--	--	--
Oxygenates	--	0.0	--	0.0
Reforming	--	29.0	--	16.6
Cat Cracking	--	19.4	--	94.8
Hydrocracking	--	--	--	86.5
Alkylation	--	4.2	--	147.2
Hydrotreating	--	40.6	--	--
Plant Utilities	--	--	--	--

	MM$ 1995	MM$ 2000	MM$ 2005	MM$ 2010
Crude Distillation	--	94.9	--	110.0
Vacuum Distillation	--	105.5	--	127.3
Coking	--	--	--	--
Oxygenates	--	0.0	--	0.0
Reforming	--	64.4	--	45.0
Cat Cracking	--	81.9	--	229.9
Hydrocracking	--	--	--	274.9
Alkylation	--	8.9	--	563.2
Hydrotreating	--	38.6	--	--
Plant Utilities	--	54.2	--	267.9
		448.4		1,618.2

Table 20

DETAILS OF LP NEW FACILITIES
NO CAA AMENDMENTS
(Low Heavy Oil Production Basis)

REGION 8 & 10

	MBCD 1995	MBCD 2000	MBCD 2005	MBCD 2010
Crude Distillation	--	1.0	--	9.0
Vacuum Distillation	--	0.9	--	21.6
Coking	--	--	--	--
Oxygenates	--	0.0	--	0.0
Reforming	--	0.5	--	3.3
Cat Cracking	--	17.6	--	10.0
Hydrocracking	--	--	--	17.8
Alkylation	--	--	--	1.8
Hydrotreating	--	7.9	--	--
Plant Utilities	--	--	--	--

	MM$ 1995	MM$ 2000	MM$ 2005	MM$ 2010
Crude Distillation	--	2.8	--	11.7
Vacuum Distillation	--	1.8	--	19.7
Coking	--	--	--	--
Oxygenates	--	0.0	--	0.0
Reforming	--	6.9	--	21.6
Cat Cracking	--	76.9	--	53.1
Hydrocracking	--	--	--	101.6
Alkylation	--	--	--	15.1
Hydrotreating	--	16.9	--	--
Plant Utilities	--	32.7	--	78.7
		138.0		301.5

Table 21

SECTION 2

SENSITIVITY ANALYSIS

HIGH INCREMENTAL HEAVY OIL PROJECTIONS

General Comments

Our analysis of the "LOW CASE" incremental heavy oil projections demonstrated the need for the U.S. refining industry to invest approximately 7 billion dollars in the next twenty years to, essentially, "remain in business," should all the premises of the study materialize.

Furthermore, a breakdown of this total cost shows that approximately 3 billion dollars can be associated to processing the incremental heavy domestic oil (300 MB/D in 2010) if one accepts that a significant portion of the costs is also attributable to processing crude imports.

There is a request by NIPER to further separate these 3 billion investment dollars in an effort to isolate the costs directly associated with processing the domestic incremental heavy oil. There is no uncomplicated way to generate this estimate, since crude imports are **required** to meet the refined product demands. Unless another source of crude becomes readily available, this dependency by the U.S. refining industry is another **fundamental** assumption of the study.

In an attempt to set this request in perspective, we trust that the following comments will be helpful.

For the U.S. refining industry to equip itself to process 300 MB/D of heavy oils is, in reality, not a colossal challenge. This is confirmed by the fact that only 230 MB/D of additional conversion capacity is required (a meager 13% boost over the existing capacity), and the vast increase is in areas which traditionally have not required this type of conversion process. The associated cost to build this new capacity is estimated by the LP models at approximately 330 million dollars. As explained before, these costs are solely for the units and do not include offsites. With the plant utilities, the new conversion capacity costs amount to approximately 750 million dollars.

Some of the necessity for conversion capacity also arises from the need to process heavier vacuum bottoms from imported crudes. The foreign incremental supplies to the regional LP models are Middle Eastern light crude (32.9 degrees API and 1.8% sulphur) and some South American medium crudes (24.8 degrees API and 1.8% sulphur). The vacuum bottoms (1050 degrees Fahrenheit) of these crudes have certain critical properties comparable to those of a few domestic heavy crude oils of considerably less gravity and sulphur content. Essentially, replacement of declining domestic ANS and light sweet production with these foreign incremental crudes and additional heavy oils requires the conversion capacity as indicated by the regional models.

The incremental 300 MB/D of heavy oils are a small percent (2%) of the total refinery crude runs forecasted for the year 2010 (14,462 MB/D). It is also an equally small proportion of crude import volumes (3%) and of domestic production (7%) in 2010. Using any of these proportional relationships, it could be possible to theorize on an estimate of the costs directly attributable to the incremental domestic heavy oils. However, in reality, there is no validity in using any of these proportional relationships for such an estimate.

In summary, the costs associated with processing the heavy oils in the "LOW CASE" are approximately 3 billion dollars, to be disbursed in a twenty year span, in addition to those costs needed to comply with CAA and to refurbish the existing distillation capacity to keep up with demand growth. Approximately 750 million dollars of the 3 billion are investments for conversion capacity, and the balance for octane component production and intermediate streams quality treatment.

NIPER has provided a projection of heavy oil production estimates which exceed the previous "LOW CASE" estimates by more than 600 MB/D in the year 2010. We have labeled the following analysis "HIGH CASE" and will begin by examining the major differences in production rates between this alternate "HIGH CASE" and our previous estimates.

Volume Estimates

The volume estimates, up to the year 2000, under this high scenario (**Table 22**) do not differ significantly from the figures in our previous analysis. Therefore, it was not necessary to re-run the regional LP models to estimate investment costs for the years 1995 and 2000, since the only additional meaningful heavy oil volume occurs in Region 5 and is less than 1% of the projected refinery runs. These differences are undetectable by the regional models.

We suppose that the basic assumptions that were clearly stated by NIPER for the "LOW CASE" production rates also hold for these higher estimates. In particular, we are concerned with a U.S. refining industry operating in a free world economy and that environmental regulations continue to prevent the construction of new grass root heavy oil refineries.

These two premises are very important, since they support our study in the need to make up regional crude shortfalls (because of declining domestic production) with excess crude from other areas in order to meet the refined product demands.

The most salient aspect of the high production rate estimates is the 930 MB/D of additional heavy oil projected to become available by the year 2010; a lofty 630 MB/D increase versus the previous low estimates (**Table 23**). Also, more than half of this volume occurs in Region 5 (Gulf states), qualitatively represented in the LP model as a crude with 19.5 degrees API and 0.68% sulphur; a heavy crude, but of good quality versus the incremental supplies of what is being imported to that particular region.

The additional volumes that make up the 630 MB/D are small quantities in Region 2, 3 and 6, and nearly 200 MB/D in California's San Joaquin Valley (Regions 8 & 10). However, most of this latter additional volume is processed in other California areas (Regions 4 and 9) as traditionally has been the case.

ALTERNATE HIGH HEAVY OIL PRODUCTION RATES THROUGH 2010

Proposed Region	General Location	DOE Estimates of Incremental Domestic Heavy Oil Production MB/D As of 1990	MB/D As of 1995	MB/D As of 2000	MB/D As of 2005	MB/D As of 2010
1	East Coast	0	0	0	0	0
	Incremental Production Rate	--	0	0	0	0
2	Upper Midwest	0.25	0.25	0.35	0.75	1.25
	Incremental Production Rate	--	0	0.10	0.40	0.50
3	Midwest (OK, KS, MS)	4.18	5.18	6.18	7.18	9.18
	Incremental Production Rate	--	1.00	1.00	1.00	2.00
4	West Coast (except Regions 8, 9, 10)	0.25	0.25	0.25	0.25	0.25
	Incremental Production Rate	--	0	0	0	0
5	Gulf States	63.96	75.96	120.46	262.46	618.96
	Incremental Production Rate	--	12.00	44.50	142.00	356.50
6	Rocky Mt. Region	20.25	21.25	30.25	40.25	60.25
	Incremental Production Rate	--	1.00	9.00	10.00	20.00
7	Alaska	0	0	1.00	5.00	30.00
	Incremental Production Rate	--	0	1.00	4.00	25.00
8	California Coastal Region	63.80	93.80	113.80	138.80	163.80
	Incremental Production Rate	--	30.00	20.00	25.00	25.00
9	Los Angeles Basin	89.90	84.90	79.90	87.90	88.90
	Incremental Production Rate	--	-5.00	-5.00	8.00	1.00
10	San Joaquin Valley	500.60	525.60	550.60	600.60	700.60
	Incremental Production Rate	--	25.00	25.00	50.00	100.00
	Total Production Rate	**743.19**	**807.19**	**902.79**	**1,143.19**	**1,673.19**
	Total Incremental Production Rate	**0**	**64.00**	**159.60**	**400.00**	**930.00**

Table 22

ESTIMATES OF INCREMENTAL DOMESTIC HEAVY OIL
ALTERNATE HIGH VS LOW PRODUCTION RATES
MB/D

Proposed Region		----- As of 1995 ----- High	Low		----- As of 2000 ----- High	Low		----- As of 2005 ----- High	Low		----- As of 2010 ----- High	Low	
1	East Coast	0	0	--	0	0	--	0	0	--	0	0	--
2 & 3	Midwest	5.43	5.43	--	6.53	6.43	0.10	7.93	7.43	0.50	10.43	9.43	1.00
4	West Coast	0.25	0.25	--	0.25	0.25	--	0.25	0.25	--	0.25	0.25	--
5	Gulf Coast	75.96	74.96	1.00	120.46	108.96	11.50	262.46	159.96	102.50	618.96	260.96	358.00
6	Rocky Mountain	21.25	21.25	--	30.25	25.25	5.00	40.25	28.25	12.00	60.25	28.25	32.00
7	Alaska	0	0	--	1.00	0	1.00	5.00	1.00	4.00	30.00	5.00	25.00
9	Los Angeles Basin	84.90	84.90	--	79.90	79.90	--	87.90	74.90	13.00	88.90	69.90	19.00
8 & 10	San Joaquin Valley	619.40	619.40	--	664.40	664.40	--	739.40	677.40	62.00	864.40	669.40	195.00
	Total	807.19	806.19	1.00	902.79	885.19	17.60	1,143.19	949.19	194.00	1,673.19	1,043.19	630.00

Table 23

CRUDE SUPPLIES FOR LP MODELS

Estimates for 2005 and 2010

The balancing criteria used to equalize the crude supplies between the different regions for the years 2005 and 2010 are quite similar to those utilized in the low production rates scenario. The main difference lies in the fact that in this "HIGH CASE", the incremental domestic heavy oil production is assumed to volumetrically back out equal amounts of imported crude, mainly Middle Eastern light sour.

The primary reason to base the crude supply estimates for the regional LP models (high production rates scenario) on the premise that the additional domestic heavy oil displaces Middle Eastern type crudes, arises from the undeniable fact that this crude quality will be the United States' and world's incremental supplies for years to come. The next in line to supply the U.S refineries are the South American crude producers, whom we believe will always be in a better position (proximity and lower quality) to react with price actions (lower them) to guarantee their crudes a secure outlet in the U.S. marketplace.

The crude representation for the LP models under the high production rates scenario (**Tables 24 and 25**) can be compared with the low production rates estimates (**Table 8 and 9**). Note that the Middle Eastern crude supplies in the former are reduced by an equal amount of incremental domestic heavy oil availabilities (small differences arise due to rounding since these projections were done on an electronic spreadsheet).

In the years 2005 and 2010 balanced crude estimates for the LP models, there are two inter-regional transfers of incremental domestic heavy oils: from Region 5 (Gulf Coast) to Region 2 (Midwest), and from Regions 8 and 10 (San Joaquin Valley) to Region 9 and 4 (Los Angeles Basin and San Francisco area). All other incremental heavy oil volumes are processed in the region where they are being produced.

CRUDE REPRESENTATION FOR REGIONAL LP MODELS

ALTERNATE BALANCED 2005

REGION	MB/D	VOL FRAC	API	%S	PROPOSED DOE REGION 1	2	3	4	5	6	7	8	9	10	TOTAL
East Light	0	0.000	51.6	0.26	0	0	0	0	0	0	0	0	0	0	0
Cushing Sweet	720	0.051	39.4	0.42	0	290	88	0	185	158	0	0	0	0	720
Mid West Sour	213	0.015	25.1	2.55	0	99	0	0	0	114	0	0	0	0	213
Mid West Hvy	7	0.000	18.8	1.98	0	0	7	0	0	0	0	0	0	0	7
Rocky Mt Hvy	40	0.003	19.8	3.30	0	0	0	0	0	40	0	0	0	0	40
West Texas Int.	870	0.062	40.5	0.35	0	222	163	0	485	0	0	0	0	0	870
Lousiana Sweet	1568	0.111	35.8	0.36	0	395	136	0	1037	0	0	0	0	0	1568
Gulf C Heavy	262	0.019	19.5	0.63	0	61	0	0	201	0	0	0	0	0	262
Alaska No Slope	665	0.047	27.6	1.12	0	6	38	276	128	0	82	0	137	0	665
California Med	294	0.021	28.7	0.68	0	0	0	38	0	0	0	0	180	76	294
California Hvy	826	0.059	13.1	1.21	0	0	0	423	0	0	0	9	356	38	826
Canada Blend	640	0.045	29.8	1.29	60	509	0	10	7	55	0	0	0	0	640
So America Med	1962	0.139	24.8	1.85	257	0	0	245	1176	0	0	0	284	0	1962
So America Hvy	293	0.021	16.5	2.40	139	0	0	1	153	0	0	0	0	0	293
Middle East	4416	0.313	32.9	1.80	540	733	270	211	2394	116	152	0	0	0	4416
Africa	900	0.064	35.4	0.17	300	107	0	0	493	0	0	0	1	0	900
Europe	200	0.014	37.6	0.40	54	22	14	0	110	0	0	0	0	0	200
Asia	210	0.015	39.5	0.10	0	5	0	49	0	0	15	0	141	0	210
	14087	1.000		SUPPLY	1349	2449	716	1253	6366	462	249	9	1099	114	14087
				TARGET	1350	2448	716	1254	6366	463	249	9	1099	113	14087

Table 24

CRUDE REPRESENTATION FOR REGIONAL LP MODELS

ALTERNATE BALANCED 2010

					PROPOSED DOE REGION										
REGION	MB/D	VOL FRAC	API	%S	1	2	3	4	5	6	7	8	9	10	TOTAL
East Light	0	0.000	51.6	0.26	0	0	0	0	0	0	0	0	0	0	0
Cushing Sweet	564	0.039	39.4	0.42	0	227	69	0	145	124	0	0	0	0	564
Mid West Sour	203	0.014	25.1	2.55	0	95	0	0	0	109	0	0	0	0	203
Mid West Hvy	9	0.001	18.8	1.98	0	0	9	0	0	0	0	0	0	0	9
Rocky Mt Hvy	60	0.004	19.8	3.30	0	0	0	0	0	60	0	0	0	0	60
West Texas Int.	776	0.054	40.5	0.35	0	198	145	0	433	0	0	0	0	0	776
Lousiana Sweet	1398	0.097	35.8	0.36	0	352	121	0	924	0	0	0	0	0	1398
Gulf C Heavy	619	0.043	19.5	0.63	0	145	0	0	474	0	0	0	0	0	619
Alaska No Slope	430	0.030	27.1	1.12	0	4	25	178	82	0	53	0	89	0	430
California Med	286	0.020	28.7	0.68	0	0	0	37	0	0	0	0	182	67	286
California Hvy	953	0.066	13.1	1.21	0	0	0	493	0	0	0	9	402	49	953
Canada Blend	640	0.044	29.8	1.29	60	509	0	10	7	55	0	0	0	0	640
So America Med	2110	0.146	24.8	1.85	257	0	0	295	1245	0	0	0	313	0	2110
So America Hvy	315	0.022	16.5	2.40	149	0	0	1	164	0	0	0	0	0	315
Middle East	4789	0.331	32.9	1.80	566	851	352	225	2458	148	188	0	0	0	4788
Africa	900	0.062	35.4	0.17	300	107	0	0	493	0	0	0	1	0	900
Europe	200	0.014	37.6	0.40	54	22	14	0	110	0	0	0	0	0	200
Asia	210	0.015	39.5	0.10	0	5	0	49	0	0	15	0	141	0	210
	14462	1.000		SUPPLY	1366	2514	735	1288	6535	495	256	9	1128	116	14462
				TARGET	1365	2513	736	1288	6536	496	256	9	1128	116	14462

Table 25

ESTIMATED CONVERSION CAPACITY REQUIREMENTS

Regional LP Models Results

The basic underlying premises affecting refined product demands set forth in our "LOW CASE" scenario for the regional LP models continue to be in effect for the subsequent results. The only change introduced for this analysis is the new crude refinery intake slates with the high heavy oil production rates.

Regional LP model results indicate that an additional 80 MB/D of new conversion capacity will be required by the year 2010, versus our "LOW CASE" findings (230 MB/D) to process the additional 630 MB/D of domestic heavy crude. This is a relatively small amount for such an increment of additional domestic heavy oils production.

CONVERSION CAPACITY BY 2010

Region	MB/D High	MB/D Low	MB/D ▲
1	17	17	--
2 & 3	90	87	3
4	11	--	11
5	162	100	62
6	30	26	4
Total	310	230	80

The main reason for this result stems on the assumption on the quality of the crude being replaced by the new domestic heavy oils. As mentioned above, both the gravity and the sulphur levels of the **bulk** of the additional domestic oil is of a desirable quality from a refiner's point of view, especially in terms of its sulphur content. Middle Eastern crudes are sour (1.8% sulphur) while the majority of the additional domestic heavy oil is essentially on the sweet side of the scale (0.63% sulphur), although nearly 200 MB/D of California heavy sour is also being processed (reflects the need for additional conversion capacity in Region 4).

As expected, most of the additional conversion capacity requirements are in Region 5 where more than half of the 630 MB/D additional production estimate occurs. This capacity requisite in Region 5 responds also to the need to accommodate the refinery configuration for the loss in gravity, as Middle Eastern type crude (32.9 degree API) is being replaced by a "not so bad" domestic heavy oil (19.5 degrees API).

The capital investment for the 310 MB/D of conversion capacity to process the additional heavy oils from the high production rate estimates by the year 2010 is approximately 1 billion dollars, which incorporates the plant utilities costs (no offsites included).

As in the previous case, there is no need for additional distillation capacity rather increase operating rates at similar levels as in the "LOW CASE." The costs to maintain the distillation capacity operable towards the next twenty years is also in the 1 billion dollar range.

In summary, the U.S. refining industry could be faced with capital expenditures in the 7 billion dollar range, of which approximately 1 billion would be to maintain operable the existing capacity, another 1 billion to build the necessary conversion capacity to accommodate the additional domestic oils and crude imports, and the balance to comply with the Amendments to the Clean Air Act (CAA) and quality treatment of intermediate streams (**Tables 26 to 29**).

Investment Comparison- High versus Low Production Rates

There is a relatively low difference in the estimated required investment levels between the "HIGH" and "LOW CASES" being evaluated (**Table 30**). In a twenty year span, the difference amounts to only 203 million dollars

The results are not surprising, since this "HIGH CASE," in reality, is a sensitivity to our previous analysis and, in reality, does not involve processing any additional barrels. **The economic impact being determined on the regional refineries are those associated with a quality switch in their crude intake.** We are not determining the investment impact of an additional production to the refineries, rather the replacement of a light sour crude with a heavier crude (12 degrees API lower), but significantly sweeter (a full 1% less sulphur).

The regional models indicate that although there seems to be a detriment in the quality switch (reflected in the need for additional vacuum capacity) (**Tables 31 and 32**), there are significant savings in investments for treatment of intermediate streams and sulphur recovery costs.

Results from the regional models indicate that under the premises for the "HIGH CASE," by the year 2010, the U.S. refining industry would be faced with an investment still in the 7 billion dollar range if it is trusted with the responsibility of processing the 930 MB/D of heavy oil production as estimated by NIPER. The breakdown would also be similar to our results determined for the "LOW CASE," with the exception that approximately 1 billion dollars must be invested in conversion capacity to process these incremental barrels.

SUMMARY OF LP MODEL RESULTS
HIGH HEAVY OIL PRODUCTION
Years 2005 & 2010
(unless otherwise noted)

	Region 1				
	1990	1995	2000	2005	2010 (No Change)
Refinery Crude Intake, MBCD					
Domestic	13	9	4	0	0
Imports	1,272	1,280	1,312	1,349	1,386
Total	1,285	1,289	1,316	1,349	1,386
Calculated Gravity, API					
Base Case	31.1	31.1	31.1	31.1	31.1
New Heavy Oil	--	30.2	30.4	30.3	30.2
Major Products, MBCD					
Gasoline	641	696	692	706	722
Light Distillate	91	111	118	128	138
Middle Distillate	256	220	236	290	297
Fuel Oil	147	146	145	145	145
Capacity Added, MBCD					
Crude Distillation	--	4	31	65	101
Vacuum Distillation	--	17	27	48	67
Bottoms Conversion	--	0	0	11	17
Motor Fuel Quality	--	0	0	162	165
Capital Investment, MM$	--	23	91	558	625

	Regions 2 & 3				
	1990	1995	2000	2005	2010 (Only)
Refinery Crude Intake, MBCD					
Domestic	2,091	1,903	1,698	1,482	1,388
Imports	921	1,112	1,387	1,685	1,862
Total	3,012	3,015	3,085	3,167	3,250
Calculated Gravity, API					
Base Case	34.5	34.5	34.5	34.5	34.5
New Heavy Oil	--	35.0	34.6	34.2	33.5
Major Products, MBCD					
Gasoline	1,789	1,791	1,797	1,835	1,875
Light Distillate	200	235	259	282	303
Middle Distillate	709	725	746	789	832
Fuel Oil	64	64	62	62	63
Capacity Added, MBCD					
Crude Distillation	--	27	97	179	262
Vacuum Distillation	--	44	97	155	236
Bottoms Conversion	--	0	31	60	90
Motor Fuel Quality	--	0	0	225	293
Capital Investment, MM$	--	57	250	892	1,080

Table 26

SUMMARY OF LP MODEL RESULTS
HIGH HEAVY OIL PRODUCTION
Years 2005 & 2010
(unless otherwise noted)

Region 4	1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD					
Domestic	1,101	1,008	853	732	708
Imports	93	187	368	522	579
Total	1,194	1,195	1,221	1,254	1,287
Calculated Gravity, API					
Base Case	24.3	24.3	24.3	24.3	24.3
New Heavy Oil	--	24.1	23.7	23.5	22.8
Major Products, MBCD					
Gasoline	594	594	581	594	608
Light Distillate	170	211	225	245	265
Middle Distillate	225	207	210	222	233
Fuel Oil	165	159	159	161	162
Capacity Added, MBCD					
Crude Distillation	--	1	27	60	93
Vacuum Distillation	--	0	28	65	109
Bottoms Conversion	--	0	0	0	11
Motor Fuel Quality	--	0	0	110	124
Capital Investment, MM$	--	3	91	488	616

Region 5	1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD					
Domestic	2,745	2,522	2,244	2,034	2,058
Imports	3,315	3,534	3,956	4,332	4,477
Total	6,060	6,056	6,200	6,366	6,535
Calculated Gravity, API					
Base Case	33.1	33.1	33.1	33.1	33.1
New Heavy Oil	--	32.7	32.5	31.9	31.2
Major Products, MBCD					
Gasoline	3,123	3,286	3,245	3,316	3,392
Light Distillate	668	823	880	956	1,031
Middle Distillate	1,260	1,130	1,220	1,451	1,531
Fuel Oil	362	351	351	354	357
Capacity Added, MBCD					
Crude Distillation	--	143	287	453	622
Vacuum Distillation	--	386	350	596	712
Bottoms Conversion	--	0	0	89	162
Motor Fuel Quality	--	300	310	1,025	1,130
Capital Investment, MM$	--	848	890	1,724	2,007

Table 27

SUMMARY OF LP MODEL RESULTS
HIGH HEAVY OIL PRODUCTION
Years 2005 & 2010
(unless otherwise noted)

Region 6	1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD					
Domestic	405	363	331	312	293
Imports	55	98	140	170	203
Total	460	461	471	482	496
Calculated Gravity, API					
Base Case	35.5	35.5	35.5	35.5	35.5
New Heavy Oil	--	32.8	32.5	31.7	30.8
Major Products, MBCD					
Gasoline	248	247	246	243	239
Light Distillate	27	34	36	39	42
Middle Distillate	122	112	121	125	140
Fuel Oil	8	8	8	8	8
Capacity Added, MBCD					
Crude Distillation	--	36	46	57	71
Vacuum Distillation	--	44	52	62	76
Bottoms Conversion	--	19	21	26	30
Motor Fuel Quality	--	45	46	53	43
Capital Investment, MM$	--	301	332	418	454

Region 7	1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD					
Domestic	217	182	131	81	53
Imports	20	55	111	168	203
Total	237	237	242	249	256
Calculated Gravity, API					
Base Case	29.5	29.5	29.5	29.5	29.5
New Heavy Oil	--	29.5	30.5	31.5	32.0
Major Products, MBCD					
Gasoline					
Light Distillate					
Middle Distillate					
Fuel Oil					
Capacity Added, MBCD					
Crude Distillation					
Vacuum Distillation					
Bottoms Conversion					
Motor Fuel Quality					
Capital Investment, MM$					

Table 28

SUMMARY OF LP MODEL RESULTS
HIGH HEAVY OIL PRODUCTION
Years 2005 & 2010
(unless otherwise noted)

Region 9	1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD					
Domestic	855	815	739	674	674
Imports	191	231	332	425	454
Total	1,046	1,046	1,071	1,099	1,128
Calculated Gravity, API					
Base Case	26.3	26.3	26.3	26.3	26.3
New Heavy Oil	--	25.6	24.7	23.9	23.3
Major Products, MBCD					
Gasoline	549	605	629	695	799
Light Distillate	149	185	197	215	232
Middle Distillate	175	127	183	194	150
Fuel Oil	145	140	139	140	142
Capacity Added, MBCD					
Crude Distillation	--	199	224	252	281
Vacuum Distillation	--	160	203	244	275
Bottoms Conversion	--	0	0	0	0
Motor Fuel Quality	--	360	377	668	698
Capital Investment, MM$	--	976	1,511	2,043	2,063

Regions 8 & 10	1990	1995	2000	2005	2010 (No Change)
Refinery Crude Intake, MBCD					
Domestic	116	117	117	123	125
Imports	0	0	0	0	0
Total	116	117	117	123	125
Calculated Gravity, API					
Base Case	26.4	26.4	26.4	26.4	26.4
New Heavy Oil	--	23.9	23.7	23.4	22.4
Major Products, MBCD					
Gasoline	28	34	35	50	52
Light Distillate	16	20	21	23	25
Middle Distillate	26	26	26	28	30
Fuel Oil	16	16	16	17	17
Capacity Added, MBCD					
Crude Distillation	--	1	1	7	9
Vacuum Distillation	--	0	3	16	22
Bottoms Conversion	--	0	0	0	0
Motor Fuel Quality	--	28	26	46	52
Capital Investment, MM$	--	177	227	371	408

Table 29

TOTAL INVESTMENT OF FACILITIES
ALTERNATE HIGH VS LOW PRODUCTION RATES
(MM $)

Proposed Region	2005 High	2005 Low		2010 High	2010 Low	
1	558	558	--	625	625	--
2 & 3	892	892	--	1,080	1,075	5
4	488	482	6	616	538	78
5	1,724	1,724	--	2,007	1,967	40
6	418	417	1	454	425	29
7	--	--	--	--	--	--
9	2,043	2,026	17	2,063	2,012	51
8 & 10	371	371	--	408	408	--
Total	6,494	6,470	24	7,253	7,050	203

Table 30

RESULTS COMPARISON SUMMARY
(HIGH) - (LOW) HEAVY OIL PRODUCTION
Years 2005 & 2010

	Region 1 2005	Region 1 2010		Regions 2 & 3 2005	Regions 2 & 3 2010
Refinery Crude Intake, MBCD			**Refinery Crude Intake, MBCD**		
Domestic	No Change	No Change	Domestic	No Change	84
Imports			Imports		-84
Capacity Added, MBCD			**Capacity Added, MBCD**		
Crude Distillation			Crude Distillation		0
Vacuum Distillation			Vacuum Distillation		20
Bottoms Conversion			Bottoms Conversion		3
Motor Fuel Quality			Motor Fuel Quality		6
Capital Investment, MM$			**Capital Investment, MM$**		5

	Region 4 2005	Region 4 2010		Regions 5 2005	Regions 5 2010
Refinery Crude Intake, MBCD			**Refinery Crude Intake, MBCD**		
Domestic	45	134	Domestic	79	280
Imports	-45	-134	Imports	-79	-280
Capacity Added, MBCD			**Capacity Added, MBCD**		
Crude Distillation	0	0	Crude Distillation	0	0
Vacuum Distillation	14	44	Vacuum Distillation	-3	142
Bottoms Conversion	0	11	Bottoms Conversion	5	62
Motor Fuel Quality	0	0	Motor Fuel Quality	-6	12
Capital Investment, MM$	6	78	**Capital Investment, MM$**	0	40

Table 31

RESULTS COMPARISON SUMMARY
(HIGH) - (LOW) HEAVY OIL PRODUCTION
Years 2005 & 2010

	Region 6 2005	Region 6 2010		Regions 7 2005	Regions 7 2010
Refinery Crude Intake, MBCD			**Refinery Crude Intake, MBCD**		
Domestic	12	32	Domestic	No Change	4
Imports	-12	-32	Imports		-4
Capacity Added, MBCD			**Capacity Added, MBCD**		
Crude Distillation	0	0	Crude Distillation		--
Vacuum Distillation	2	6	Vacuum Distillation		--
Bottoms Conversion	1	4	Bottoms Conversion		--
Motor Fuel Quality	-3	-2	Motor Fuel Quality		--
Capital Investment, MM$	1	29	**Capital Investment, MM$**		--

	Region 9 2005	Region 9 2010		Regions 8 & 10 2005	Regions 8 & 10 2010
Refinery Crude Intake, MBCD			**Refinery Crude Intake, MBCD**		
Domestic	29	95	Domestic	No Change	No Change
Imports	-29	-95	Imports		
Capacity Added, MBCD			**Capacity Added, MBCD**		
Crude Distillation	0	0	Crude Distillation		
Vacuum Distillation	5	14	Vacuum Distillation		
Bottoms Conversion	0	0	Bottoms Conversion		
Motor Fuel Quality	5	11	Motor Fuel Quality		
Capital Investment, MM$	17	51	**Capital Investment, MM$**		

Table 32

BONNER & MOORE PROJECT 3MS91-582

Appendix II

Volume II

REFINERY EXPANSION EVALUATION
FOR U.S. HEAVY OIL RECOVERY

Assessment of Market Capacity
for Specific Regions with Predefined Increases
in Heavy Oil
for the Years 1992 through 2010

VOLUME II

Performed for

the National Institute for Petroleum Research
Bartlesville, Oklahoma

February 1992

Bonner & Moore Project #MS91-582

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SECTION 1

WORLD PETROLEUM BALANCE

Throughout this forecast we have made every attempt to be as thorough and accurate as possible without missing the major points and implications. As a starting point, we have consistently kept our assumptions conservative and reasonable. We have placed equal weight on the historical trends and the highly probable future changes from trends that we have been able to identify.

Our goal was to produce a consistent, thorough, and reasonable supply/demand forecast specifically for the United States, with additional, more general, forecasts for Europe and the Far East, which can serve as a consistent basis for a regional crude and refined products price forecast.

WORLD PETROLEUM DEMAND

In this section, we use the following terms:

Consumption is production, plus stock change, plus imports, minus exports, plus international marine bunkers (gasoil or distillate, and resid or heavy fuel oil). Hence, trade flows are taken into account. Consumption figures are IEA data through 1988 for the non-OECD countries, and IEA data through 1989 for the OECD countries. Consumption figures beyond these points through 1991 are based on IEA data for "apparent demand." We have made adjustments to account for trade flows in order to arrive at the underlying consumption figures. Consumption figures for 1992 and beyond are based on the analyses of Bonner & Moore Market Consultants.

Demand (the numbers called **consumption** in the *IEA Quarterly* and the *Monthly IEA Oil Market Report*) is production, plus stock change, plus international marine bunkers. Hence, trade flows are not taken into account, and the numbers called *consumption* in these reports will not match up (as they should not) with the consumption figures in this forecast for the post 1988 time period.

The tables which substantiate the views offered in this study appear at the end of this section under the heading, **Addendum to Section 1.**

PETROLEUM GROWTH PATTERNS

World Petroleum Growth Patterns

Three trends in total petroleum growth patterns are apparent from viewing the historical growth rate data (**Figure A-1**). From 1981 to 1990, world growth rates (both positive and negative) have been getting smaller. Historically, the OECD growth rate has been below that of the total world. The differences between OECD and non-OECD have been declining, with little difference in relative growth rates since 1983. In general, these three trends are projected to continue throughout the forecast period.

Despite all the publicity about the growth rates of Third World and Pacific Rim countries, since 1983 world petroleum product consumption, on a percentage of total world basis, has been remarkably steady, with the OECD countries consuming slightly over 55% (**Figure A-2**).

This stability in world petroleum energy share is forecast to remain virtually unchanged through the forecast period.

In 1992 and continuing throughout the planning period, we are forecasting the world's economy to return to a modest growth track, as was begun in 1991. We expect total petroleum consumption to recover, averaging slightly below 1% growth in 1992, slightly above 1% in 1993, and then close to 1.5% for 1994 through 1998 (**Table A-1**).

During the period from 1995 through 1998, we see OPEC capacity utilization increasing, reaching 88.6% utilization in 1998. At this point, although we are not forecasting a supply-limited environment, with the high utilization rates as in the past, we expect another political event within the oil exporting nations to occur which temporarily restrains supplies sufficiently to cause a sharp price jump in real dollar terms (see the **Supply** section of this document for complete details). This price spike is followed (as has been the case in the past) by a decline in consumption and a decline in prices in real dollar terms.

Therefore, we are forecasting total world consumption to decline in 1999 by close to 1.8%. We do not expect a greater degree of decline, as was the case in 1980, as the structure of the market has changed since then. Due to economics, the amount of resid used in quickly switchable or dual fired boiler service is no longer large enough to have a price spike cause a negative 4% growth rate, as was the case in 1980.

After the 1998 price spike and reaction occur, total world demand is expected to recover, but to a slightly lower growth rate than before the price spike. Since 1971, each price spike has resulted in a permanent lowering of the rate of growth of petroleum products demand. We foresee no reason for this trend not to continue in the future.

Therefore, we are forecasting a recovery in the total world growth rate to be flat in 2000, slightly under 1% in 2001, and close to 1.25% in 2006 through 2010.

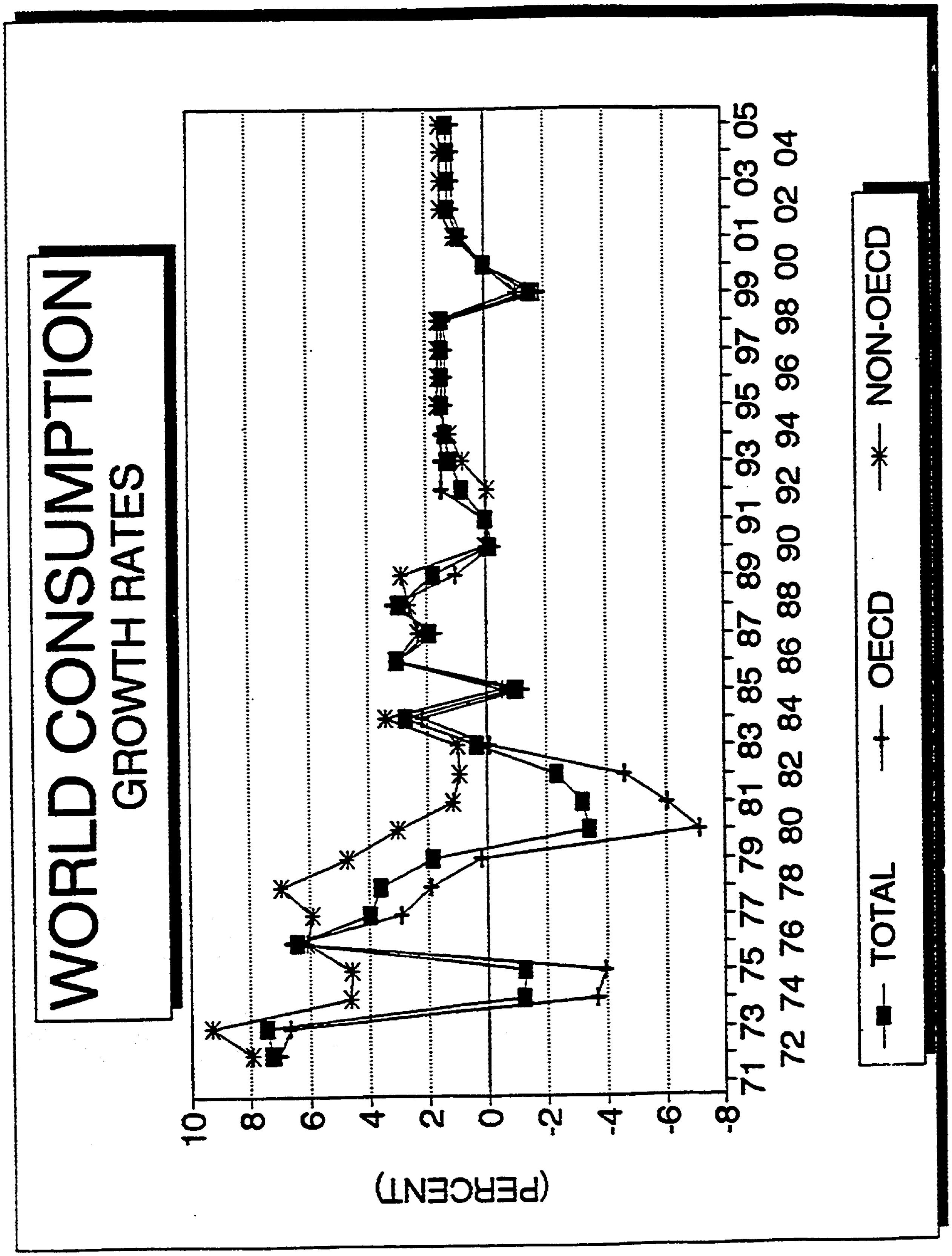

WORLD CONSUMPTION
GROWTH RATES
(PERCENT)
10
8
6
4
2
0
-2
-4
-6
-8
71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 00 01 02 03 04 05
TOTAL
OECD
NON-OECD

Figure A-1

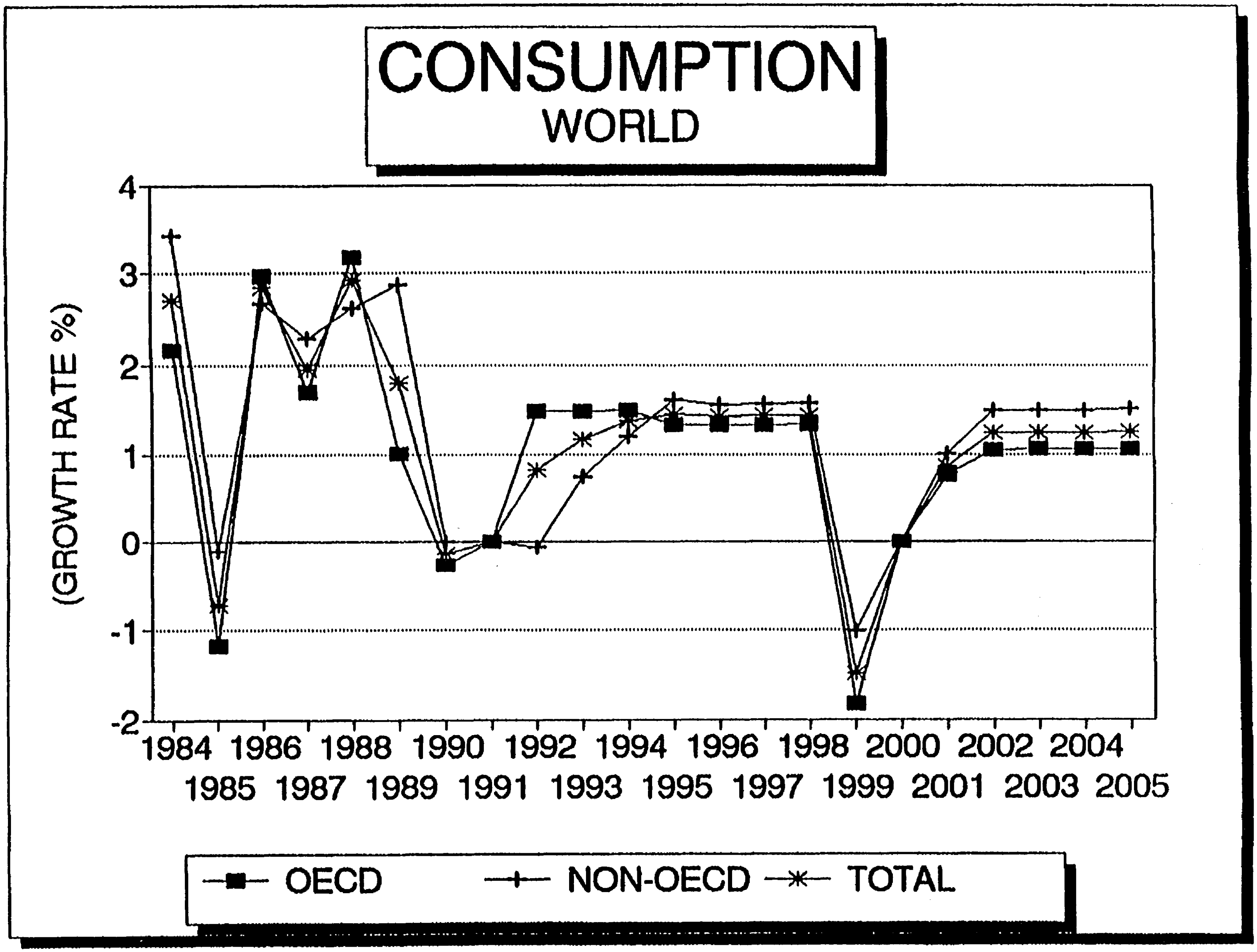

CONSUMPTION
WORLD
(GROWTH RATE %)
4
3
2
1
0
-1
-2
1984 1986 1988 1990 1992 1994 1996 1998 2000 2002 2004
1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
OECD
NON-OECD
TOTAL

Figure A-2

U.S. Petroleum Growth Patterns

North American consumption had been running close to 3% until the current recession hit in 1990. Our forecast assumes that the current recession bottoms at the end of the second quarter of 1992, and that the U.S. economy recovers back to a modest economic growth rate of approximately 3% for GNP, with petroleum demand remaining at a 3:1 ratio to GNP, or a 1% growth rate.

With the constant improvement in the vehicle fleet mpg and modest population and economic growth, we do not foresee a large gasoline growth rate.

North American consumption is forecasted to decline by 2% in 1999 due to the 1998 price spike and the recover to a 0.75% rate (slightly less than before the price spike), for the balance of the forecast period.

European Petroleum Growth Patterns

OECD Europe consumption growth has been closer to the 1% level prior recently as the opening up of Eastern Europe has stimulated the Western Europe economies (especially in Germany). Our forecast calls for growth in OECD Europe to average 1.5% from 1992 through 1994, and then decline slightly to the 1.25% level until after the 1998 price spike occurs.

OECD Europe consumption is expected to decline 2% in 1999 and then recover to the 1% level, which is slightly below the level before the price spike.

Far East Petroleum Growth Patterns

OECD Pacific includes Japan, Australia, and New Zealand (plus U.S. territories such as Samoa); hence, it is only a small part of the Pacific market. The OECD Pacific consumption growth rate has been declining since 1988, and was near the 3% level in 1990. We expect that the Pacific market will continue to grow faster than other markets. Our forecast calls for OECD Pacific growth to average slightly above 2% in 1992 through 1994 and then decline to a more sustainable level of 2.5% from 1995 until after the 1998 price spike.

OECD Pacific demand is forecasted to decline by only 1% in 1999 and then recover back to the 2% level for the balance of the forecast period.

WORLD PETROLEUM CONSUMPTION VOLUMES

With these growth rates total world consumption is forecast to increase from over 65 MMBPD in 1990 by 16.5 MMBPD, to slightly over 82 MMBPD in 2010 (**Table A-2**).

World Refined Products Growth Patterns

Gasoline

Gasoline growth rates have been declining for the total world, OECD, and non-OECD since 1972. Given our economic outlook and the increasing fuel efficiency of newer cars, we expect that this trend will continue into the future.

Our forecast also assumes that non-traditional alternative transportation fuels (i.e., electricity, natural gas, alcohols, and propane) do not make a significant contribution to the gasoline pool during the forecast period. Frankly, the economics, distribution systems, technology, and consumer acceptance just do not exist.

Additionally, the two largest possible future gasoline markets, Russia and China, are lacking not only the U.S. social structure, but also the equivalent of the U.S. interstate highway system and mass transit systems that have fostered our urban sprawl and mass commuting of single workers to the job; therefore, we are projecting world gasoline growth rates moderately over 1% prior to the price spike and slightly below 1% after the price spike.

Jet-kero Fuels

Aviation fuels plus kerosene growth rates have been trending downward slightly, but by a lesser extent than other petroleum products. The relationship between the total world, OECD, and non-OECD growth rates has been slowly reversing in that the OECD growth rate has recently tended to be higher than the non-OECD growth rate. We attribute this to relatively steady non-OECD passenger traffic and low freight traffic, versus expanding OECD passenger and freight traffic as the OECD economies have out performed the non-OECD countries as a group. We expect this trend of higher OECD than non-OECD jet plus kerosene consumption growth rates to continue throughout the forecast period.

Based on our steady but sustainable economic growth scenario, we expect jet plus kerosene underlying growth rates will be close to 2% before the price spike and slightly under 1.75% after the price spike. This is not a dramatic change from the actual historical average growth rate of 2.17% for the 1972 to 1988 period.

Distillates

Based on our forecast for future world economic growth, we are forecasting world distillate growth rates of close to 1.75% before the price spike and close to 1.5% after the price spike. We believe that these growth rates are sustainable and consistent with our outlook of total world economic growth averaging close to 3% during the forecast period.

Residual Fuel Oil

Resid growth rates, except for temporary rebounds recently when prices were low, have been negative since the price shock of 1979.

Our forecast is based on the assumptions that the backing out of resid and replacement by natural gas in dual fired boilers has run its course for the most part. We do not see resid moving back at the expense of natural gas, but we believe that the majority that can be switched out already has been, and it will remain out due to cheaper natural gas prices, (additional electrical generation plants being gas fired both in the OECD, and in the NON-OECD), and due to environmental concerns.

Therefore, we expect resid consumption to grow at the modest rate of close to 0.75% through out the entire forecast period.

Other Products

Other petroleum product consumption is forecasted to be linked to economic growth and grow at a rate close to 1.5% before the price spike in 1998, and close to 1.25% after the price spike.

World Refined Products Consumption Volumes

Based on these consumption growth rates, total world consumption is projected to increase from 1990 to 2005 2.2 MMBPD for gasoline, 1.3 MMBPD for jet plus kerosene, by 2.7 MMBPD for distillate, and by only 0.6 MMBPD for resid and 0.8 MMBPD for other products.

U.S. Refined Products Consumption Volumes

U.S. refined product demand is projected to grow at the same rate as OECD North America. U.S. crude runs are projected to increase from an annual average of 13.4 MMBPD in 1990 to close to 14.1 MMBPD in 2005 and 14.5 in 2010. At the same time, U.S. crude production is projected to decline from 7.3 MMBPD in 1990 to 5.1 MMBPD in 2005, or a drop of 2.2 MMBPD over the forecast period. The 2010 forecast is 4.5 MMBPD, a dramatic 40% drop from 1990 levels. This production profile is based on our estimate of an average U.S. decline rate of less than 2.0% per year.

The balance, of course, is made up by crude imports, which are projected to increase from 5.9 MMBPD in 1990 to 8.8 MMBPD in 2005. At these rates, the politically visible point of imports making up 50% of the U.S. crude supply is projected to occur in 1996.

This trend of declining U.S. production and increasing demand is one of the factors supporting our forecast of increasing WTI versus foreign crude price spreads.

Crude Oil Supply

World crude oil production has quite naturally followed a path similar to that of demand; i.e., peaking in the late 1970s, declining in the early 1980s, and steadily climbing during the past five years (**Figure A-3**). Crude oil production in 1992 is estimated at about 6.6 MMPBD above the low level of 1985, with most of the gain coming from OPEC (**Table A-3**). Our forecast calls for additional production of 3.0 MMBPD by 1995, with OPEC accounting for the greatest share of the increase. Production requirements by the year 2000 will have only increased by about 1.5 MMBPD over 1995 (**Figure A-4**). By that year, OPEC will be required to produce 27.0 MMBPD, which should be quite within its capability, given its 31.0 MMBPD output in 1979.

WORLD CRUDE OIL PRODUCTION (MMBPD)

	1990	1995	2000	2005	2010
OPEC	23.3	26.9	27.0	30.6	31.9
Non-OPEC	36.0	36.5	38.0	38.6	41.9
Total	59.3	63.4	65.0	69.2	73.8
% OPEC	39.3	42.4	·41.5	44.2	43.2

OPEC Crude Oil Supply

In our forecasts, we have taken the middle ground between differing opinions regarding OPEC's future production capability. The production capability of OPEC nations is expected to increase from approximately 27.8 MMBPD in 1990 to 31.8 MMBPD in 1995, and to 36.6 MMBPD by the end of the forecast period (**Table A-4**).

OPEC CRUDE OIL PRODUCTION VERSUS CAPABILITY (MMBPD)

	1990	1995	1997	2000	2005	2010
Production	23.3	26.9	27.8	27.0	30.6	31.9
Capability	27.8	31.8	32.2	32.4	34.8	36.6
OPEC's Percent of Its Capability	83.8	84.6	86.3	83.3	87.9	87.2

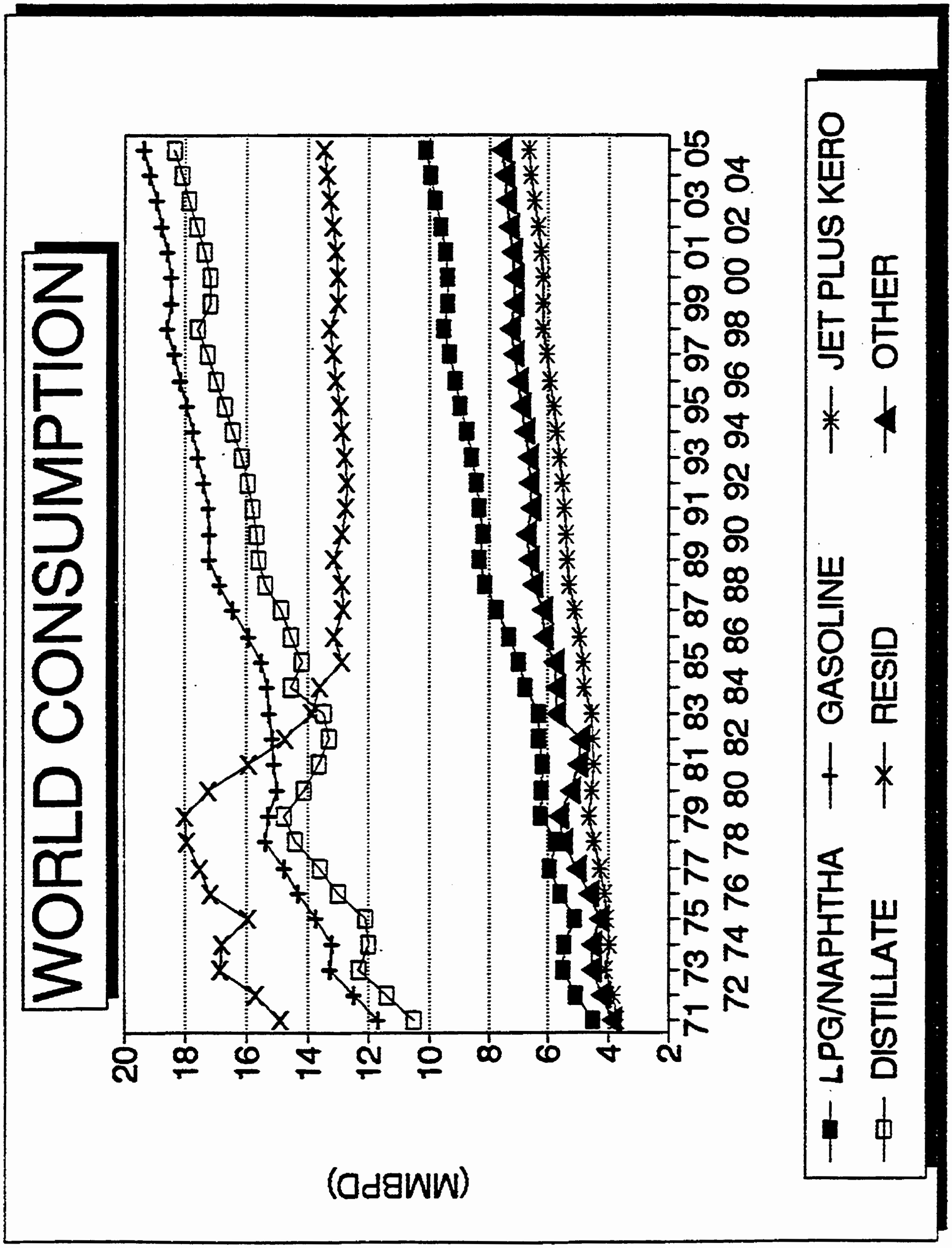

WORLD CONSUMPTION
(MMBPD)
20
18
16
14
12
10
8
6
4
2
71 73 75 77 79 81 83 85 87 89 91 93 95 97 99 01 03 05
72 74 76 78 80 82 84 86 88 90 92 94 96 98 00 02 04
LPG/NAPHTHA
GASOLINE
JET PLUS KERO
DISTILLATE
RESID
OTHER

Figure A-3

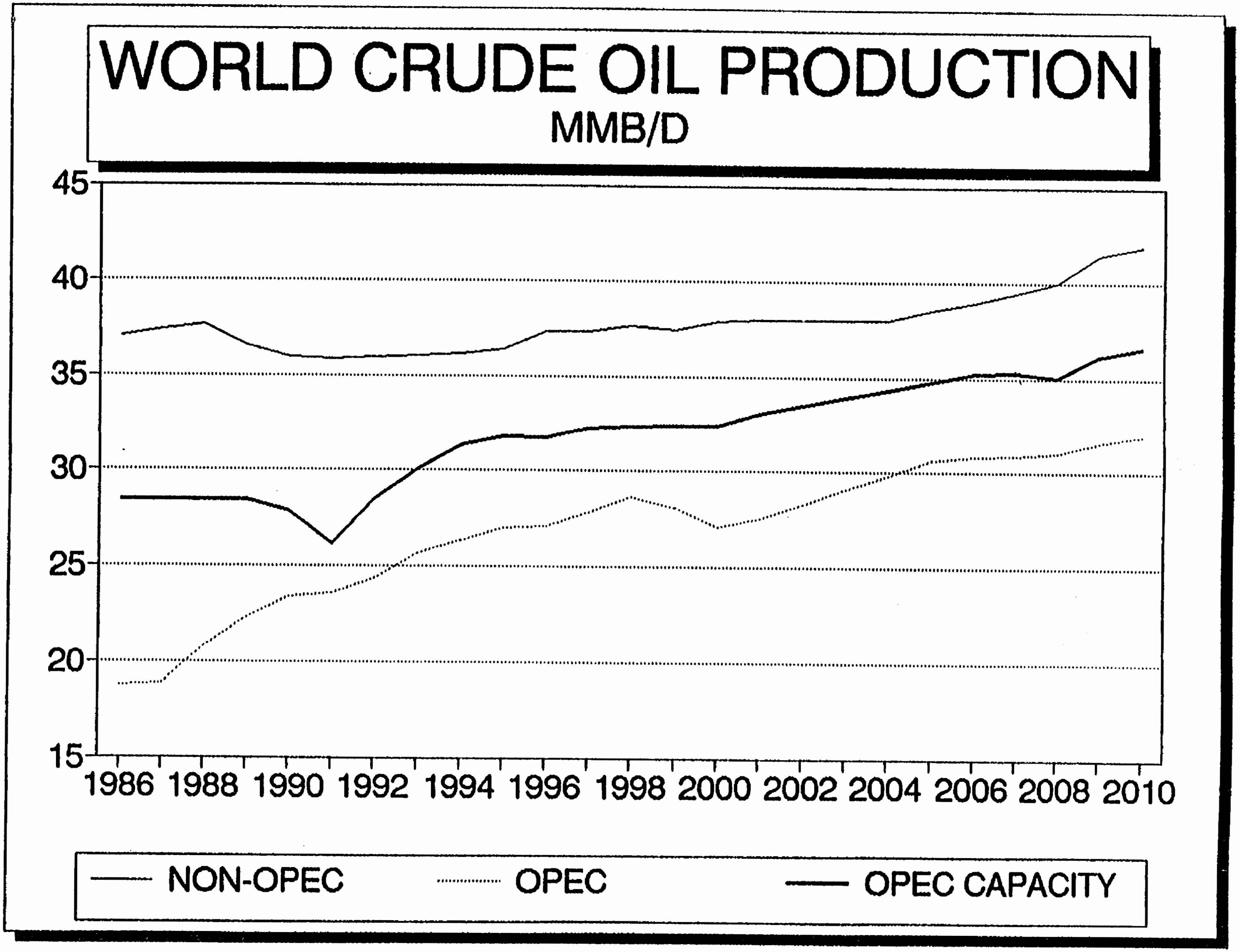

WORLD CRUDE OIL PRODUCTION
MMB/D
45
40
35
30
25
20
15
1986 1988 1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010
NON-OPEC
OPEC
OPEC CAPACITY

Figure A-4

We base our crude oil price forecasts through the mid-1990s on the expectation that OPEC will continue to attempt to control production by member nations to balance supply and demand. However, when OPEC's production begins to closely approach its maximum sustainable capability -- projected to occur in 1998 -- there will be upward pressure on crude oil prices (Figures A-5, A-6).

World Refined Products Market Shares

Looking at the world, the major change is a continuation in the decline of resid's share of the refined product barrel. Gasoline's share declines slightly (0.4)% from 1990 to 2005, jet-plus-kerosene's share increases close to 0.7%, distillate increases slightly over 0.6%, resid's share declines 1.7%, and others' share declines by less than 0.2%.

The change in the composition of the OECD's refined product barrel is very similar to the changes in the world's composition. OECD gasoline declines slightly faster, minus 1.0% versus minus 0.4% for the total world, while OECD jet-plus-kerosene's share of OECD product consumption increases faster, 1.4%.

The net effect of all of these changes is that an increasing percentage of the world's refined product barrel is comprised of light products, while the percentage of heavy products is declining. On a MMBPD basis, from 1990 through 2010 the consumption of the major light products, gasoline and distillate, is continuously growing, while in comparison the consumption of resid, due to its low growth rate, appears to be nearly constant. From 1990 to 2005 the difference in the consumption of gasoline plus distillate versus resid is projected to increase by more than 4.3 MMBPD.

This continuing lightening of the refined product barrel is the underlying factor behind our forecast of: increasing light versus heavy crude spreads, increasing light product versus crude spreads, increasingly negative resid versus crude spreads, and increasing refining margins, all in constant dollar terms over the forecast period.

REFINED PRODUCTS

U.S. Refined Products Demand

Projected U.S. growth rates are assumed to be the same as those for OECD North America (**Figure A-7**). To summarize, total demand is expected to average 1% growth per year prior to the projected price spike in 1998, and 0.75% after the price spike (**Table A-5**).

Major product growth rates (gasoline, jet-kero, distillate, and resid) are expected to be nearly equal to the total product growth rates. The exception to this is during the 1992 to 1995 time period. For the 1992 to 1995 period, "other" demand is depressed, and major product demand is elevated by the projected change over in military jet fuel consumption (180 MBPD) from JP4, which is in the "other" category, to jet-kero, which is in the "major" category.

Individual U.S. product growth rates are projected to be the same as for OECD North America, with some minor differences due to changes in the U.S. market.

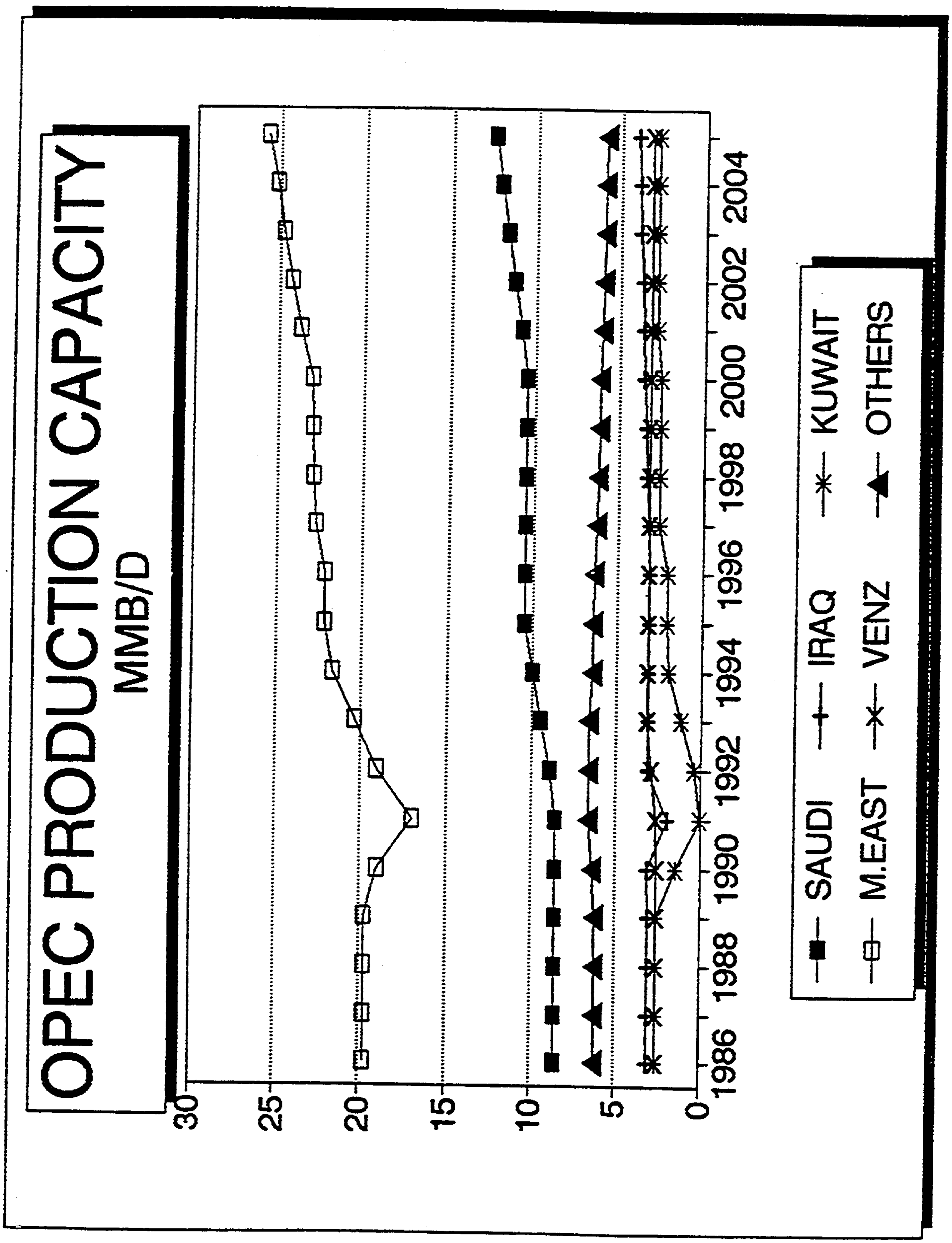

OPEC PRODUCTION CAPACITY
MMB/D
30
25
20
15
10
5
0
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
SAUDI
IRAQ
KUWAIT
M.EAST
VENZ
OTHERS

Figure A-5

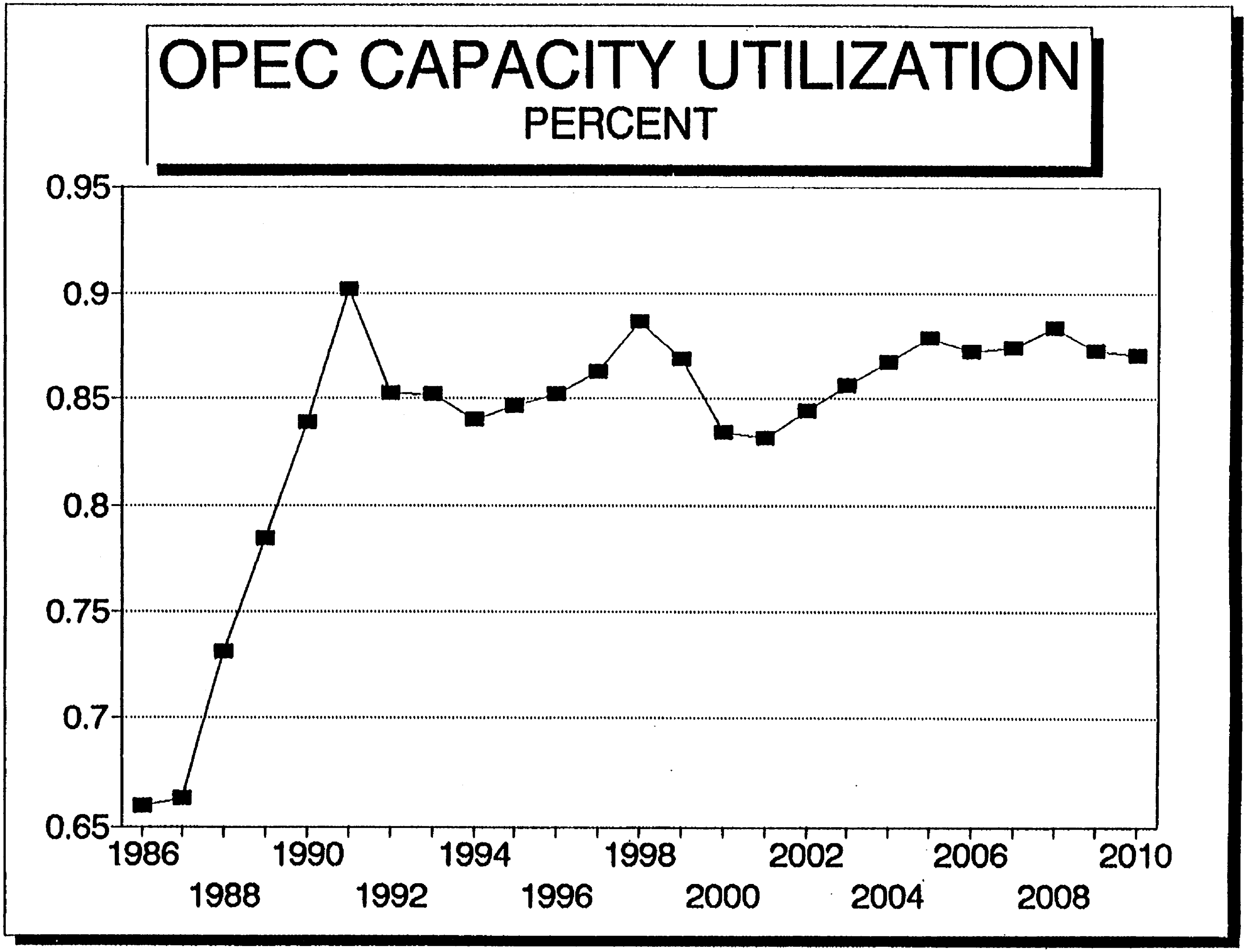

OPEC CAPACITY UTILIZATION
PERCENT
0.95
0.9
0.85
0.8
0.75
0.7
0.65
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010

Figure A-6

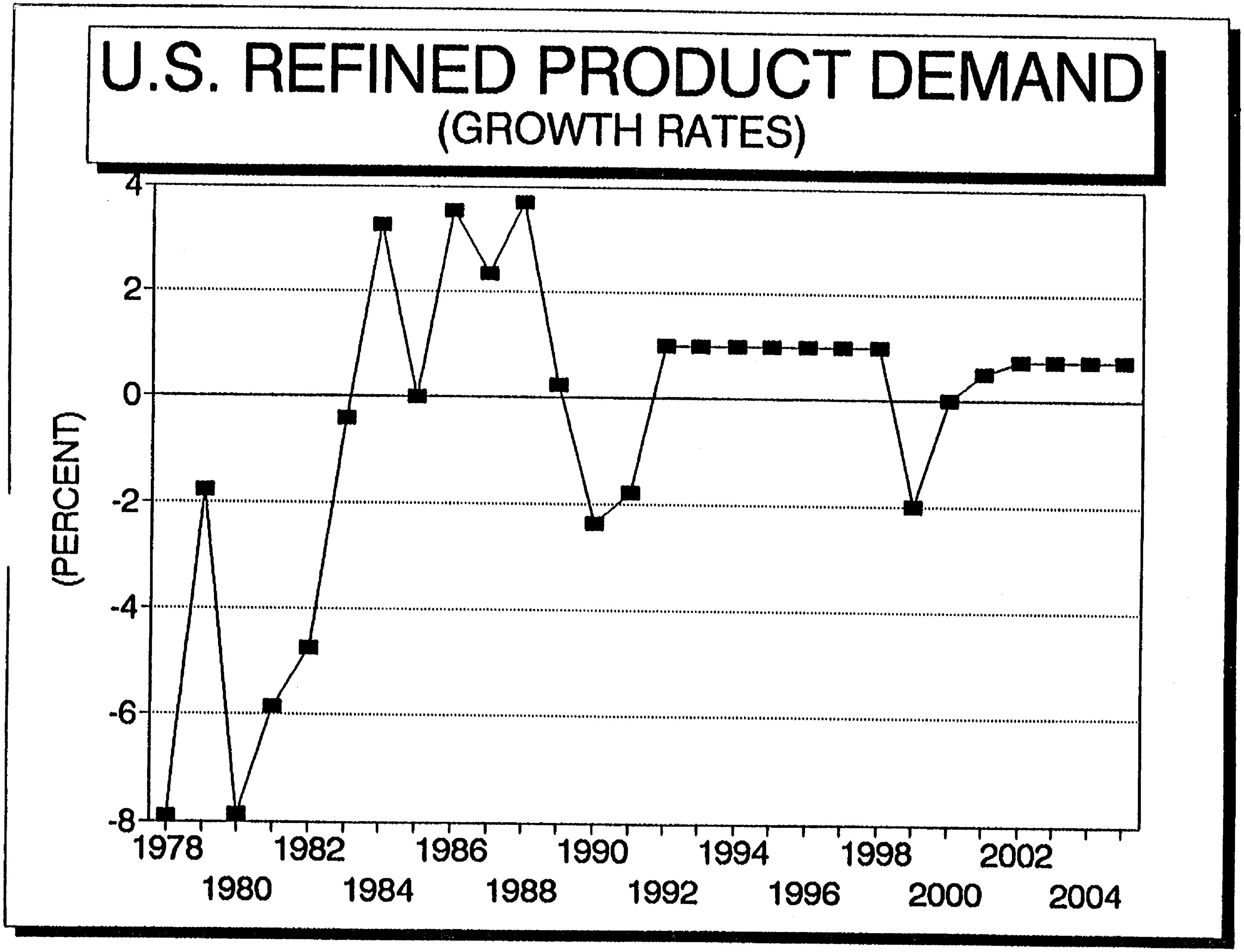

U.S. REFINED PRODUCT DEMAND
(GROWTH RATES)
(PERCENT)
4
2
0
-2
-4
-6
-8
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004

Figure A-7

Gasoline

Gasoline growth is based on an underlying rate of 0.75% prior to the price run up and 0.5% afterwards. With increasing auto fleet mpg ratings, slowing population growth, and moderate economic growth forecast, we do not foresee any major non-gasoline market share growth during this forecast horizon. For alternative fuel cars, our position is that of the consumer: *show me first* (**Table A-6**).

Jet-Kero Fuels

Jet-kero growth rates will continue their upward growth trend; however, through 1995 we are projecting jet-kero growth rates of over 5% through 1995, based on the phasing out of JP4. We project growth rates of slightly over 2% once the phase-out has ended (beyond 1996) until the price spike in 1998. After 1998 the long term jet-kero rate is projected to decline to 1.75% (**Table A-7**).

Distillates

Distillate growth is related to GNP, and is forecast to average 1.5% prior to the spike in prices, and close to 1.2% thereafter (**Table A-8**).

Resid Fuels

With the end of the natural gas surplus not in sight, and crude prices expected to increase in real dollar terms during the forecast period, plus environmental regulations, we do not foresee resid moving back into the boiler fuel market in significant volumes. We expect dual fired boilers to remain on natural gas. By the time that natural gas supplies tighten, resid prices are forecasted to be high enough due to the increase in crude oil prices that natural gas will still be the fuel of choice even with increasing natural gas prices in real dollar terms. Regardless, the volume involved (200-300 MBPD) would be supplied from imports of low sulfur resid and this volume is not large enough to effect the global residual fuel market or change our outlook. Therefore we are forecasting resid growth rates of only 0.25% during the forecast period (**Table A-9**).

Based on these growth rates, U.S. total refined product domestic demand is projected to increase from 16.9 MMPBD in 1990 to 18.7 MMBPD in 2010. Gasoline demand is expected to increase from 7.2 MMBPD to 7.8 MMBPD, jet-kero demand should run up from 1.3 MMBPD to 2.0 MMBPD, distillate is forecasted to increase from 3.0 MMBPD to 3.5 MMBPD, and resid demand should drop from 1990s level of 1.2 MMBPD but increase slightly from 1991's projected demand of 1.1 MMBPD by only 31 MBPD (**Figure A-8**).

With these growth rates the same worldwide phenomena of the lightening of the refined product barrel should also occur in the U.S. market. Gasoline's market share is projected to decline slightly from 1990 to 2005 by 0.7%, jet-kero's share should increase by 2.9%, and distillate should increase by 0.4%. Overall, the percent of light products (gasoline, jet-kero, and distillate) should increase by 2.6%, which will support refining margins and light to heavy crude and product spreads.

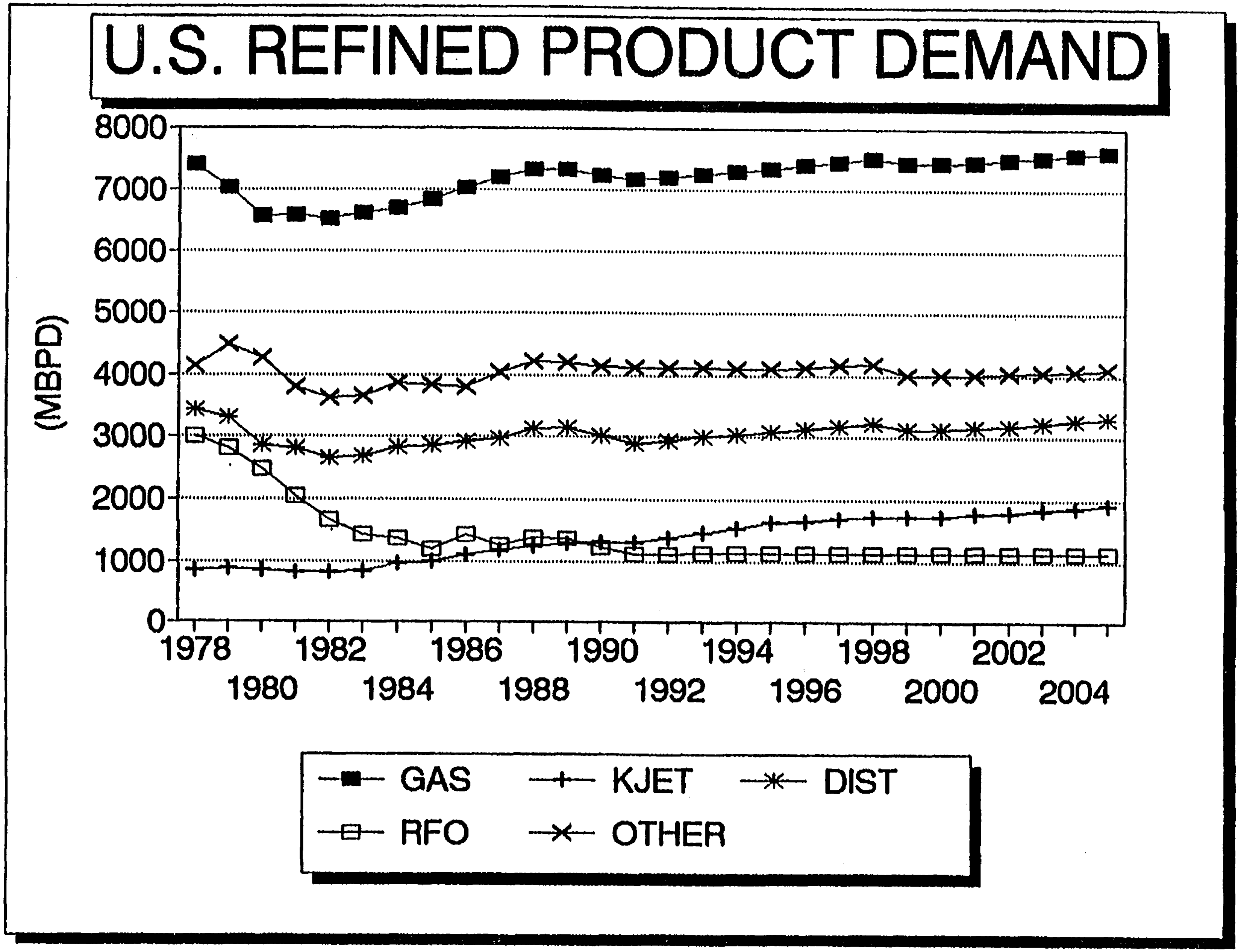

U.S. REFINED PRODUCT DEMAND
(MBPD)
8000
7000
6000
5000
4000
3000
2000
1000
0
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
GAS
KJET
DIST
RFO
OTHER

Figure A-8

Interesting is the implication of these growth rates on the individual light product balances. As is covered in the subsequent sections, the possible tightness in refined products will shift more towards jet-kero. Gasoline and distillate should remain firm, but the overall trends are strongest for supporting jet-kero, and weakening resid-to-crude spreads. How prices eventually equilibrate may be overshadowed by disruptions in the market due to reformulated gasoline and low sulfur diesel. If the end point of gasoline is reduced to meet clean air emissions standards, a lot of material for jet-kero production will be freed up, and will tighten the gasoline supply/demand balance.

U.S. Refinery Operations

U.S. crude runs are forecasted to increase from 13.4 MMBPD in 1990 to 14.1 MMBPD in 2005 and 14.5 MBPD in 2010. We have not assumed any significant change in the U.S. crude distillation capacity in our forecast. Incremental capacity creep is expected to be offset by some refinery closures due to the capital required to upgrade to make reformulated gasoline, low sulfur diesel, and to phase-out JP4 production.

The aggressive small-size refiners are expected to realize that their most profitable future role is to become adjunct distillation capacity for the larger refiners, and to provide them with today's finished products -- which will be tomorrow's intermediate streams and blending components -- and let the larger refiners with their economics of scale and deeper investment pockets make the required capital investments.

Our forecast calls for refinery utilization, defined as crude runs as a percent of operable distillation capacity, to increase slowly over the forecast period, reaching close to 90% of capacity by 2005 (**Figure A-9**). This is one of the factors that underlies our forecast of rising refining margins in constant dollar terms.

U.S. Imports, Exports, and Other Supply

Our projected refined products balance also has several important assumptions concerning product exports, product imports, and other supply. As stated earlier, domestic demand and crude runs are projected to be gradually increasing through the forecast period, with a pull back in both as demand temporarily declines in 1999 and remains flat in 2000, due to the price spike in 1998.

Product imports play a pivotal role due to the nature of a commodity market in which a small surplus or deficit of under 5% of demand is enough to swing prices from their lows to their highs. Or in economic terms, swinging from margins equalling variable cash costs to margins providing a level of capital recovery that provides enough incentive to expand capacity.

Based on our analysis of the Clean Air Act and the population of the non-attainment cities, and of supply logistics, we believe that the minimum percent of the U.S. gasoline pool that is comprised of reformulated gasoline in 1995, if no cities "opt in," is 35% of the total pool.

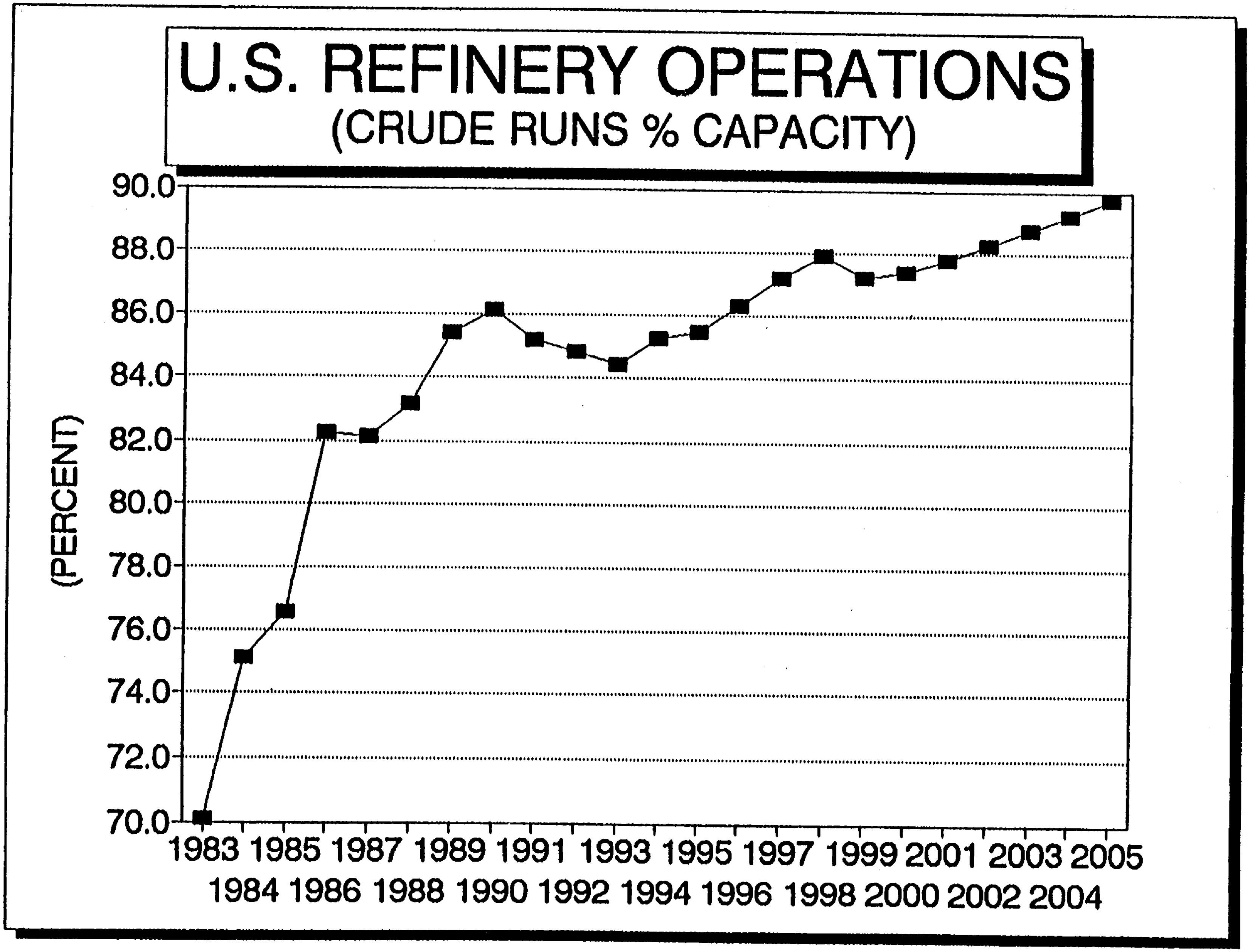

U.S. REFINERY OPERATIONS
(CRUDE RUNS % CAPACITY)
(PERCENT)
90.0
88.0
86.0
84.0
82.0
80.0
78.0
76.0
74.0
72.0
70.0
1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
1984 1986 1988 1990 1992 1994 1996 1998 2000 2002 2004

Figure A-9

Our forecast is based on the assumption that U.S. gasoline imports, which primarily come into the New York harbor area, will meet the Clean Air Act requirements. Since the majority of the exporters of gasoline to the United States do so based on economic incentives, or foreign exchange needs, we do not believe that they will walk away from the U.S. market. Instead, we believe that they will gear up to produce reformulated gasoline for export to capture what they believe will be a high priced commodity. However, this switch to reformulated gasoline, along with growing specification changes in non-U.S. markets and rising non-U.S. demand, is expected to keep gasoline imports flat at the 300 MBPD level through most of the forecast period.

With finished gasoline imports projected to be flat, the balance of the MTBE and other oxygenate requirement must be met by U.S. production and by imports. While this volume is small on the scale of the total U.S. refined product balance, it is important in the U.S. gasoline balance because it represents an additional source of gasoline without running any more crude.

With domestic demand growing, refinery utilization increasing, new grassroots refineries being built overseas, and the United States' being a net refined product importer, we do not expect refined petroleum products exports to increase during the forecast period. In fact, we expect total product exports to decline slightly as exports of major products decline as U.S. refining capacity approaches full utilization, and exports of other products level off. Gasoline exports are forecast to remain constant at 50 MBPD, jet-kero exports should be flat at 25 MBPD, and distillate exports should decline to 50 MBPD as domestic demand increases. Resid exports are projected to remain flat at 225 MBPD, based on the assumption that additional coking capacity will be built or present cokers expanded to offset the otherwise expected increase in production that would occur with the crude slate getting heavier, and crude runs increasing.

Product imports are forecast to move up and down with the changes in U.S. demand, as they are the incremental balancing item in the refined product supply/demand balance, especially as the United States nears 90% of capacity near the end of the forecast period. Product imports are currently depressed, as was domestic demand in 1991. Imports should recover in 1992 and 1993 as the economy rebounds, and demand moves back up to an annual projected growth rate of 0.75%.

Both categories, major products and other products, are expected to follow this profile. With the switch to reformulated gasoline, gasoline imports are projected to remain constant at 300 MBPD as stated previously. Jet-kero imports are expected to increase steadily as demand grows throughout the forecast period. Distillate imports should track the overall distillate demand pattern, and resid imports are projected to remain essentially flat similar to domestic demand.

On a percent of domestic demand basis, product imports should rebound in the next several years to slightly over 12%, decline as demand falls in 1999, and rise back above the 12% level by the end of the forecast period. This cyclic need for imports to balance the market implies that there will also be a similar cycle in the support for product-to-crude spreads and refining margins, as these imports will need higher prices than at their originations in order for the economic incentives to be present.

Gasoline

As discussed earlier, U.S. domestic gasoline demand is expected to be undergoing moderate growth (with the exception of the reaction to the 1998 price spike) throughout the forecast period (**Figure A-10**), (**Table A-6**). With imports projected to be flat, this translates to an increasing requirement for U.S. production. Gasoline production is projected to increase from close to 7 MMBPD in 1990 to slightly under 7.4 MMBPD in 2005, an increase of 400 MBPD, and to reach the 7.5 MMBPD range in 2010.

These numbers translate to an increasing production of gasoline from crude or yield from the 1990s level of 52%; this rate is achievable, however, due to the introduction of an additional 185 MBPD of MTBE into the gasoline pool. If this incremental volume of MTBE were backed out of the gasoline yield calculation, then the yield of gasoline at the 1991 level of MTBE usage would actually decline from close to 52% down to 51% in 2001 and then level off at that point. This adjusted yield pattern is based on stage two vapor pressure reductions, some volume loss due to processing changes to meet reformulation specifications other that oxygen content, declining yields as production capacities are pressed, a slightly heaver U.S. crude slate, and an increase in the percent of unleaded premium and unleaded midgrade in the gasoline pool.

The U.S. gasoline supply/demand balance is expected to continue to set the level of U.S. crude runs and the overall level of refining margins. Although gasoline imports are projected on an annual basis to be flat, they will still have an effect on future gasoline-to-crude spreads, but to a possibly lesser extent than in the recent past.

With all of the possible disruptions due to the changing gasoline specifications, the underlying fundamentals of increasing demand and additional incremental processing are the support for our expectation of a gradually tightening gasoline market which is expected to support higher gasoline-to-crude spreads in constant dollar terms through out the forecast period.

One final comment on reformulated gasoline specifications: the recent report of the auto/oil industry study that reducing gasoline's end point could be beneficial in terms of air quality, could have a significant effect on our forecast. If gasoline's end point were to be reduced, it would have the effect of shifting barrels out of the gasoline pool and into the jet-kero pool. This situation would result in an increase in jet-kero yields, and a decrease in gasoline yields, thus making the gasoline supply/demand balance tighter and the jet-kero supply/demand balance longer versus its current slightly short position.

In 1990, we saw the drop in premium market share, while midgrade market share remained constant when pump prices jumped through the roof with the invasion of Kuwait (**Figure A-11**). As data comes in for 1991 actual and the premium market share is recovering but has not gone back to the 22% level of before the war despite a retreat in prices, our conclusion that the last increment of premium demand was based on a "buy the best" rather than "buy what is required" reasoning appears to be correct.

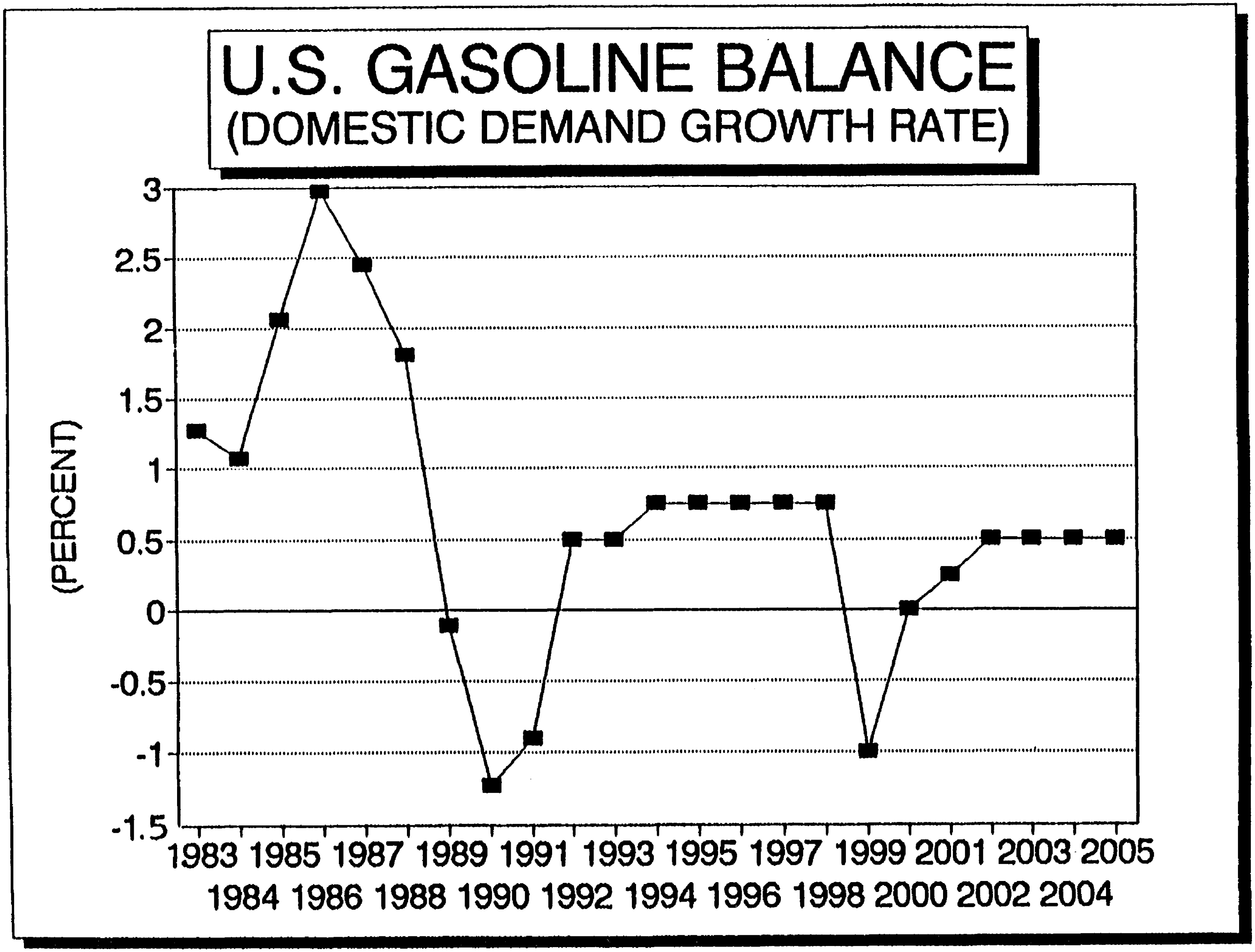

U.S. GASOLINE BALANCE
(DOMESTIC DEMAND GROWTH RATE)
(PERCENT)
3
2.5
2
1.5
1
0.5
0
-0.5
-1
-1.5
1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
1984 1986 1988 1990 1992 1994 1996 1998 2000 2002 2004

Figure A-10

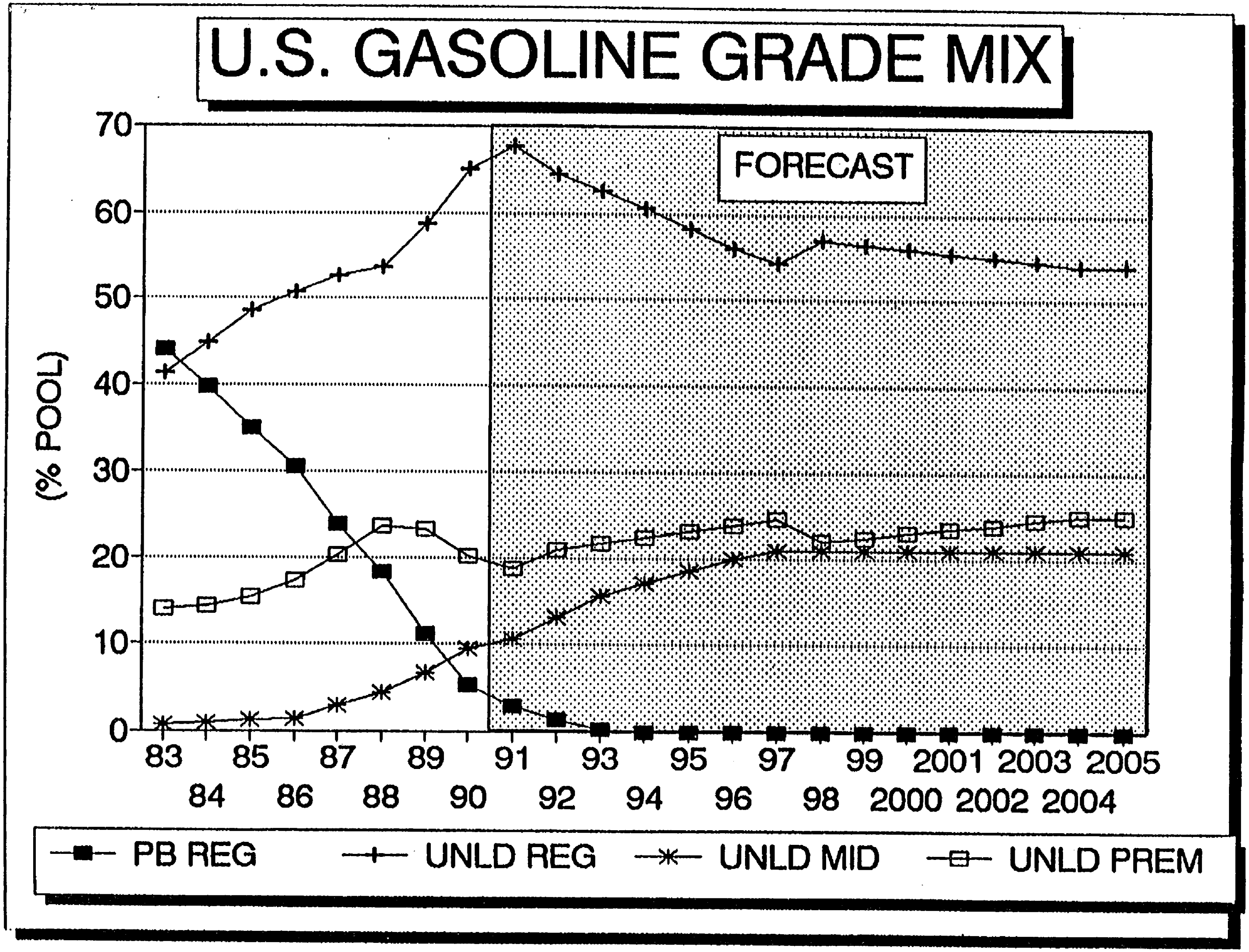

U.S. GASOLINE GRADE MIX
FORECAST
(% POOL)
70
60
50
40
30
20
10
0
83
84
85
86
87
88
89
90
91
92
93
94
95
96
97
98
99
2000
2001
2002
2003
2004
2005
PB REG
UNLD REG
UNLD MID
UNLD PREM

Figure A-11

Based of this and historical trends, our forecast calls for the premium unleaded market share to gradually rise over the forecast period, reaching almost 25% in 1997, declining as prices jump up in 1998 back to the 22% level, and then slowly increase and remain at the 25% level during the end of the forecast period. Unleaded midgrade market share is forecasted to increase to 21% by 1997 and then remain at that level for the rest of the forecast period. This grade mix profile will result in an increasing average pool octane, which, along with the underlying growth in demand will result in an increasing total octane barrel requirement.

Some of this additional octane will be provided by the increase in MTBE supplies; however, due to the time limits of the Clean Air Act, MTBE is going to be a rather expensive octane source, as its price is likely to be more a function of cash manufacturing costs than octane blending value. This projections supports our forecast of slightly increasing gasoline grade differentials over the forecast period.

JP4 (Naphtha-Jet)

The U.S. JP4 market is a result almost exclusively of U.S. military purchases. This product falls into the "other" refined product category. Recently the military has been consistently purchasing close to 200 MBPD of JP4. This volume dropped to 180 MBPD in 1990, and is projected to average 180 MBPD in 1992.

Due to safety concerns and the fact that since JP4 is a specialty product it carries a price premium, the military has been considering a phase-out of JP4 purchases and switching over to jet-kero which is less volatile and cheaper.

Based on conversations with various sources, our estimate is that the phase out will begin in 1992, with no JP4 being purchased by 1995. Therefore our forecast has military demand constant at 180 MBPD, and switching from JP4 to jet-kero by 45 MBPD each year from 1992 to 1995.

Because the majority of the JP4 stream falls in the gasoline boiling range, this phase out will increase the jet-kero yields slightly, but the volumes are so small that its net effect will be minor. The major effect is that the jet-kero demand growth rate will be above our base growth rate assumption of slightly over 2% until the phase-out is completed.

Jet-Kero Fuels

The U.S. jet-kero growth rate has been trending downward since 1984. Given moderate economic growth, the fact that air fares are low and airlines are losing money, and the government can only "deregulate" an industry one time, we expect the trend of declining growth rates to continue throughout the forecast period. As previously discussed, U.S. jet-kero growth will be above our estimate of its long term growth potential due to the phase-out of JP4 from 1992 to 1995.

Regardless of the timing of the JP4 phase out, we are predicting a tightening of the U.S. jet-kero supply/demand balance over the forecast period. With increasing demand and increasing imports, jet-kero yield on crude will still need to increase substantially in order for production plus imports to meet demand.

Our forecast calls for the jet-kero yield to increase from 9.6% of crude runs in 1990 to 12.5% in 2005. The basis for this strong performance is the industry's fourth quarter 1990 actual performance of producing jet-kero at a yield of 11% of crude runs.

Jet-kero imports are forecasted to increase throughout the forecast period. An increase in imports is consistent with a lower NON-OECD jet-plus-kerosene growth rate than the OECD growth rate. If our import forecast is too low, there will still be a strong jet-kero market, as a greater economic incentive will be required to provide higher imports (Table A-7).

Based on this tight jet-kero balance, we are forecasting jet-kero to distillate spreads to increase in constant dollar terms over the forecast period.

Distillates

U.S. distillate demand is projected to grow based on its linkage to GNP during the forecast period. With distillate demand growing faster than the total refined products growth rate, and faster than gasoline, which is expected to continue to set U.S. crude runs, we are forecasting an increase in distillate imports with a fluctuating, but essentially flat, distillate yield profile to balance the distillate market.

Due to the increase in jet-kero yields to meet demand, we expect the majority of the incremental distillate supply to come from imports. Our forecast assumes that the combined jet-kero plus distillate yield on crude will increase from its current level of slightly under 31% to 33% by 1995, and then remain fairly flat increasing slightly to just over 33.5% in 2005 and 2010.

With domestic production getting tighter, we see imports returning back to the 350 MBPD level by 1998, declining slightly with the price spike and then increasing again in the first decade of the 2000s. This level of imports represents an increasing dependence on imports with the percent of domestic demand being comprised of imports rising to 12% by the end of the forecast period (Table A-8).

With distillate or gasoil the major product for the rest of the world, this balance supports rising distillate to crude prices in constant dollar terms.

Residual Fuel Oil

U.S. resid demand is projected to experience a low growth rate throughout the forecast period, resulting in resid demand remaining essentially flat. With flat demand and increasing crude runs, either exports will have to increase or resid's yield on crude will have to decrease.

With a slowly growing export market and a tightening light product market, we believe that U.S. coking or other resid conversion capacity will be expanded enough over the forecast period in order to keep resid production and exports essentially flat. This means that resid exports as a percent of production will increase only slightly, imports as a percent of demand will remain constant, and the resid yield on crude will decline from 7.1% in 1990 to 6.8% in 2005 and 2010.

With resid becoming more of a byproduct and less of a co-product, we see little fundamental support for anything but increasingly negative resid to crude spreads in constant dollar terms once the resid market reaches a price equilibrium (**Table A-17**).

U.S. Refining Margin Implications

The major implication of the U.S. total and individual refined product balances is a fundamental support for increasing refining margins. With positive but modest light product growth rates, and stagnant resid demand, the U.S. refined product barrel is getting lighter just as is happening in the rest of the world (**Figure A-12**). In addition, with refining capacity utilization already high and increasing, incremental demand will have to be met by product imports which traditionally have a higher cost than buying crude and refining it.

While on a yield-from-crude basis the pressure on gasoline is not apparent, the changing specifications and increasing octane barrel requirement will support the gasoline market. At the same time, the combined middle distillate market (jet-kero and distillate) is projected to be tightening which will support middle distillate prices. And finally, a permanently weak resid market, due to the low yield on crude, will not be enough to outweigh the positive light product pressures on refining margins.

WORLD PETROLEUM SUPPLY

Based on our demand balances, the total world petroleum demand is forecast to increase from 65.5 MMBPD in 1990 to 77.0 MMBPD in 2005, and 82.2 MMBPD in 2010. This demand is forecasted to be met by 36.0 MMBPD of non-OPEC crude production in 1990 and 38.6 MMBPD of non-OPEC crude production in 2005, or an increase of 2.6 MMBPD. This leaves the market-balancing call on OPEC crude of 23.3 MMBPD in 1990, increasing to 30.6 MMBPD in 2005, and 31.9 MMBPD in 2010 (**Table A-10**).

OPEC Crude Oil Supply

Although we forecast a constantly increasing call on OPEC crude oil production throughout the forecast period (except for a minor pull back after the 1998 price spike), OPEC's next major problem will be accommodating increases in supplies from Iraq and Kuwait. Their production increases in both capacity and desires are forecast to out pace the world's call on OPEC crude.

We believe that the current situation of OPEC's being divided into two groups (one consisting of the major producers (Saudi Arabia, Iran, Iraq, Kuwait, UAE, and Venezuela) that allow their production to swing slightly in order to balance the market, and the minor players comprising the rest of OPEC (Ecuador, Gabon, Algeria, Libya, Indonesia, Nigeria, and Qatar) that do not have the large future production capacity potential and generally tend to produce as much as they can) will continue throughout the forecast period.

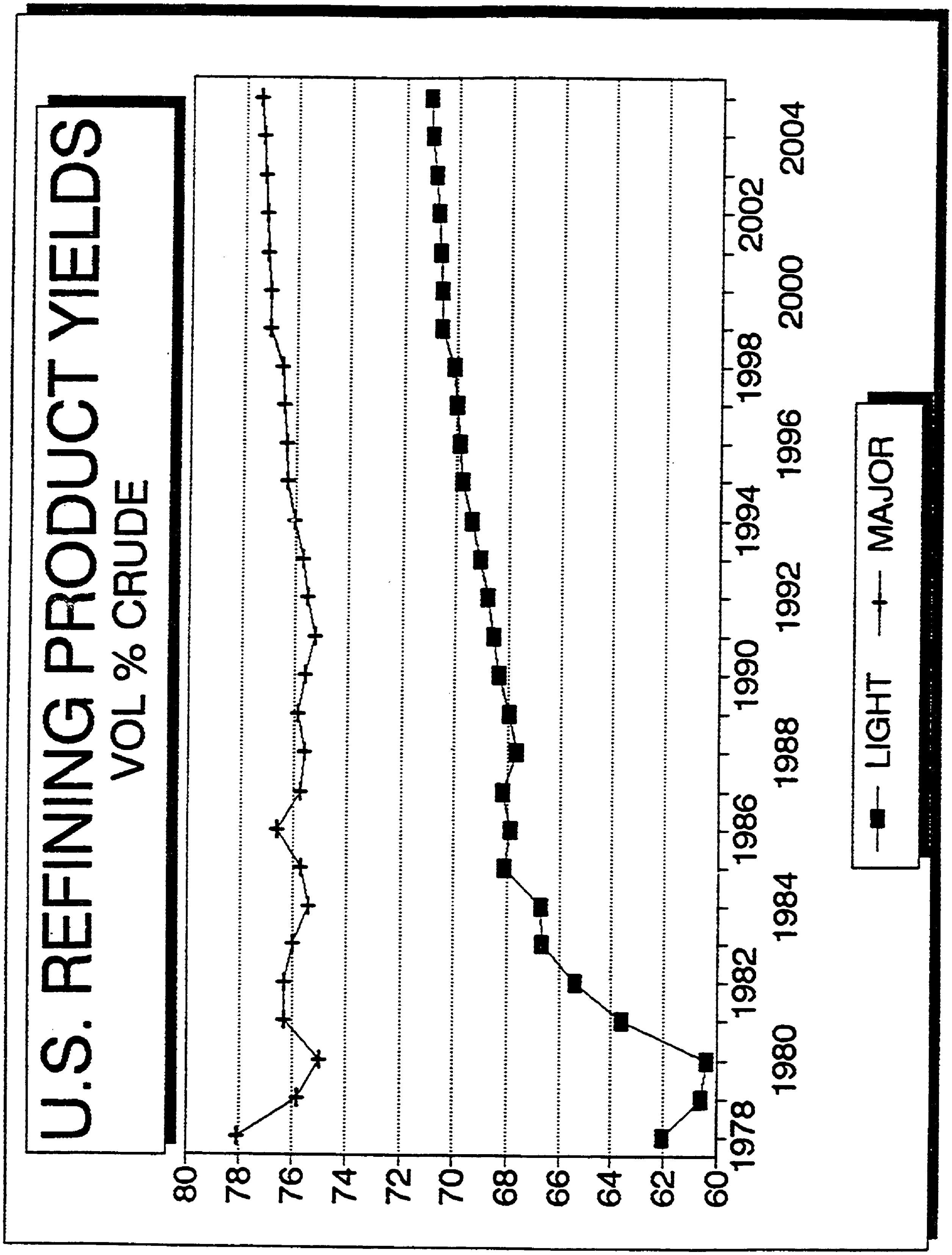

U.S. REFINING PRODUCT YIELDS
VOL % CRUDE
80
78
76
74
72
70
68
66
64
62
60
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
LIGHT
MAJOR

Figure A-12

With this underlying assumption for OPEC, we first need to determine the production of the "minor" producers in order to determine whether the remaining market share of the major producers is large enough to accommodate their individual production goals with a minimum of discipline. If this is indeed the case, then we have a sound basis for a price forecast of crude prices increasing slightly in constant dollars, which is the stated goal of the Saudis.

Minor Producers

The minor producers (except for Qatar) are all outside of the Middle East geographical grouping of OPEC. While OPEC production has been increasing since 1986, the non-Middle East portion has been nearly flat. Due to the future capacity estimates of the minor producers (except for Qatar, all of the minor producers' capacities are forecasted to decline or peak over the forecast period), this trend is expected to continue in the future. The major capacity increases will be the countries with the largest reserves, which is the Middle East OPEC countries (**Table A-3**).

Minor-member OPEC production is forecasted to remain between the 6.4 MMBPD and the 6.6 MMBPD levels throughout the forecast period. This assumes that Ecuador, Gabon, Algeria, and Libya continue to produce as much as they can (at or near 100% capacity utilization) as they have in the past. Indonesia is projected to continue to consistently produce at 50 MBPD below their reported capacity (which appears overstated). Qatar is expected to increase its production both in absolute barrel terms and as a percent of capacity utilization.

Nigeria is expected to help support prices during 1992 through 1994 as Iraq's and Kuwait's production comes back on the market. This cooperation is minor though, and we have forecasted Nigeria continuing to produce at 1.9 MMBPD during this period. This represents a 86% utilization rate given our estimates of Nigerian capacity peaking in 1993 to 1995 at 2.2 MMBPD.

Major Producers

OPEC's ability to support crude prices will be a function of the individual countries' production capacities and their volume and price desires. Saudi capacity is forecasted to increase from its current level of 8.6 MMBPD in two stages to 12.5 MMBPD by the end of the forecast period. The first expansion to 10.5 MMBPD is expected to occur from 1992 to 1994. The second expansion is expected to occur from 2001 to 2010.

Iran's capacity is projected to maintain its current level of 3.5 MMBPD in 1992 throughout the forecast period.

The UAE's capacity is expected to increase by 75 MBPD in 1992, and remain at the 2.5 MMBPD level throughout the forecast period.

Iraq's production capacity is expected to be limited by its shipping or exporting capacity in the near term. This obviously is a function of the UNITED NATIONS sanctions, Saudi wishes concerning use of the crude export lines to the Red Sea, and construction timing estimates (lifting of UNITED NATIONS. sanctions on trade required) for rebuilding the pumps to get southern crude into the Turkey lines, rebuilding the pumps to get crude into the trans-Arabian lines, and rebuilding the Fao export terminal.

Assuming that the Saudis do not let Iraq use the trans-Arabian lines, Iraq could have produced close to 2 MMBPD in 1991 (1.6 MMBPD exported via the Turkey line, and current 350 MBPD production for internal consumption and exports to Jordan). If the sanctions were lifted shortly, then either by rebuilding Fao or if the Saudis let Iraq use the lines to the Red Sea, then Iraq could produce and export slightly above its pre war capacity of 3.1 MMBPD starting in 1992. Due to its reserves, Iraq is expected to be able to raise its capacity starting in about five years from now, from 3.1 MMBPD in 1996 to 4.0 MMBPD by 2005 and beyond.

Due to the oil well fires and extensive damage to the crude gathering system and wellheads, Kuwait's capacity rise is projected to be slower than Iraq's. Realistically, we expect Kuwait capacity to remain low in 1992, and then rebound quickly in 1993 and 1994 leveling off at 2 MMBPD (below its pre war level of 2.5 MMBPD) until 1997 when capacity is raised back to the 2.5 MMBPD level. In 2001, we expect Kuwaiti output to expand slightly to 2.7 MMBPD but remain at that level for the balance of the forecast period.

We believe that these capacities are realistically achievable, versus the somewhat inflated numbers that are constantly reported by the news services.

With this production capacity, the problem for OPEC is to devise an acceptable production level from 1991 through 1994 that will support crude prices. After 1994, with the Major OPEC producers projected to be fairly constant, world demand is projected to out-pace OPEC capacity additions, making it easier for the major producers to reach a production control agreement.

In the near term (until the 1998 price spike), we expect Iraq to produce as much as it can. For this forecast, we have assumed that the UNITED NATIONS. sanctions are lifted in the middle of 1992. As of this moment, Iraqi production should jump by 800 MBPD in the first half as the Kirkuk field production is exported via the Turkey line. In the second half, after the pumps are replaced, the Turkey line should be running at capacity of 1.6 MMBPD, bringing Iraq's total production to 1950 MBPD. Thus, Iraq should be able to average 1.36 MBPD of crude production in 1992.

In 1993, one year after the lifting of the UNITED NATIONS. sanctions, we expect work to have progressed enough to allow exports to begin at Fao. The rebuilding of Fao (or it could be the reopening of the Saudi lines to the Red Sea), will allow Iraq's production to rise to 2393 MBPD.

In 1995, as work is completed at Fao, Iraq's production is expected to raise to 3.1 MMBPD and remain there through 1996.

From 1997 through 2005, Iraq's production is expected to increase along with world demand. To help support prices, we see them holding production slightly below capacity starting in 1999 when demand drops, but keeping production constant in absolute barrel terms and then raising production when demand rebounds.

Kuwait is expected to produce at 100% of capacity until 1997, when their capacity jumps from 2 MMBPD to 2.5 MMBPD. At this point, Kuwait is expected to increase production only in line with world demand in order to support prices.

Thus, our balance calls for Kuwaiti production to increase rapidly after a slow start. Kuwaiti production is estimated to average only 137 MBPD in 1991, 530 MBPD in 1992, jump to 1.3 MMBPD in 1993, increase further to 1.9 MMBPD in 1994 and 2.0 MMBPD in 1995 and 1996.

With Iraq and Kuwait maximizing production, this leaves the job of balancing the market up to Saudi Arabia, Iran, the UAE, and Venezuela. All four need to make some production cuts from their still unofficial 1991 levels of 8.1 MMBPD, 3.3 MMBPD, 2.4 MMBPD, and 2.3 MMBPD, respectively, in order to make room for increasing Iraqi and Kuwaiti production through 1994.

We have assumed that there is some limited degree of cooperation and sharing of production cutbacks among these producers. Due to the heavy nature of its crude (translating into limited demand), we expect Venezuela will be willing to reduce production down to the 2.25 MMBPD level in 1992.

Saudi Arabia

This individual production profile leaves the Saudis with a market balancing demand for their crude of 8.1 MMBPD in 1991, slightly over 7.8 MMBPD in 1992, 7.2 MMBPD in 1993, and reaches a low point of close to (but above) 7.2 MMBPD in 1994.

We believe that this production profile will be palatable to the Saudis. It keeps them above their pre-war level of production, and represents a reduction to only 26% of total OPEC production, which is at or above 1986 to 1989 levels of this measure. Saudi production on a capacity utilization basis would only decline to 65% in 1994, which is above recent per-war levels, even though they are expected to have added additional capacity by then.

Price Implications

OPEC capacity utilization is projected to be on an overall upward trend over the forecast period and reach a minimum of only slightly over 81% in 1994, when all of Iraq's and Kuwait's production comes back onstream. With these high capacity utilization rates, crude prices are forecasted to increase from their low 1991 levels, due to current crude stock overhang, and then remain fairly constant in real dollar terms through 1995. Starting in 1996 and continuing through 1998, crude prices should gradually increase in real dollar terms as OPEC's capacity utilization rate climbs over the 85% level.

In 1998, with OPEC capacity utilization over 88 percent, we expect another of the politically motivated price spikes to occur as only the Saudis will have significant levels (in themselves capable of lowering prices) of spare production capacity. After the price spike occurs in 1998, demand is forecasted to decline as it has with the previous price spikes and OPEC capacity utilization is projected to drop back towards 83% with prices forecasted to be depressed in 1999 and then recover in 2000. From 2001 to 2010 with demand and OPEC's utilization rate increasing, prices should have fundamental support to increase gradually in real dollar terms.

We estimate that OPEC provided more than half of the world's crude oil in 1980, but its market share decreased to 31.4% in 1985. **OPEC's market share is estimated at 39.3% in 1990, and is projected to be 41.6% by the end of the decade. Thus, OPEC is well on its way to reclaiming the dominant position it held during the 1970s when its market share exceeded 60%.**

During the early 1980s, the productive capacity of OPEC fell along with its actual production. Several OPEC nations have announced intentions to increase their production capacity. Some announcements, particularly by Saudi Arabia, have been received at face value. Plans by other countries such as Iraq, Iran, and Venezuela have met with some skepticism. Most skeptics question whether these nations have the financial ability to undertake the enormous investments that will be needed.

Non-OPEC Crude Oil Supply

Thus, the prevailing present trends of nearly flat non-OPEC crude production, OPEC remaining the residual supplier, and OPEC's share of the world's crude market increasing are projected to continue through out the forecast period **(Figure A-13)**, **(Table A-3)**.

The slightly increasing non-OPEC production profile is based upon declining production in North America, Mexico's production increasing modestly, declining U.K. production, Russian production continuing to decline until it bottoms in 1995, and nearly flat production in China. Other non-OPEC countries' productions are projected to increase to offset the declines in the mature production countries.

The slightly increasing non-OPEC production profile is based upon declining production in North America, Mexico's production increasing modestly, declining U.K. production, Russian production continuing to decline until it bottoms in 1995, and nearly flat production in China. Other non-OPEC countries' productions are projected to increase to offset the declines in the mature production countries.

Specifically, our forecast is based on a decline rate slightly under 2.5% per year for the U.S. through the forecast period. Thus, U.S. production is projected to decline from 7.3 MMBPD in 1990 to 5.1 MMBPD in the year 2005, and 4.5 MMBPD in 2010.

Mexican crude oil production is forecasted to expand from 2.5 MMBPD in 1990 to 2.8 MMBPD in 2005, and 2.9 MMBPD in 2010. This projection is based on an increase in production in 1991 that we are already seeing, followed by no production gains until 1994 when the result of the current expansion in the Mexican drilling and investment program begins to pay off. At this point, Mexican production is projected to increase by 1% per year for three years and then level off at a long term sustainable growth rate of 0.5% per year.

Canadian production is projected to increase in 1994 based on available production figures, decline in 1996, remain constant through 1998, and then assume a long term decline rate of 1% per year. This outlook translates into Canadian production remaining essentially flat near the 1.5 MMBPD level through out the forecast period.

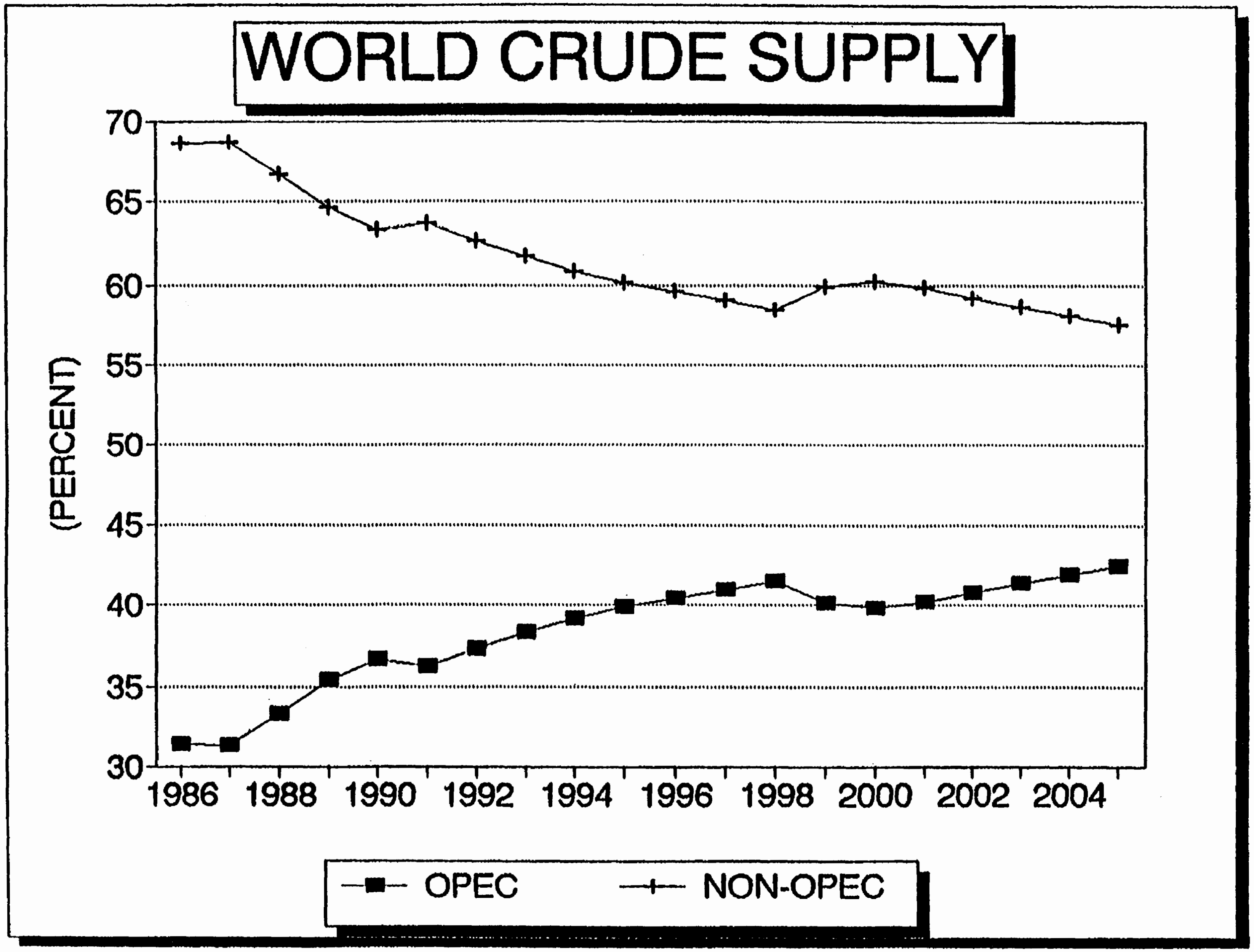

WORLD CRUDE SUPPLY
(PERCENT)
70
65
60
55
50
45
40
35
30
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
OPEC
NON-OPEC

Figure A-13

Russian production peaked at 11.8 MMBPD in 1988 and has been declining at an ever-increasing rate since then. Currently, the latest estimates have Russian production at slightly under 10.7 MMBPD in 1990 and dropping to 9.5 MMBPD this year, which is a decline rate of over 10%.

The majority of the recent fall in USSR production is not due to the overall age and long term production profile of its reserves but due to political, economic, and technical problems. Because the reserves are known, and the potential for improvement is so great, we believe that after the solution of its political and economic problems, Russia can stem its production decline, and eventually show a positive production growth rate. This will not happen overnight.

Therefore, we are forecasting USSR production to continue to decline through 1998, but at lower rate each year. Thus, we expect USSR production to reach a bottom of slightly more than 9 MMBPD and remain at this level until 2000, at which point production is forecasted to begin to expand to a long term sustainable growth rate of 1% per year. Based on these growth rates, USSR crude oil production should recover during the end of the forecast period but only to 9.6 MMBPD by 2010.

China's production is expected to remain flat from 1990 through 1999 at slightly under 2.8 MMBPD. Unlike the Russians, the Chinese have decided not to advance political reform with economic reform and not to rely heavily on Western aid to stimulate oil production. We believe that under this approach, the best China can do is to maintain its crude production at today's levels. We are forecasting a positive growth rate for China starting in 2000 as eventually we expect the Chinese will open up their oil sector in order not to become net oil importers.

U.S. Crude Oil Supply

Specifically, our forecast is based on a decline rate of 2.0% per year for the United States through the forecast period. Thus, U.S. production is projected to decline from 7.3 MMBPD in 1990 to 4.5 MMBPD in the year 2010 (**Table A-11**).

Production in the United States has declined rapidly in the past few years, falling from 8.97 MMBPD in 1985 to an estimated 7.3 MMBPD in 1990 (**Figure A-14**). Our forecast calls for the decline to continue, but at a much slower rate. Production by the year 1995 will have slipped to 6.7 MMBPD, with further declines to 5.9 MMBPD by the year 2000. We do not expect that potential production from the Arctic National Wildlife Refuge in Alaska or from deep water offshore fields will be in production during our forecast period. The drop in U.S. production, combined with a lesser production decline in the United Kingdom, is expected to be offset by an increase in production by other non-OPEC nations.

PRODUCT PRICE STRUCTURE

As stated in the **Supply** section, our forecast assumes that the U.S. economy follows an underlying long-term GNP growth rate of 3% per year. With this economic growth rate we are assuming that the long term underlying inflation rate is 4% annually. The inflation rate is lower in the 1991 and 1992 period due to the effects of the lower economic activity, but it picks up again in 1997 and remains above 4% through 2000 due to the projected crude price spike in 1998.

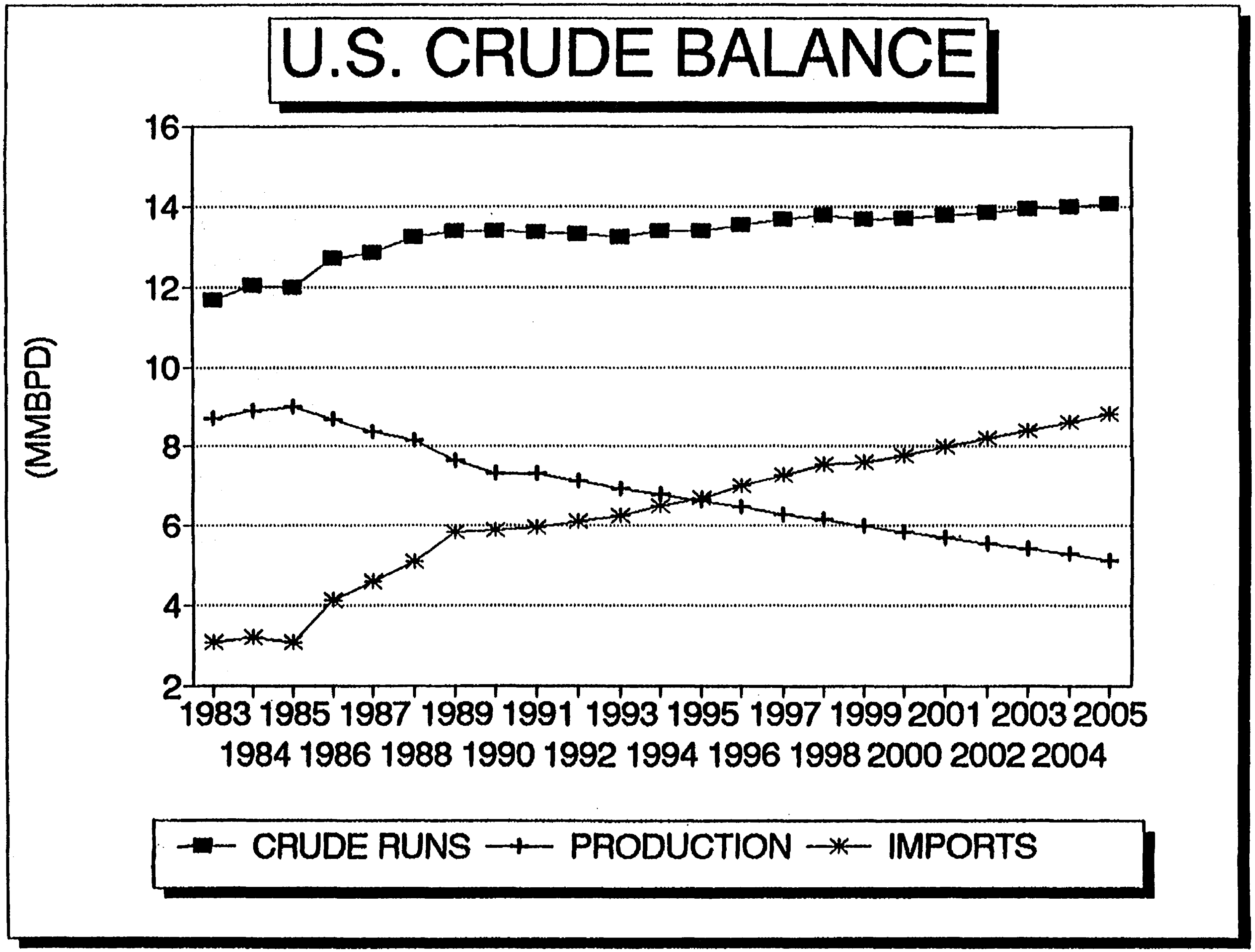

U.S. CRUDE BALANCE
(MMBPD)
16
14
12
10
8
6
4
2
1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
1984 1986 1988 1990 1992 1994 1996 1998 2000 2002 2004
CRUDE RUNS
PRODUCTION
IMPORTS

Figure A-14

Crude Prices

Spot West Texas Intermediate (WTI) crude prices are forecast to follow an upward trend in current and constant 1990 dollars over the forecast period through 2010 (**Figure A-15**). U. S. crude acquisition costs are expected to follow a similar pattern during this period (**Tables A-12, A-13**).

This price forecast is based on projections of the world supply/demand balance, which, based on moderate demand growth rates, and realistic future production profiles, results in an increasing capacity utilization rate for OPEC, the incremental world crude producer and price setter.

Spot WTI prices are projected to increase from close to $22/B in 1991 to almost $55/B in 2010. In constant 1990 dollars terms, spot WTI is forecasted to increase from around $21/B in 1991 to slightly over $24/B in 2010. This outlook is consistent with Saudi Arabian goals of maintaining a relatively stable (gradually increasing) crude price to support demand growth. Since Saudi Arabia is expected to remain the true incremental or swing producer, we expect their aspirations to continue to have an overriding effect on prices in the long term.

The forecasted crude price rise is not entirely linear, as we are projecting a price spike in 1998 as OPEC's capacity utilization temporarily increases near 90%. As in the past, we believe that this market environment sets the stage for a politically motivated (versus a supply constrained) price spike that will be temporary in nature due to the self-correcting reaction of demand declining.

We also have forecast the U.S. average acquisition cost of crude oil both in current and constant 1990 dollar terms, as this is a good yardstick to measure U.S. refining profitability and the relative strength of the refined product markets (**Figure A-16**).

Included in the forecast are the prices of Brent, Dubai, Maya (U.S. destinations), and the OPEC Crude Basket reference price. In constant 1990 dollars, the OPEC Crude Basket reference price is expected to increase from slightly less than $17.6/B in 1991 to $21.2/B in 2005, and $21.8/B in 2010. The corresponding spot Dubai price is forecasted from near $16.2/B in 1991 to over $18/B in 2000 and beyond. At the same time, the spot Brent price should rise from over $19.5/B in 1991 to over $23/B in 2005. Being a heavy crude in a weak resid market, Maya (US) prices are forecasted to increase from slightly over $12/B in 1991 to a bit more than $15/B in 2010.

Due to the current depressed resid market and frequent overhang of crude stocks, the relative strengths of the world's crudes need to be analyzed on a spread basis, as the above price increases are starting from a non-equilibrium point.

Crude Price Spreads

The forecasted crude spreads are reflective of a slightly heavying world crude slate, the production profiles of the various crudes, and the growing percentage of light products and declining percentage of residual fuel oil that comprises both the U.S. and the world's refined product demand barrel (**Table A-14**).

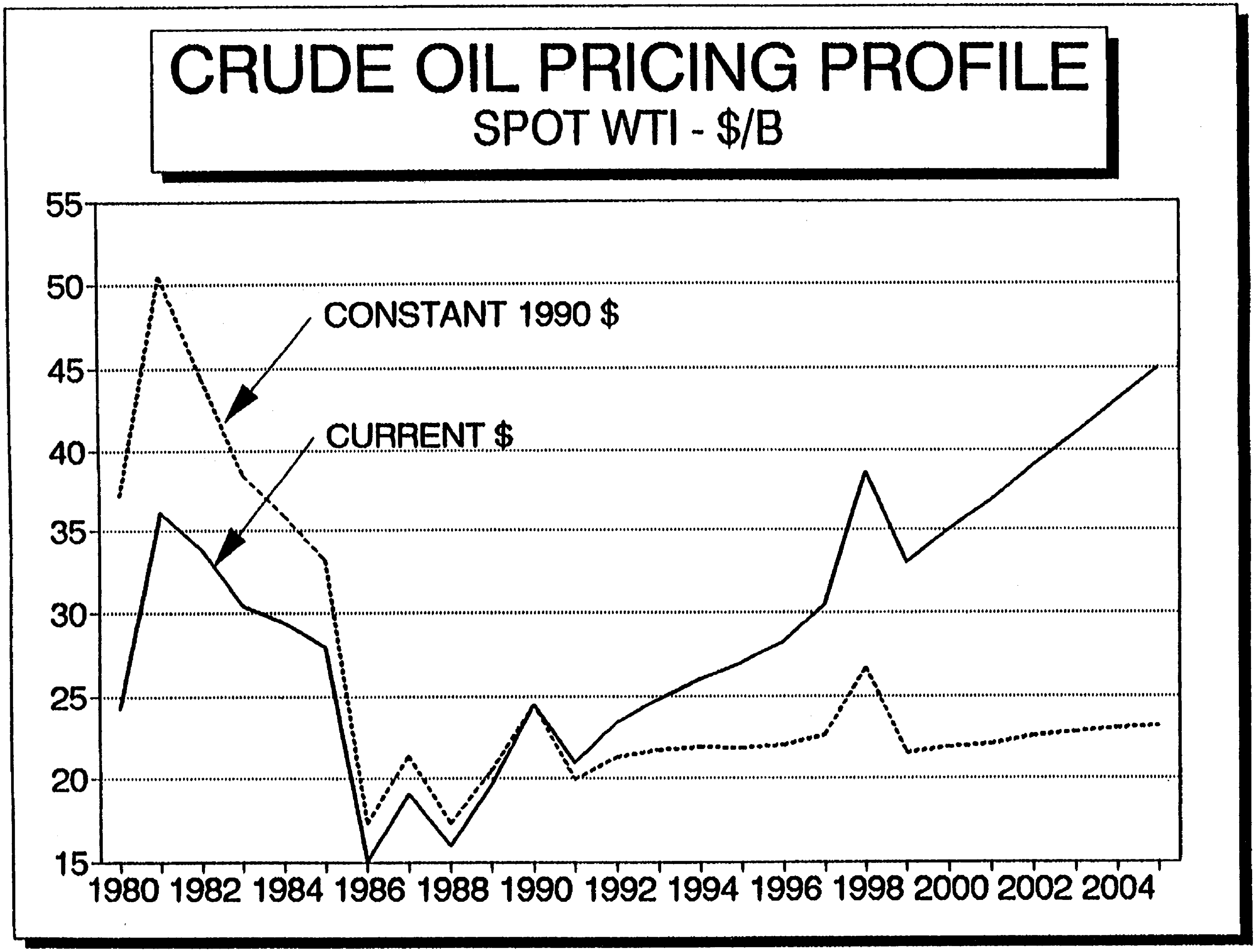

CRUDE OIL PRICING PROFILE
SPOT WTI - $/B
CONSTANT 1990 $
CURRENT $
55
50
45
40
35
30
25
20
15
1980 1982 1984 1986 1988 1990 1992 1994 1996 1998 2000 2002 2004

Figure A-15

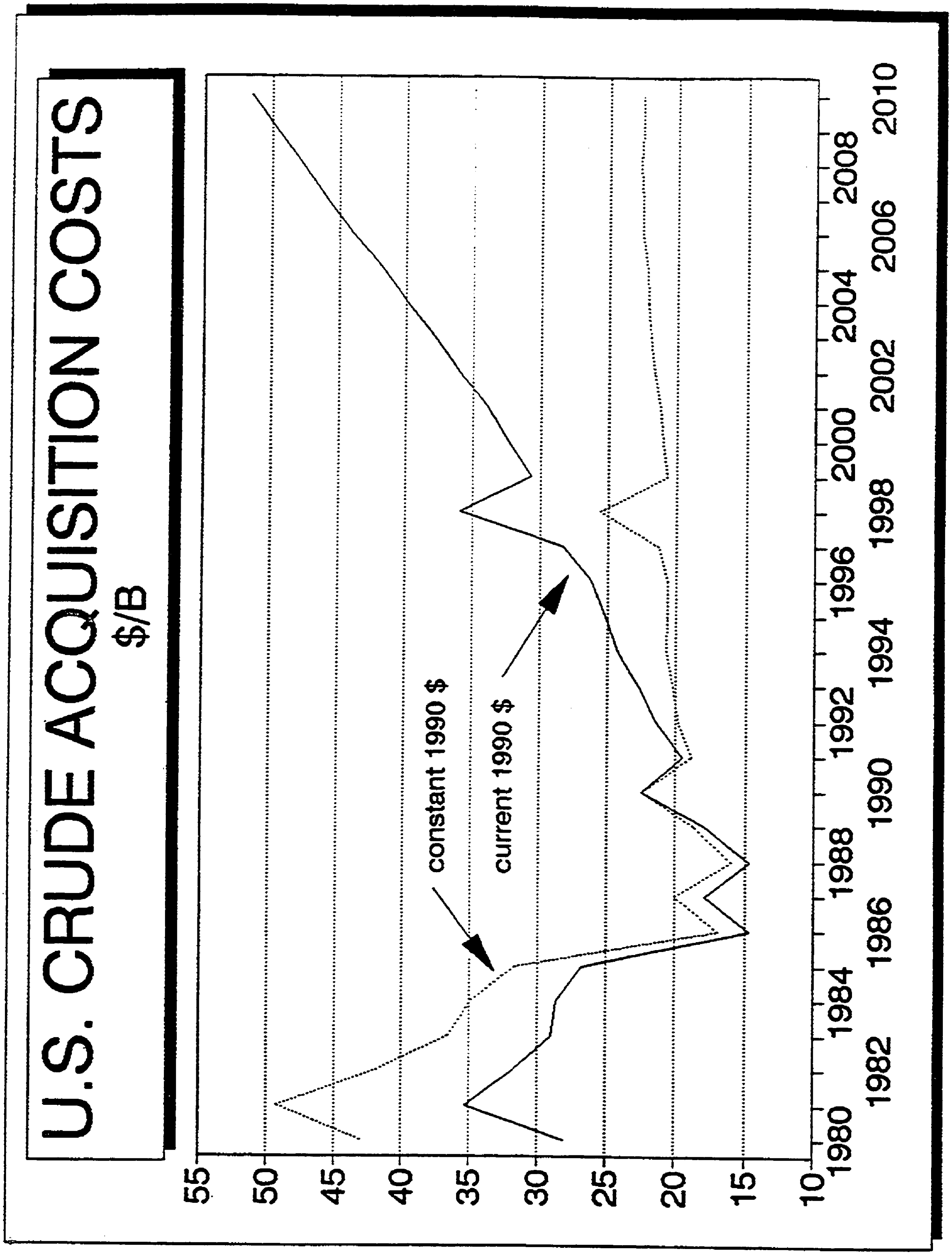

U.S. CRUDE ACQUISITION COSTS
$/B
constant 1990 $
current 1990 $
55
50
45
40
35
30
25
20
15
10
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010

Figure A-16

The WTI/U.S. Average Acquisition Cost of crude spread is expected to remain essentially constant in constant 1990 dollars over the forecast period at slightly over $1.5/B. This is a function of the increasing percentage of imports which offsets the relatively higher price of domestic crude.

The WTI/Brent spread is forecasted to increase in constant 1990 dollar terms through 1997 as U.S. production declines faster than the North Sea production (**Figure A-17**). The crude price spike in 1998 causes a brief jump in the differential. The spread is forecasted to remain constant from 2000 through 2006 as the decline in North Sea production accelerates, and later declines as a result of other light crudes potentially becoming available in the future.

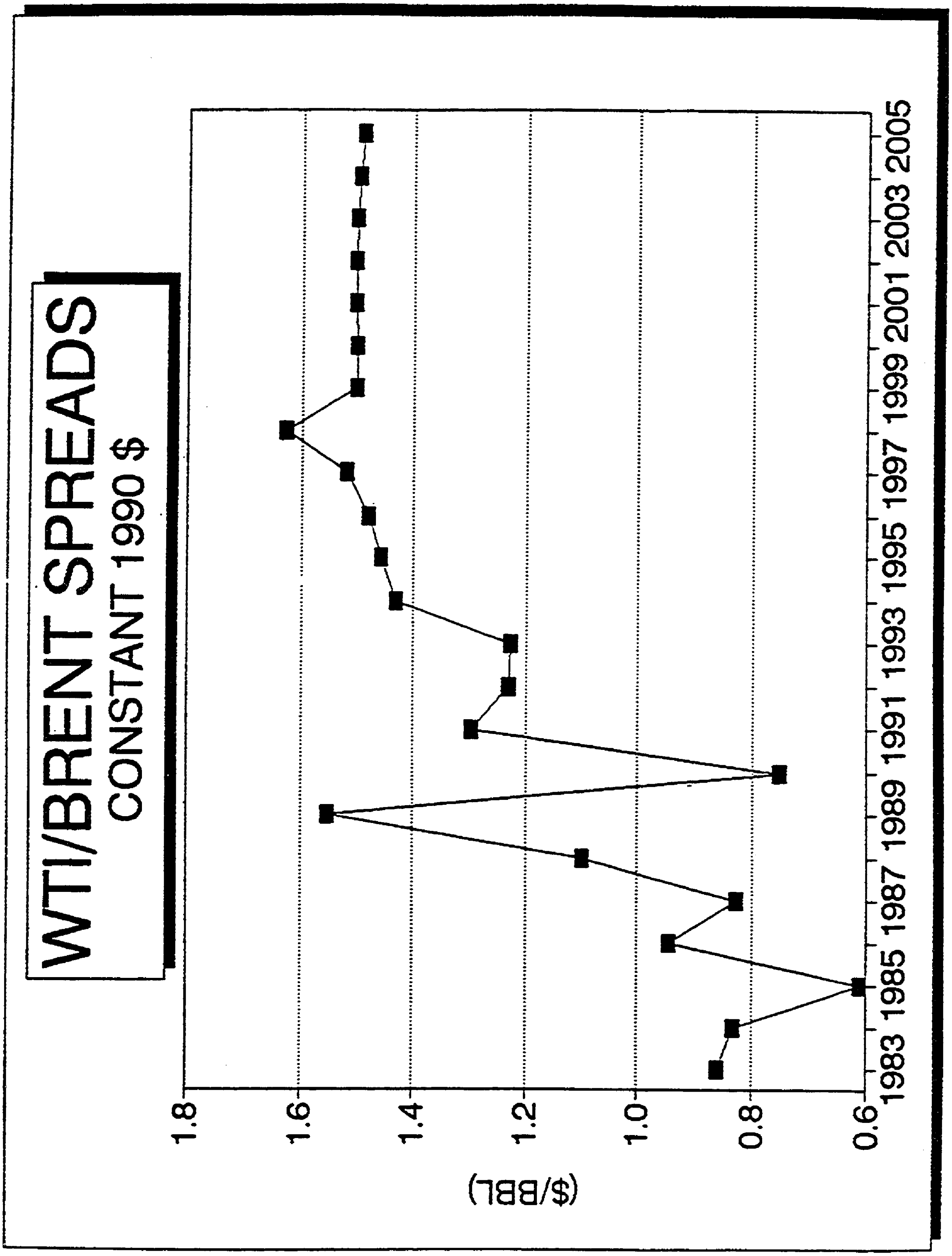
With WTI increasingly becoming mostly a "Midwest crude," and Dubai remaining a "world" crude, the WTI/Dubai spread is affected by the U.S. market and the global crude market. The WTI/Dubai spread in constant 1990 dollars is expected to decline from 1991's preliminary high level of almost $4.7/B and average closer to $4/B from 1992 through 1998 (**Figure A-18**). The 1991 spread has been temporary in nature due to below-average U.S. stocks this year, combined with a depressed resid market, and a depressed world crude market due to the stock overhang after the war.

Based on our WTI and Dubai (Gulf medium sour) price forecasts, the WTI/OPEC Crude Price Basket spread is also projected to increase in constant 1990 dollar terms over most of the forecast period.

U.S. Gulf Coast Refined Products Prices

In regard to U.S. motor gasoline supply and demand, we expect a slowing of the growth rate over the next few years due to increased prices and a turndown in the U.S. economy. Looking out over the next three to five years, we expect these price increases to result in only minor improvements in automobile efficiency, which will be more than offset by increases in the total number of miles driven (**Figure A-19**). This will allow for continued, modest growth in gasoline demand. Near the end of the decade, our forecast of increasing gasoline prices is expected to further dampen the growth rate in gasoline demand. Throughout the forecast period, domestic supply is expected to continue to provide nearly 95% of U.S. requirements (**Figure A-20**).

Besides the increasing total motor gasoline demand, we expect that mid-grade and premium unleaded gasolines will continue to capture an increasing share of the motor gasoline market before lining out at roughly 40% of the total gasoline demand in 1995 to 2000. Leaded gasolines are forecast to be essentially phased out of the market by the early 1990s. More important, the passage of the Clean Air Act will result in rapidly increasing requirements for reformulated gasoline. For the purposes of this analysis, the most important impact will be the increased reliance on MTBE as an octane enhancer.



WTI/BRENT SPREADS
CONSTANT 1990 $
($/BBL)
1.8
1.6
1.4
1.2
1.0
0.8
0.6
1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005

Figure A-17

Figure 108

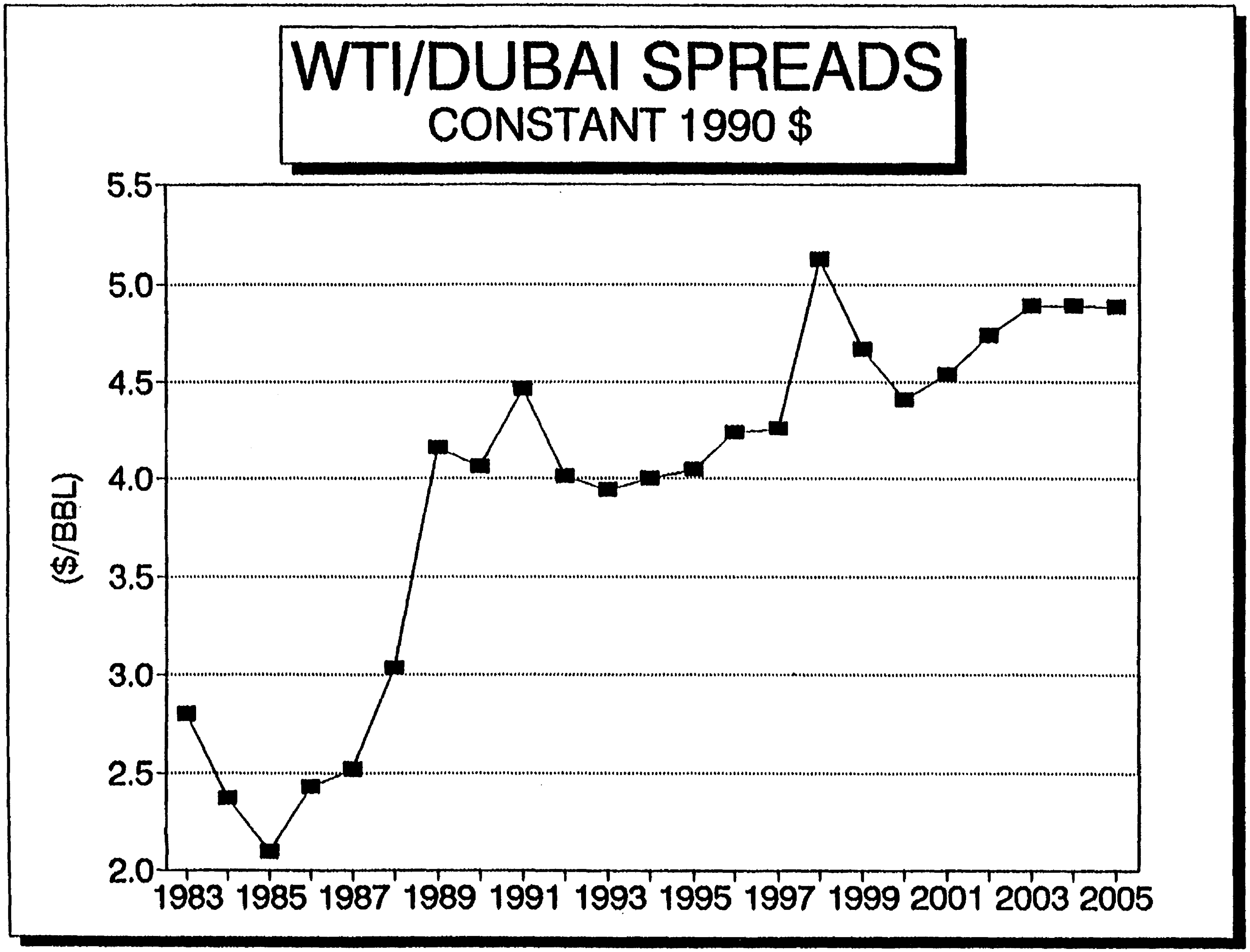
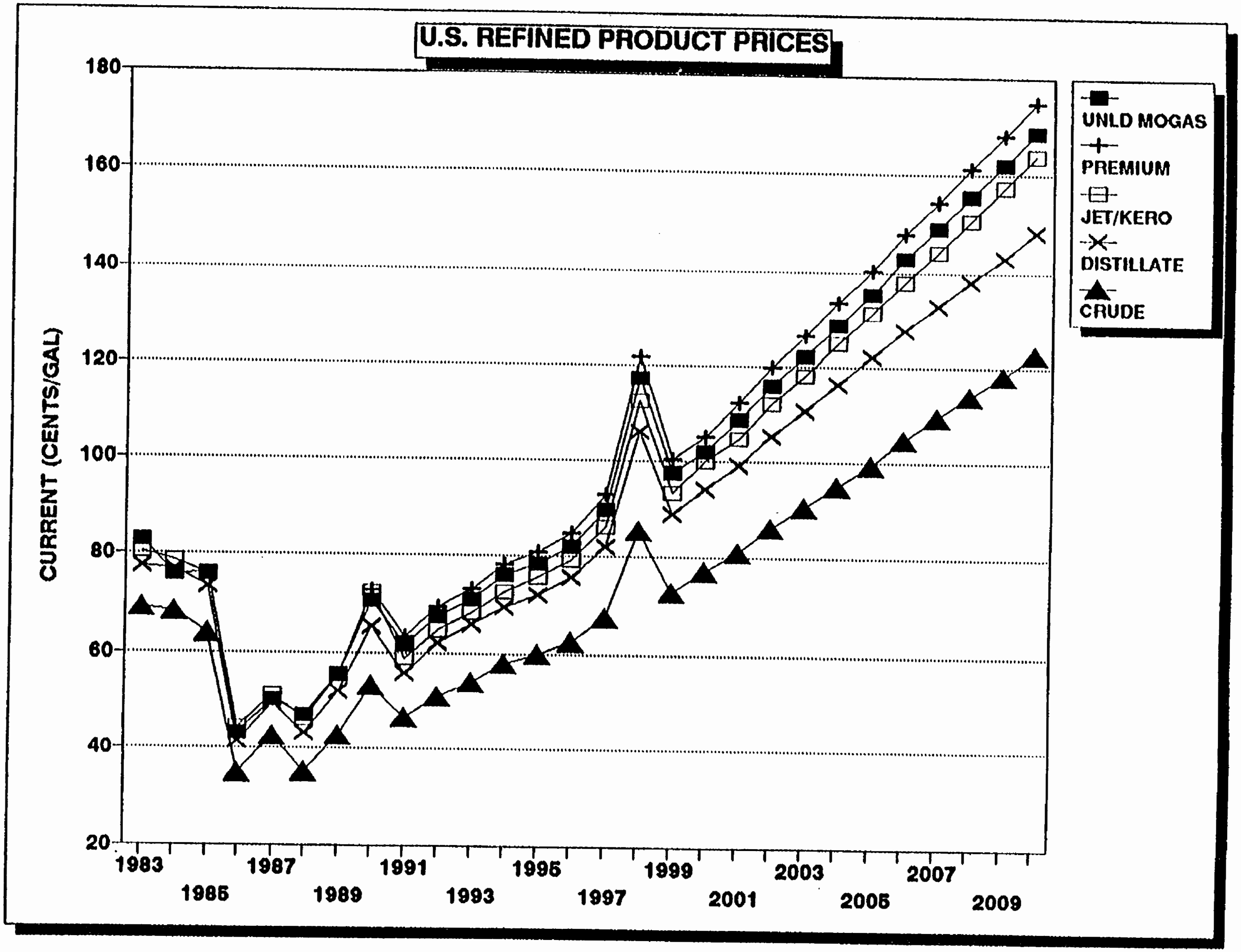


Figure A-18



U.S. REFINED PRODUCT PRICES
CURRENT (CENTS/GAL)
180
160
140
120
100
80
60
40
20
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
UNLD MOGAS
PREMIUM
JET/KERO
DISTILLATE
CRUDE

Figure A-19

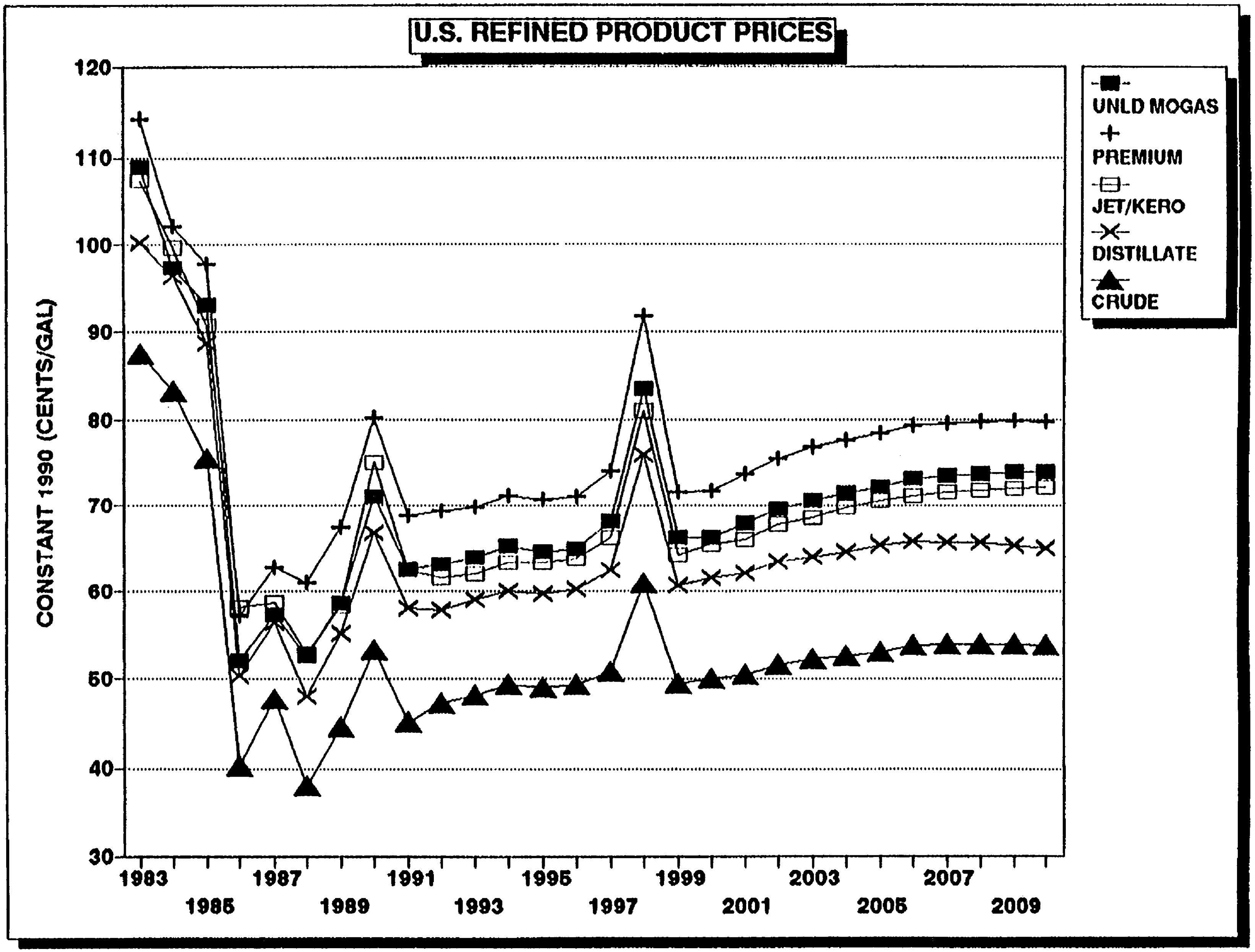

U.S. REFINED PRODUCT PRICES
CONSTANT 1990 (CENTS/GAL)
120
110
100
90
80
70
60
50
40
30
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
UNLD MOGAS
PREMIUM
JET/KERO
DISTILLATE
CRUDE

Figure A-20

As shown below, the differential between premium and regular grades of gasoline will begin to widen in the latter 1990s due to higher costs of providing incremental octane (**Tables A-15, A-16**).

MOTOR GASOLINE SPOT PRICES
(CENTS PER GALLON)

	1990	1995	1997	2000	2005	2010
Unleaded Premium	76.3	84.2	96.4	109.0	145.8	180.8
Unleaded Regular	70.3	78.4	89.8	101.8	135.1	168.5
Difference	6.0	5.8	6.6	8.0	10.7	12.3

We expect distillate demand to grow at a faster rate than motor gasoline demand. This growing demand is forecast to be met by essentially the same ratio of domestic supply versus imports. Our forecast is for domestic U.S. distillate demand to increase steadily to nearly 3.5 MMBPD by the year 2000. We expect distillate prices to follow much the same pattern as the gasoline price forecast.

Residual fuel oil demand in the United States has been fluctuating between 1.2 MMBPD and 1.4 MMBPD for the last seven years (**Figure A-21**). We expect that domestic consumption of residual fuel oil will decline slowly during the 1990s, with demand averaging 1.7 MMBPD in 2000, compared with 1.2 in 1990. The decline in production will be a bit less due to the effect of slightly increasing exports. Residual fuel oil prices will generally follow those of crude oil and other refined products; however, due to widened environmental restrictions, the premium on low sulfur fuel oil will tend to increase from approximately $5.40 per barrel in 1990 to $7.00 per barrel by 2000 (**Tables A-17, A-18**).

FUEL OIL SPOT PRICES
($/BB)

	1985	1990	1995	2000	2005	2010
Low S Resid	24.04	19.84	21.90	28.50	37.55	49.74
High S Resid	22.39	14.46	16.90	21.85	28.30	37.38

Refinery runs in 1990 are expected to be 13.4 MMBPD. This represents an almost continual increase in refinery runs since the 1983 low point of 11.8 MMBPD. Domestic demand for refined products is expected to be somewhat flat in 1991 relative to 1990, allowing for the increased production to go into inventory.

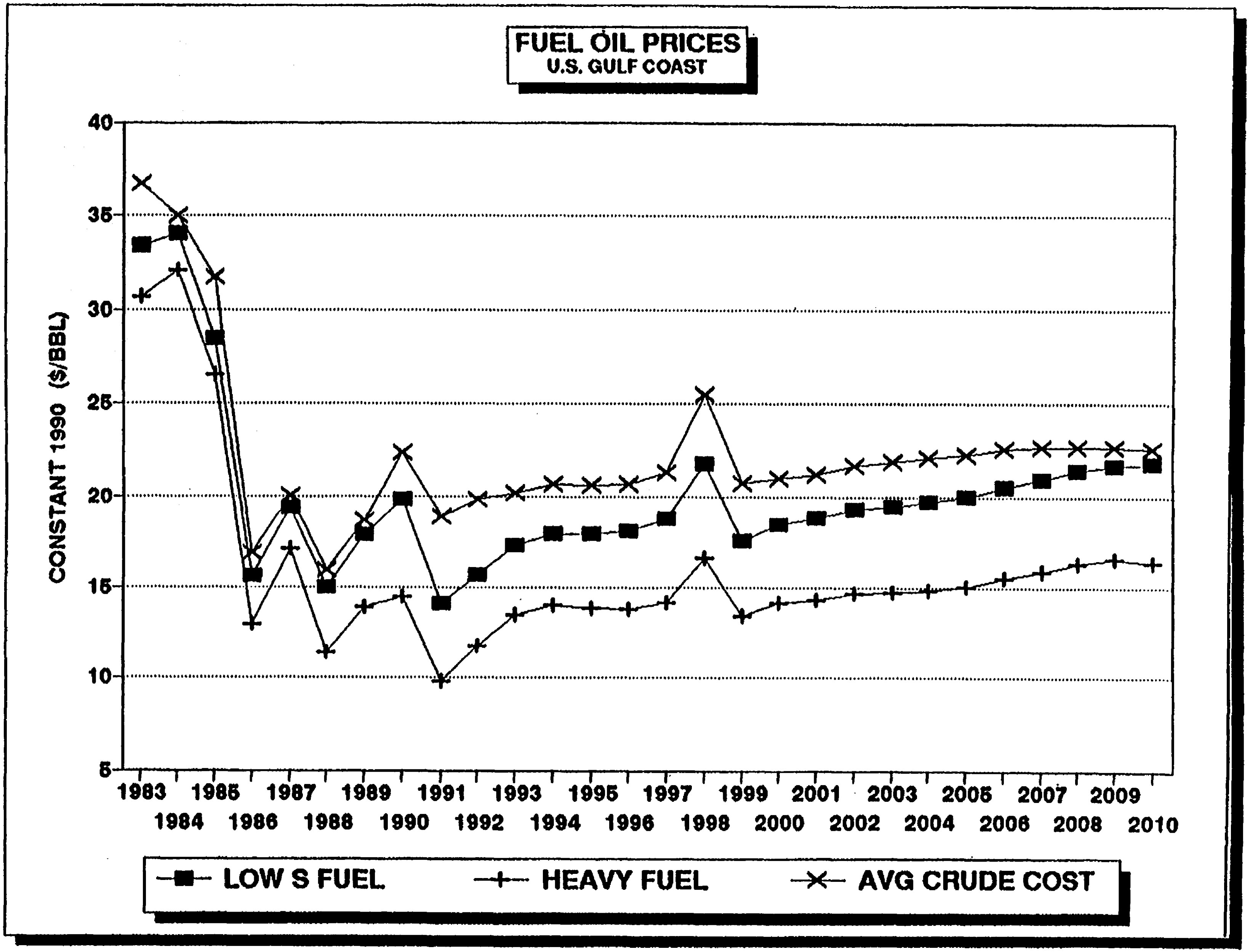

FUEL OIL PRICES
U.S. GULF COAST
CONSTANT 1990 ($/BBL)
40
35
30
25
20
15
10
5
1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005 2007 2009
1984 1986 1988 1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010
LOW S FUEL
HEAVY FUEL
AVG CRUDE COST

Figure A-21

Light Products

U.S. Gulf Coast light product prices are forecasted to move with the U.S. average acquisition cost of crude oil and trend upward throughout the forecast period. Light product prices are forecasted to rise faster than crude prices due to the increasing demand which results in higher refinery utilization, the lightening of the U.S. and the world's refined product slate, and the changing gasoline and distillate specifications which will raise these products' production costs.

The prices in this forecast are for gasoline which meets the requirements of the Clean Air Act, and for distillate that meets the new low sulfur diesel specifications. It is beyond the scope of this forecast to predict the price or price spread of any secondary market that may develop for non-highway or high sulfur distillate, and non-reformulated gasoline.

We do expect that the spreads between high and low sulfur distillate, if a two tier market were to develop on the U.S. Gulf Coast as it has on the West Coast, it would be of the same order of magnitude of 1.5 to 2.0 cents per gallon in 1990 dollars. This spread is close to the variable cash costs for incremental diesel desulfurization. The reformulated/non-reformulated gasoline spread on the U.S. Gulf Coast, if a two tier market were to develop, would eventually be expected to drop to the variable cash cost involved. However, in the near term with a shortfall of oxygenated blendstocks projected to be likely, the differential would be a function of the cost of MTBE.

Unleaded gasoline, jet-kero, and distillate prices are all projected to increase as a ratio to crude (U.S. Average Acquisition Cost) through the forecast period after they decline slightly from their 1991 levels, which are elevated by the large price swings in the first quarter of last year. Based on our individual product supply/demand balances for the U.S. and the global trends in light products consumption, we believe that on a ratio to crude basis, unleaded prices will increase more than distillate prices, and jet-kero prices will rise almost equally as fast as unleaded prices.

This outlook assumes, of course, that the end point specification of gasoline is not changed in any updating of the Clean Air Act. If the endpoint were reduced, we would expect gasoline prices to increase more than jet-kero prices if the volumetric gains were sufficient to require a constant jet-kero yield on crude runs.

On a spread to crude basis (**Figure A-22**), in constant 1990 dollars, the spot U.S. Gulf Coast unleaded regular gasoline spread is forecasted to decline from 1991's elevated level of near \$6.5/B to the \$6/B level in 1992 and 1993, and then increase to the \$7/B level in 1987 before the price spike in 1998. During the price spike, unleaded spreads are forecasted to shoot up to slightly over \$9/B versus crude and then drop back to the \$6.75 level in 1999 before gradually increasing over the balance of the forecast period to slightly over \$8/B in 2005.

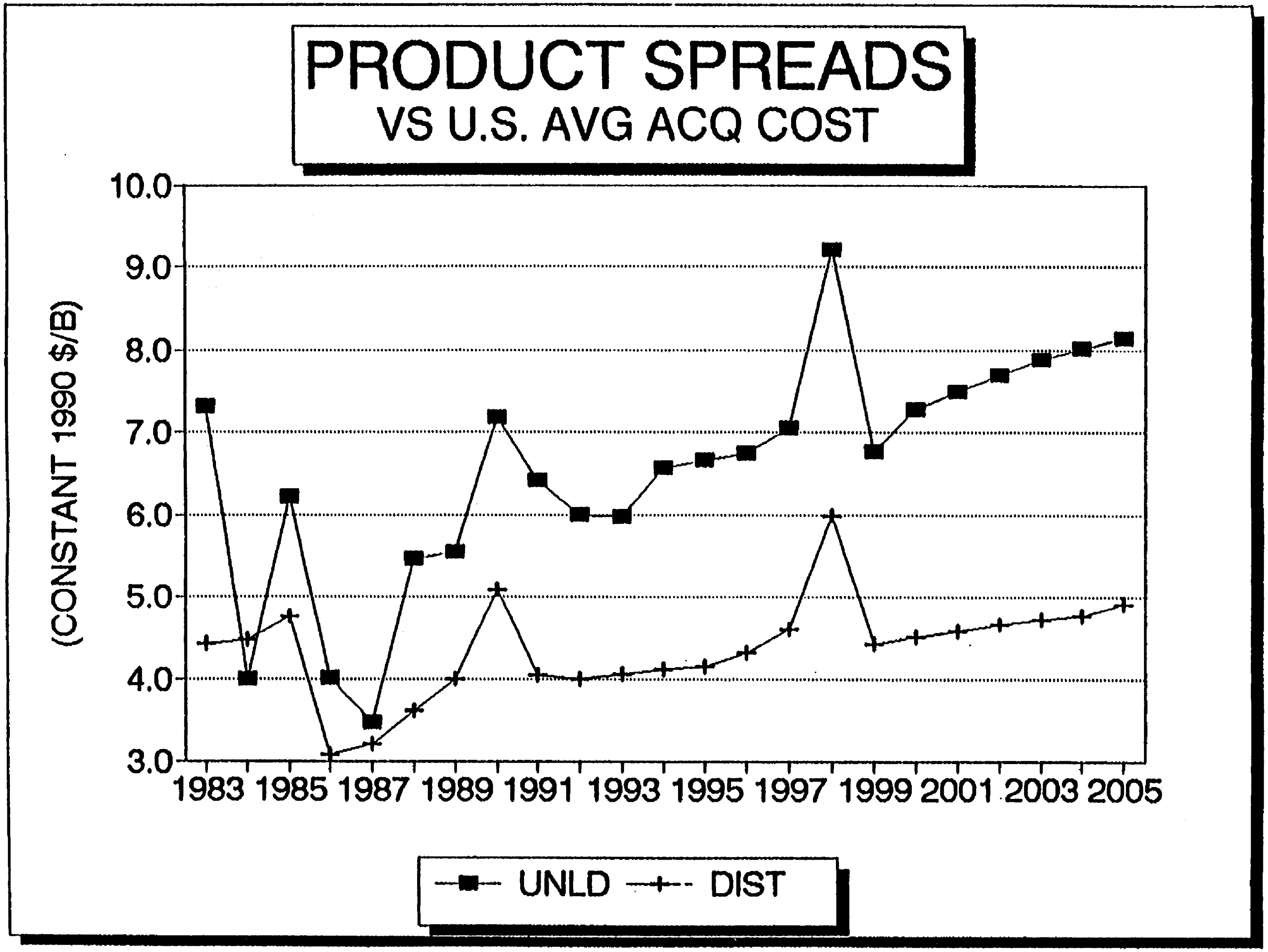

PRODUCT SPREADS
VS U.S. AVG ACQ COST
(CONSTANT 1990 $/B)
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
UNLD
DIST

Figure A-22

Spot U.S. Gulf Coast MTBE prices are forecasted to discontinue their past linkage with toluene prices starting in 1994, and to carry a premium due to the anticipated supply shortfall to meet demand if any additional areas decide to opt into the reformulated gasoline program. We expect MTBE/unleaded spreads to reflect total cash costs economics plus some capital pay back incentive from 1995 through 1997, when additional MTBE plants that are not even in the planning stages will come on line.

We are forecasting a recovery in the MTBE/unleaded spread to near the 35 cent/gallon level in 1992 through 1994, followed by an increase to a projected peak of 40 cents/gallon in 1995. Starting in 1996 this spread is projected to decline back towards the 35 cent/gallon level and then drop in 1999 after the crude price spike to slightly below the 30 cent/gallon level and remain there through 2005.

Based on our U.S. supply/demand balance, we are forecasting an increasing spot U.S. Gulf Coast jet-kero/distillate spread throughout the forecast period after a decline in 1992 due to elevated spreads in 1990 and 1991 with the Gulf War. On a constant 1990 dollar basis, jet-kero/distillate spreads are expected to decline from 2.8 cents/gallon in 1991 to the 2 cent /gallon level in 1992 and then steadily increase to the 4.75 cent/gallon level in 2005 with a upward blip in 1998 due to the crude price spike.

Residual Fuel Oils

Spot U.S. Gulf Coast residual fuel oil prices are expected to trend upwards with crude prices, but at a lower rate due to our projection of low U.S. and world growth rates for residual fuel and a declining market share that has been shrinking since 1971 (**Figure A-23**).

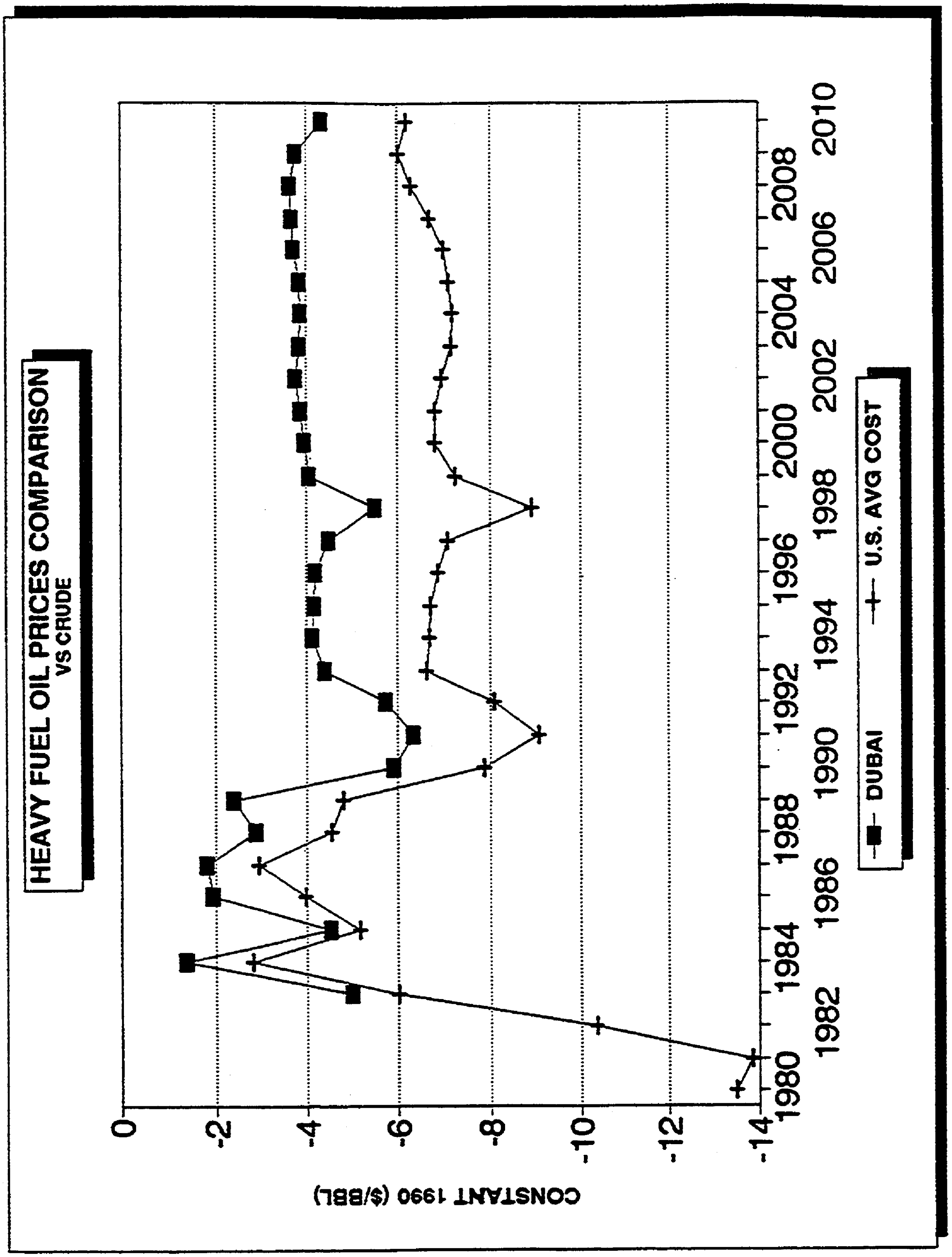
We are forecasting spot U.S. Gulf Coast LSFO (0.7% S) and HSFO (3.0% S) prices to increase, in current dollars, from their depressed 1991 levels of slightly over $15.35/B and $11.35/B to slightly over $19.5/B and $15.5/B, respectively, in 1992 and then gradually rise to almost $37/B for LSFO and $27.75/B for HSFO in 2005.

In constant 1990 dollars, the numbers reflect our "bearish" assessment of the future resid market. Resid prices should average close to $14.5/B for LSFO and $10.75/B for HSFO in 1991, increase to near $18/B for LSFO and $14.25/B for HSFO in 1992, and then remain essentially flat, with LSFO at $19/B and HSFO at $14.25/B in 2005, except for the crude price spike in 1998.

On a percent-of-crude basis, we are forecasting spot U.S. Gulf Coast LSFO prices to rebound from their depressed 1991 level of 80% to the 90% level for the balance of the forecast period, with a dip to the 85% level in 1998 during the crude price spike. The spot New York LSFO price is expected to follow a similar pattern but at slightly above the 100% level due to its location and quality differentials.

The spot U.S. Gulf Coast HSFO price on a percent of crude basis is expected to rebound from its depressed 1991 level of 60% to above the 70% level in 1992 and then decline to under the 70% level for the balance of the forecast period, with a dip in 1998.

On an spread-to-crude basis, in constant 1990 dollars, the spot U.S. Gulf Coast HSFO/Dubai price spread is forecasted to average less than $(3.50)/B in 1991, decrease to $(3/B) in 1992, and then increase to the $(4/B) level in 2005.



HEAVY FUEL OIL PRICES COMPARISON
VS CRUDE
CONSTANT 1990 ($/BBL)
0
-2
-4
-6
-8
-10
-12
-14
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
DUBAI
U.S. AVG COST

Figure A-23

The spot U.S. Gulf Coast LSFO/HSFO differential is forecasted to gradually increase in constant 1990 dollars from near the $3.5/B level in the next several years to the $4.75/B level in 2005 with an upward blip in 1989.

U.S. Gulf Coast Refining Margins

Based on our crude and refined products forecast, we are projecting a rise in U.S. Gulf Coast cash margins of about $1.25 per barrel in constant 1990 dollars over the forecast period (**Figure A-24**). Specifically, we expect margins to average close to $2.30 per barrel in 1991, drop to the $2 per barrel level in 1992 and 1993, and then gradually increase to the $3.25 per barrel level in 2005, with a one-year spike in 1998.

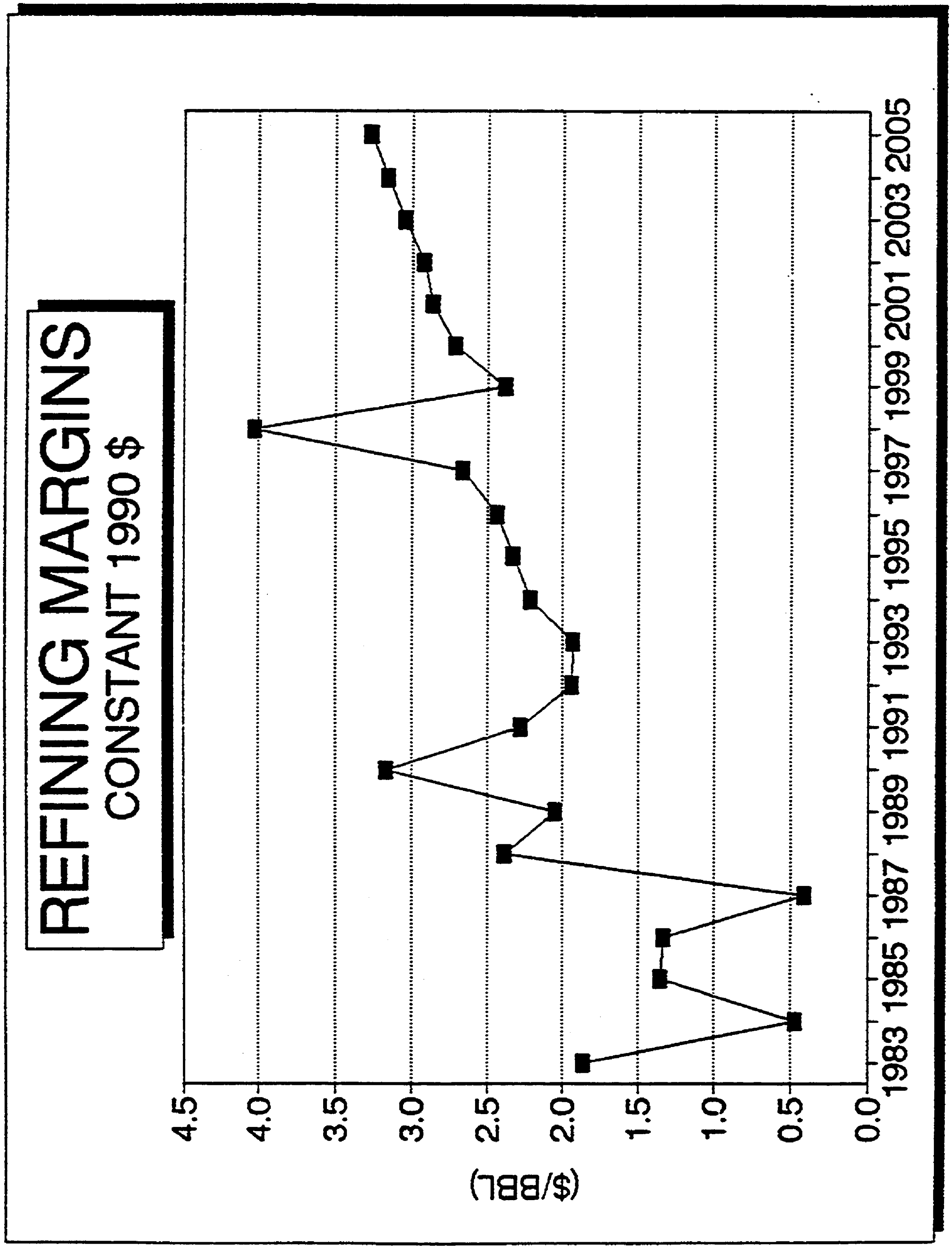

REFINING MARGINS
CONSTANT 1990 $
($/BBL)
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005

Figure A-24

ADDENDUM TO

SECTION 1

SUBSTANTIATING TABLES

WORLD DEMAND GROWTH RATES
(PERCENT)

	OECD				NON-OECD								
	NORTH AMERICA	OECD EUROPE	OECD PACIFIC	TOTAL OECD	USSR	CHINA	EUROPE	LATIN AMERICA	ASIA	MIDDLE EAST	AFRICA	TOTAL NON-OECD	TOTAL WORLD
1984	3.12	(0.25)	3.93	2.10	(1.31)	3.57	(0.97)	0.68	19.34	8.89	1.69	3.40	2.70
1985	1.70	(0.51)	(0.36)	(0.67)	0.33	5.75	2.94	1.58	(12.83)	8.21	0.56	(0.08)	(0.04)
1986	3.25	3.60	0.56	2.95	0.77	8.20	1.43	5.32	6.94	(1.72)	1.10	2.67	2.83
1987	2.36	1.32	0.93	1.79	(1.75)	10.55	(15.49)	3.16	6.49	1.75	3.89	0.94	1.42
1988	4.23	1.39	4.60	3.29	(1.11)	0.00	0.00	0.00	9.76	3.45	5.26	1.87	2.68
1989	0.42	0.80	4.92	1.27	(1.46)	6.82	(1.10)	3.06	8.44	3.33	2.50	2.49	1.77
1990	(1.94)	0.40	4.69	(0.11)	(0.45)	(1.28)	(12.92)	0.00	8.61	3.55	3.90	(0.04)	(0.05)
1991	(2.25)	3.66	3.84	0.75	(3.23)	3.45	(3.23)	1.58	7.17	1.54	0.94	1.00	0.82
1992	1.20	0.60	2.20	1.20	(5.00)	3.00	(5.00)	0.50	5.00	3.00	0.50	(0.06)	0.82
1993	1.03	1.52	2.71	1.44	3.14	4.00	7.14	1.52	3.28	2.35	8.00	3.39	1.51
1994	1.02	1.50	2.90	1.55	(2.00)	2.00	0.00	0.05	5.00	3.00	0.50	1.21	1.38
1995	1.00	1.25	2.50	1.37	0.00	2.00	0.50	1.00	4.00	2.50	0.50	1.59	1.43
1996	1.00	1.25	2.50	1.35	0.50	2.00	1.00	1.00	3.00	2.50	0.50	1.53	1.42
1997	1.00	1.25	2.50	1.33	0.50	2.00	1.00	1.00	3.00	2.50	0.50	1.54	1.42
1998	1.00	1.25	2.50	1.39	0.50	2.00	1.00	1.00	3.00	2.50	0.50	1.68	1.51
1999	(2.00)	(2.00)	(1.00)	(1.85)	(0.75)	1.00	(1.50)	(1.50)	(2.00)	(0.75)	0.00	(1.83)	(1.84)
2000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2005	0.75	1.00	2.00	1.00	1.00	1.75	1.50	0.90	2.40	2.00	0.50	1.00	1.29
2010	0.75	1.00	2.00	1.05	1.00	1.75	1.50	0.90	2.40	2.00	0.50	1.00	1.25

Table A-1

WORLD PETROLEUM DEMAND
(MMB/D)

	OECD				NON-OECD								
	NORTH AMERICA	OECD EUROPE	OECD PACIFIC	TOTAL OECD	USSR	CHINA	EUROPE	LATIN AMERICA	ASIA	MIDDLE EAST	AFRICA	TOTAL NON-OECD	TOTAL WORLD
1983	16.68	11.77	5.35	33.79	9.18	1.68	2.06	4.41	3.46	2.46	1.77	25.03	58.82
1984	17.20	11.74	5.56	34.50	9.06	1.74	2.04	4.44	4.13	2.68	1.80	25.88	60.38
1985	17.23	11.68	5.36	34.27	9.09	1.84	2.10	4.51	3.60	2.90	1.81	25.86	60.13
1986	17.79	12.10	5.39	35.28	9.16	1.99	2.13	4.75	3.85	2.85	1.83	26.55	61.83
1987	18.21	12.26	5.44	35.91	9.00	2.20	1.80	4.90	4.10	2.90	1.90	26.80	62.71
1988	18.98	12.43	5.69	37.09	8.90	2.20	1.80	4.90	4.50	3.00	2.00	27.30	64.39
1989	19.06	12.53	5.97	37.56	8.77	2.35	1.78	5.05	4.88	3.10	2.05	27.98	65.53
1990	18.69	12.58	6.25	37.52	8.37	2.32	1.55	5.05	5.30	3.25	2.13	27.97	65.50
1991	18.27	13.04	6.49	37.80	8.10	2.40	1.50	5.13	5.68	3.30	2.15	28.25	66.04
1992	18.49	13.12	6.63	38.25	7.97	2.50	1.40	5.25	6.10	3.40	2.25	28.87	67.12
1993	18.68	13.32	6.81	38.80	8.22	2.60	1.50	5.33	6.30	3.48	2.43	29.85	68.65
1994	18.87	13.52	7.01	39.40	8.06	2.65	1.50	5.36	6.62	3.58	2.44	30.21	69.61
1995	19.06	13.69	7.19	39.94	8.06	2.71	1.51	5.41	6.88	3.67	2.45	30.69	70.63
1996	19.25	13.86	7.37	40.48	8.10	2.76	1.52	5.46	7.09	3.76	2.47	31.16	71.64
1997	19.44	14.03	7.55	41.02	8.14	2.81	1.54	5.52	7.30	3.85	2.48	31.64	72.66
1998	19.64	14.21	7.74	41.59	8.18	2.87	1.59	5.57	7.52	3.95	2.49	32.17	73.76
1999	19.24	13.92	7.66	40.82	8.12	2.90	1.56	5.49	7.37	3.65	2.49	31.58	72.40
2000	19.24	13.92	7.66	40.82	8.12	2.90	1.56	5.49	7.37	3.65	2.49	31.58	72.40
2005	20.05	14.62	8.43	43.10	8.53	3.15	1.68	5.74	8.30	4.02	2.55	33.97	77.07
2010	21.07	15.35	9.27	45.69	8.95	3.43	1.81	6.00	9.34	4.42	2.61	36.56	82.25

Table A-2

WORLD CRUDE OIL PRODUCTION
(MB/D)

	OPEC														NON-OPEC							TOTAL	
	MIDEAST OPEC							OTHER OPEC															
							SUB							TOTAL								NON-	TOTAL
	SAUDI	IRAN	IRAQ	KUWAIT	UAE	QATAR	TOTAL	VENZ	NIGER	INDO	LIBYA	ALGER	OTHER	OPEC	USA	MEX	UK	CAN	USSR	CHINA	OTHER	OPEC	WORLD
1983	5086	2440	1005	1064	1149	295	11039	1801	1241	1343	1105	968	394	17891	8688	2689	2291	1356	11684	2120	6248	35076	52967
1984	4663	2174	1209	1157	1146	394	10743	1798	1388	1412	1087	1014	415	17857	8879	2780	2480	1438	11576	2296	6897	36346	54203
1985	3388	2250	1433	1023	1193	301	9588	1677	1495	1325	1059	1037	453	16634	8971	2745	2530	1471	11250	2505	7540	37012	53646
1986	4870	2035	1690	1419	1330	308	11652	1787	1467	1390	1034	945	459	18734	8680	2435	2539	1474	11540	2620	7850	37138	55872
1987	4265	2298	2079	1585	1541	293	12061	1752	1341	1343	972	1048	329	18846	8349	2548	2406	1535	11690	2690	8242	37460	56306
1988	5086	2240	2685	1492	1656	346	13505	1903	1450	1342	1175	1040	370	20785	8140	2512	2232	1616	11823	2730	8669	37722	58507
1989	5056	2863	2822	1802	1960	391	14894	1907	1693	1409	1145	750	564	22362	7613	2513	1788	1560	11420	2760	8917	36571	58933
1990	6477	3088	2008	1170	2120	385	15248	2137	1829	1399	1350	825	562	23350	7313	2548	1825	1529	10681	2769	9333	35997	59347
1991	8157	3330	294	137	2422	387	14726	2365	1949	1597	1468	860	591	23557	7339	2669	1732	1553	9697	2797	10090	35878	59435
1992	7871	3269	1364	530	2387	386	15807	2260	1920	1462	1437	852	581	24320	7230	2660	1825	1530	9500	2825	10400	35970	60290
1993	7261	3325	2393	1314	2440	392	17125	2375	1925	1362	1425	859	572	25643	7050	2660	1775	1530	9215	2850	10970	36050	61693
1994	7222	3200	2800	1937	2300	400	17859	2400	1930	1300	1400	860	560	26309	6930	2655	1734	1570	9126	2871	11314	36200	62509
1995	7381	3300	3100	2000	2200	425	18406	2550	1945	1250	1400	860	530	26941	6757	2677	1708	1575	9100	2890	11764	36471	63411
1996	7423	3400	3100	2000	2100	425	18448	2600	1950	1200	1450	865	627	27040	6588	2703	1682	1570	9075	2890	12877	37385	64425
1997	7985	3400	3200	2100	2150	450	19285	2600	1980	1150	1425	865	525	27830	6423	2717	1657	1570	9080	2895	13047	37389	65219
1998	8523	3300	3300	2150	2200	475	19948	2650	2050	1125	1450	875	522	28620	6263	2730	1632	1570	9100	2898	13519	37712	66332
1999	8420	3200	3300	2000	2200	450	19570	2600	2000	1100	1450	860	520	28100	6106	2744	1607	1562	9200	2890	13392	37501	65601
2000	7843	3100	3200	2000	2000	450	18593	2600	2000	1075	1400	850	510	27028	5953	2758	1583	1554	9450	2850	13832	37980	65008
2005	9631	3400	3750	2350	2350	500	21981	2850	2100	950	1400	830	500	30611	5114	2827	1468	1478	9543	2927	15234	38591	69201
2010	10148	3400	4200	2700	2450	500	23398	3000	2000	850	1400	800	480	31928	4509	2908	1360	1406	9680	3080	18979	41922	73852

Table A-3

OPEC CRUDE OIL PRODUCTION CAPACITIES
(MB/D)

	MIDEAST OPEC							OTHER OPEC						TOTAL
	SAUDI	IRAN	IRAQ	KUWAIT	UAE	QATAR	SUBTO	VENZ	NIGER	INDO	LIBYA	ALGER	OTHER	OPEC
1986	8600	3000	3000	2500	2000	600	19700	2500	1700	1500	1600	900	530	28430
1987	8600	3000	3000	2500	2000	600	19700	2500	1700	1500	1600	900	530	28430
1988	8600	3000	3000	2500	2000	600	19700	2500	1700	1500	1600	900	530	28430
1989	8600	3000	3000	2500	2000	600	19700	2500	1700	1500	1600	900	530	28430
1990	8600	3000	3100	1445	2200	600	18945	2500	1800	1500	1650	900	530	27825
1991	8600	3400	1950	17	2425	600	16992	2550	1900	1500	1700	900	590	26132
1992	9000	3500	3100	326	2500	597	19023	2900	2050	1450	1600	900	590	28513
1993	9500	3500	3100	1127	2500	594	20321	3200	2200	1400	1500	900	560	30081
1994	10000	3500	3100	1937	2500	591	21628	3200	2200	1350	1500	900	530	31308
1995	10500	3500	3100	2000	2500	588	22188	3200	2200	1300	1500	895	527	31810
1996	10500	3500	3100	2000	2500	585	22185	3200	2189	1250	1493	890	525	31732
1997	10500	3500	3200	2500	2500	582	22782	3200	2178	1200	1485	885	522	32252
1998	10500	3500	3300	2500	2500	579	22879	3200	2167	1175	1478	880	519	32298
1999	10500	3500	3400	2500	2500	576	22976	3200	2156	1150	1470	875	517	32344
2000	10500	3500	3500	2500	2500	573	23073	3200	2145	1125	1463	870	514	32390
2001	10900	3500	3600	2700	2500	571	23771	3200	2135	1100	1456	865	512	33039
2002	11300	3500	3700	2700	2500	568	24268	3200	2124	1075	1448	860	509	33484
2003	11700	3500	3800	2700	2500	565	24765	3200	2114	1050	1441	855	506	33931
2004	12100	3500	3900	2700	2500	562	25262	3200	2103	1025	1434	850	504	34378
2005	12500	3500	4000	2700	2500	559	25759	3200	2092	1000	1427	845	502	34825
2006	12900	3500	4100	2800	2500	555	26355	3200	2000	975	1422	840	499	35291
2007	13300	3500	4100	2800	2500	550	26750	3000	1900	950	1417	835	496	35348
2008	13700	3500	4200	2900	2500	545	27345	3000	1800	925	1412	830	493	35805
2009	14000	3500	4300	3000	2500	530	27830	3000	1750	900	1407	825	490	36202
2010	14500	3500	4400	3000	2500	520	28420	3000	1700	872	1400	820	487	36699

Table A-4

U.S. PETROLEUM PRODUCT SUPPLY AND DEMAND

(MB/D)

	SUPPLY								DEMAND		PRODUCT
	CRUDE RUNS	PROCESS GAIN	NGL PROD'N	OTHER PROD'N	TOTAL PROD'N	ET FRO INVEN	PRODUCT IMPORTS	TOTAL SUPPLY	DOMESTIC DEMAND	PRODUCT EXPORTS	INVENTORIES (MMBBL)
1983	11685	487	1559	119	13850	234	1722	15806	15231	575	731
1984	12044	554	1630	109	14337	(81)	2011	16267	15726	541	760
1985	12002	558	1609	115	14284	153	1866	16303	15726	577	705
1986	12716	617	1551	107	14991	(124)	2045	16912	16281	631	750
1987	12854	639	1595	98	15186	88	2004	17278	16665	613	718
1988	13246	655	1625	94	15620	29	2295	17944	17283	661	707
1989	13401	661	1546	88	15696	129	2217	18042	17325	717	660
1990	13409	667	1551	99	15726	(150)	2079	17655	16988	745	715
1991	13350	676	1640	105	15746	(1)	1782	17527	16682	844	715
1992	13322	650	1610	105	15687	(59)	1893	17521	16849	767	737
1993	13262	655	1615	105	15637	22	2029	17688	17016	739	729
1994	13391	661	1617	109	15778	(19)	2079	17838	17185	733	735
1995	13416	663	1619	115	15813	(19)	2115	17909	17357	726	742
1996	13550	669	1610	163	15992	(19)	2160	18133	17529	720	749
1997	13684	676	1611	191	16162	(21)	2192	18333	17704	714	756
1998	13802	682	1612	182	16278	41	2187	18506	17880	717	741
1999	13692	676	1615	208	16191	0	1979	18170	17524	714	741
2000	13721	678	1618	238	16255	(10)	1957	18202	17524	714	745
2005	14087	696	1622	270	16675	(18)	2206	18863	18144	723	752
2010	14462	714	1636	288	17100	(18)	2487	19569	18789	732	759

Table A-5

U.S.
MOTOR GASOLINE SUPPLY/DEMAND
(MB/D)

	SUPPLY				DEMAND			INVENTORY (MMBBL)	
	PRO-DUCTION	IMPORT	NET FROM INVEN	TOTAL	DOMESTIC (MB/D)	DOMESTIC DEL %	EXPORT	TOTAL	FINISHED
1983	6340	247	45	6632	6622	1.3	10	222	186
1984	6454	299	(54)	6699	6693	1.1	6	243	205
1985	6419	381	41	6841	6831	2.1	10	223	190
1986	6752	326	(11)	7067	7034	3.0	33	233	194
1987	6842	384	15	7241	7206	2.4	35	226	189
1988	6956	405	(3)	7358	7336	1.8	22	228	190
1989	6963	369	35	7367	7328	(0.1)	39	213	177
1990	6975	333	(14)	7294	7238	(1.2)	56	221	182
1991	6972	293	26	7291	7212	(0.4)	79	210	173
1992	7045	300	(47)	7298	7248	0.5	50	232	190
1993	7038	300	(3)	7335	7285	0.5	50	233	191
1994	7092	300	(4)	7388	7339	0.7	50	235	193
1995	7147	300	(4)	7443	7394	0.7	50	237	194
1996	7202	300	(4)	7498	7449	0.7	50	239	196
1997	7258	300	(4)	7554	7505	0.8	50	240	197
1998	7305	300	5	7610	7561	0.7	50	238	195
1999	7234	300	0	7534	7485	(1.0)	50	238	195
2000	7235	280	(1)	7514	7485	0.0	50	239	196
2005	7408	320	(5)	7723	7654	0.5	50	245	201
2010	7542	340	(5)	7877	7823	0.5	50	251	206

Table A-6

U.S.
JET KEROSENE SUPPLY/DEMAND
(MB/D)

	SUPPLY				DEMAND			ENDING
	PRO-		NET FROM		DOMESTIC			INVENTORY
	DUCTION	IMPORT	INVEN	TOTAL	(MB/D)	DEL %	EXPORT	(MMBBL)
1983	816	29	(1)	844	839	4.4	5	32
1984	919	48	(8)	959	953	13.6	6	35
1985	983	30	4	1017	1005	5.5	12	34
1986	1098	48	(25)	1121	1105	10.0	16	43
1987	1138	64	2	1204	1181	6.9	23	42
1988	1164	87	12	1263	1236	4.7	27	38
1989	1196	102	9	1307	1284	3.9	23	34
1990	1280	96	(31)	1345	1306	1.7	39	46
1991	1270	60	10	1340	1300	(0.5)	40	42
1992	1330	90	(11)	1409	1384	6.5	25	46
1993	1408	90	(11)	1487	1462	5.6	25	50
1994	1478	95	(7)	1566	1541	5.4	25	52
1995	1549	100	(3)	1646	1621	5.2	25	53
1996	1580	104	(3)	1681	1657	2.2	25	55
1997	1612	110	(3)	1719	1694	2.2	25	56
1998	1642	116	0	1758	1732	2.2	20	56
1999	1637	121	0	1758	1732	0.0	15	56
2000	1634	126	(2)	1758	1732	0.0	15	56
2005	1763	151	(3)	1911	1885	1.8	25	61
2010	1892	175	(3)	2064	2038	1.8	25	66

Table A-7

U.S.
DISTILLATE SUPPLY/DEMAND
(MB/D)

	SUPPLY				DEMAND			ENDING
	PRO-DUCTION	IMPORT	NET FROM INVEN	TOTAL	DOMESTIC (MB/D)	DOMESTIC DEL %	EXPORT	INVENTORY (MMBBL)
1983	2456	174	124	2754	2690	1.1	64	140
1984	2681	272	(57)	2896	2845	5.8	51	161
1985	2687	200	48	2935	2868	0.8	67	144
1986	2798	247	(31)	3014	2914	1.6	100	155
1987	2731	255	56	3042	2976	2.1	66	134
1988	2859	302	30	3191	3122	4.9	69	124
1989	2899	306	49	3254	3157	1.1	97	106
1990	2925	277	(73)	3129	3020	(4.3)	109	132
1991	2910	212	1	3123	2953	(2.2)	170	132
1992	2864	255	(22)	3097	2997	1.5	100	140
1993	2857	275	0	3132	3042	1.5	90	140
1994	2894	275	(2)	3167	3087	1.5	80	141
1995	2929	275	(4)	3200	3132	1.5	70	143
1996	2942	300	(5)	3237	3179	1.5	60	145
1997	2955	325	(6)	3274	3226	1.5	50	147
1998	2959	350	12	3321	3273	1.5	50	143
1999	2950	275	0	3225	3177	(2.9)	50	143
2000	2954	275	(4)	3225	3177	0.0	50	145
2005	3014	400	(5)	3409	3361	1.2	50	154
2010	3074	525	(5)	3594	3545	1.2	50	163

Table A-8

U.S.
RESIDUAL FUEL OIL SUPPLY/DEMAND
(MB/D)

	SUPPLY				DEMAND			ENDING
	PRO-		NET FROM		DOMESTIC			INVENTORY
	DUCTION	IMPORT	INVEN	TOTAL	(MB/D)	DEL %	EXPORT	(MMBBL)
1983	852	699	55	1606	1421	(14.8)	185	49
1984	890	681	(12)	1559	1369	(3.7)	190	53
1985	882	510	7	1399	1202	(12.2)	197	50
1986	888	669	8	1565	1418	18.0	147	47
1987	885	565	0	1450	1264	(10.9)	186	47
1988	926	644	8	1578	1378	9.0	200	45
1989	954	629	2	1585	1370	(0.6)	215	44
1990	945	504	(13)	1436	1225	(10.6)	211	49
1991	949	434	2	1385	1154	(5.8)	231	48
1992	988	400	3	1391	1166	1.0	225	47
1993	968	420	5	1393	1168	0.2	225	45
1994	971	420	3	1394	1171	0.3	225	43
1995	979	420	0	1399	1174	0.3	225	43
1996	981	420	0	1401	1176	0.2	225	43
1997	984	420	1	1405	1179	0.3	225	44
1998	986	420	0	1406	1182	0.3	225	43
1999	976	400	0	1376	1171	(0.9)	220	43
2000	976	400	0	1376	1171	0.0	220	43
2005	995	430	(5)	1420	1185	0.3	225	45
2010	1014	430	(5)	1439	1199	0.3	250	47

Table A-9

WORLD PETROLEUM SUPPLY AND DEMAND
(MMB/D)

	DEMAND			SUPPLY							
	OECD	NON-OECD	TOTAL	OPEC CRUDE	NON-OPEC CRUDE	TOTAL CRUDE	TOTAL NGL'S	GAIN & OTHER	TOTAL NON-CRUDE	TOTAL SUPPLY	STOCK CHANGE
1983	33.79	25.03	58.82	17.89	35.08	52.97	3.92	1.21	5.13	58.10	(0.72)
1984	34.50	25.88	60.38	17.86	36.35	54.20	4.15	1.34	5.49	59.69	(0.69)
1985	34.27	25.86	60.13	16.63	37.01	53.65	4.21	1.40	5.62	59.26	(0.86)
1986	35.28	26.55	61.83	18.73	37.14	55.87	4.42	1.44	5.86	61.74	(0.09)
1987	35.91	26.80	62.71	18.85	37.46	56.31	4.56	1.50	6.07	62.37	(0.34)
1988	37.09	27.30	64.39	20.79	37.72	58.51	4.62	1.45	6.07	64.58	0.19
1989	37.56	27.98	65.53	22.36	36.57	58.93	5.07	1.48	6.55	65.48	(0.05)
1990	37.52	27.97	65.50	23.35	36.00	59.35	5.17	1.49	6.66	66.00	0.51
1991	37.80	28.25	66.04	23.56	35.88	59.44	5.31	1.48	6.79	66.23	0.19
1992	38.25	28.87	67.12	24.32	35.97	60.29	5.38	1.49	6.88	67.14	0.02
1993	38.80	29.85	68.65	25.64	36.05	61.69	5.58	1.53	7.11	68.66	0.01
1994	39.40	30.21	69.61	26.31	36.20	62.51	5.55	1.55	7.10	69.61	0.00
1995	39.94	30.69	70.63	26.94	36.47	63.41	5.66	1.56	7.22	70.63	0.00
1996	40.48	31.16	71.64	27.04	37.39	64.43	5.64	1.57	7.21	71.64	0.00
1997	41.02	31.64	72.66	27.83	37.39	65.22	5.83	1.61	7.44	72.66	0.00
1998	41.59	32.17	73.76	28.62	37.71	66.33	5.80	1.63	7.43	73.76	0.00
1999	40.82	31.58	72.40	28.10	37.50	65.60	5.50	1.59	7.09	72.62	0.22
2000	40.82	31.58	72.40	27.03	37.98	65.01	5.46	1.44	6.90	71.90	(0.49)
2005	43.10	33.97	77.07	30.61	38.59	69.20	6.16	1.71	7.87	77.07	0.00
2010	45.69	36.56	82.25	31.93	41.92	73.85	6.57	1.83	8.40	82.25	0.00

Table A-10

U.S. CRUDE OIL SUPPLY AND DEMAND

(MB/D)

	DEMAND						SUPPLY				ENDING INVENTORIES (MM BBL)	
	REFINERY RUNS	DIRECT TO FUEL	TO *SPR	EXPORTS	LOSS & UNACCNTD	TOTAL	TOTAL	DOMESTIC PROD'N	FROM INVEN	IMPORTS	COMM'L	SPR
1983	11685	66	0	164	(111)	11804	11804	8688	20	3096	344	379
1984	12044	64	(2)	181	(183)	12104	12104	8879	(4)	3229	345	451
1985	12002	60	(1)	204	(144)	12121	12121	8971	67	3083	319	493
1986	12716	49	2	154	(139)	12782	12782	8680	(28)	4130	331	512
1987	12854	34	7	151	(145)	12901	12901	8349	(49)	4601	349	541
1988	13246	40	0	155	(195)	13246	13246	8140	51	5055	330	560
1989	13401	28	0	142	(201)	13370	13370	7613	(30)	5787	341	580
1990	13409	24	0	113	(315)	13231	13231	7356	8	5867	323	586
1991	13350	19	0	121	(255)	13235	13234	7339	6	5889	338	568
1992	13322	15	0	90	(253)	13174	13174	7230	(11)	5955	342	578
1993	13262	10	0	85	(250)	13107	13107	7050	(30)	6087	353	587
1994	13391	5	0	80	(250)	13226	13226	6930	(2)	6298	354	596
1995	13416	0	0	80	(250)	13246	13246	6757	(10)	6499	358	605
1996	13550	0	0	80	(250)	13380	13380	6588	(10)	6802	361	614
1997	13604	0	0	80	(250)	13514	13514	6423	(9)	7100	364	623
1998	13802	0	0	80	(250)	13632	13632	6263	8	7361	361	632
1999	13692	0	0	80	(250)	13522	13522	6106	(2)	7418	362	642
2000	13721	0	0	80	(250)	13551	13551	5953	(5)	7603	364	651
2005	14087	0	0	80	(250)	13917	13917	5114	(11)	8814	376	696
2010	14462	0	0	80	(250)	14292	14292	4509	(10)	9793	388	740

* DOMESTIC CRUDE TO SPR

Table A-11

CRUDE OIL PRICES
($/B)
(CURRENT DOLLARS)

	U.S. INFLATION % PER YR	U.S. INFLATION GNP DFLTR	US AVG ACQ COST	SPOT WTI	OPEC BASKET	BRENT	DUBAI	MAYA (US)
1983	3.82	103.85	28.99	30.39		29.71	28.18	
1984	3.68	107.68	28.63	29.40		28.72	27.46	
1985	2.97	110.88	26.75	27.98		27.47	26.22	
1986	2.73	113.90	14.67	15.01		14.19	12.91	12.75
1987	3.09	117.43	17.88	19.13		18.39	16.88	12.67
1988	3.26	121.25	14.72	15.96		14.95	13.16	11.23
1989	4.69	126.30	17.96	19.64	17.35	18.15	15.64	14.69
1990	4.08	131.45	22.35	24.45	22.34	23.70	20.39	17.15
1991	3.50	136.05	19.55	21.68	18.29	20.23	16.72	12.85
1992	4.04	141.54	21.35	23.35	21.00	21.95	18.85	17.20
1993	4.49	147.90	22.70	24.75	22.35	23.30	20.15	18.35
1994	4.20	154.11	24.25	26.00	23.25	24.30	21.25	19.20
1995	4.00	160.28	25.10	27.00	24.00	25.20	22.00	19.70
1996	4.00	166.69	26.20	28.25	25.00	26.35	22.80	20.30
1997	4.60	174.35	28.25	30.50	27.00	28.45	24.75	21.80
1998	6.00	184.82	35.90	38.50	33.65	36.15	31.10	26.85
1999	5.00	194.06	30.60	33.00	29.20	30.70	25.85	22.95
2000	4.50	202.79	32.40	35.00	31.00	32.60	27.95	24.60
2005	4.00	246.72	41.75	45.00	39.85	42.10	35.50	30.45
2010	4.00	300.18	51.54	55.00	49.90	52.97	47.28	35.99

Table A-12

CRUDE OIL PRICES
($/B)
(CONSTANT 1990 DOLLARS)

	U.S. INFLATION							
	% PER YR	GNP DFLTR	US AVG ACQ COST	SPOT WTI	OPEC BASKET	BRENT	DUBAI	MAYA (US)
1983	3.82	103.85	36.70	38.47		37.61	35.67	
1984	3.68	107.68	34.95	35.89		35.06	33.52	
1985	2.97	110.88	31.71	33.17		32.56	31.09	
1986	2.73	113.90	16.93	17.32		16.38	14.90	14.71
1987	3.09	117.43	20.01	21.41		20.59	18.90	14.18
1988	3.26	121.25	15.96	17.30		16.20	14.27	12.17
1989	4.69	126.30	18.69	20.44	18.06	18.89	16.28	15.29
1990	4.08	131.45	22.35	24.45	22.34	23.70	20.39	17.15
1991	3.50	136.05	18.89	20.95	17.67	19.55	16.15	12.42
1992	4.04	141.54	19.83	21.69	19.50	20.39	17.51	15.97
1993	4.49	147.90	20.18	22.00	19.86	20.71	17.91	16.31
1994	4.20	154.11	20.68	22.18	19.83	20.73	18.13	16.38
1995	4.00	160.28	20.59	22.14	19.68	20.67	18.04	16.16
1996	4.00	166.69	20.66	22.28	19.72	20.78	17.98	16.01
1997	4.60	174.35	21.30	22.99	20.36	21.45	18.66	16.44
1998	6.00	184.82	25.53	27.38	23.93	25.71	22.12	19.10
1999	5.00	194.06	20.73	22.35	19.78	20.80	17.51	15.55
2000	4.50	202.79	21.00	22.69	20.09	21.13	18.12	15.95
2005	4.00	246.72	22.24	23.98	21.23	22.43	18.91	16.22
2010	4.00	300.18	22.57	24.08	21.85	23.20	20.71	15.76

Table A-13

CRUDE OIL PRICE SPREADS
($/B)
(CONSTANT 1990 DOLLARS)

	WTI VS US AVG ACQ COST	WTI VS OPEC BASKET	WTI VS BRENT	WTI VS DUBAI	BRENT VS DUBAI	MAYA (US) VS DUBAI
1983	1.77		0.86	2.80	1.94	
1984	0.94		0.83	2.37	1.54	
1985	1.46		0.61	2.09	1.48	
1986	0.40		0.94	2.42	1.48	(0.18)
1987	1.40		0.83	2.52	1.69	(4.71)
1988	1.34		1.10	3.04	1.94	(2.09)
1989	1.75	2.38	1.55	4.16	2.61	(0.99)
1990	2.10	2.11	0.75	4.06	3.31	(3.24)
1991	2.06	3.28	1.40	4.79	3.39	(3.74)
1992	1.86	2.18	1.30	4.18	2.88	(1.53)
1993	1.82	2.13	1.29	4.09	2.80	(1.60)
1994	1.49	2.35	1.45	4.05	2.60	(1.75)
1995	1.56	2.46	1.48	4.10	2.62	(1.89)
1996	1.62	2.56	1.50	4.30	2.80	(1.97)
1997	1.70	2.64	1.55	4.34	2.79	(2.22)
1998	1.85	3.45	1.67	5.26	3.59	(3.02)
1999	1.63	2.57	1.56	4.84	3.29	(1.96)
2000	1.69	2.59	1.56	4.57	3.01	(2.17)
2001	1.71	2.62	1.56	4.71	3.15	(2.31)
2002	1.71	2.67	1.56	4.91	3.36	(2.43)
2003	1.73	2.71	1.56	5.07	3.52	(2.48)
2004	1.72	2.72	1.55	5.07	3.52	(2.55)
2005	1.73	2.74	1.55	5.06	3.52	(2.69)
2006	1.52	2.72	1.50	4.82	3.32	(3.13)
2007	1.52	2.66	1.40	4.53	3.12	(3.57)
2008	1.52	2.55	1.27	4.19	2.92	(4.03)
2009	1.52	2.41	1.10	3.80	2.71	(4.48)
2010	1.52	2.23	0.89	3.38	2.49	(4.95)

Table A-14

SPOT U.S. REFINED PRODUCT PRICES
(¢/GAL)
(CURRENT DOLLARS)

	CRUDE ACQ COST	UNLD REG	UNLD MID	PREM UNLD	KERO JET	DIST	MTBE
1983	69.03	82.77		86.77	80.58	77.35	
1984	68.17	75.97		79.97	78.80	76.88	
1985	63.68	76.18		80.18	75.98	73.21	99.25
1986	34.92	43.18		48.80	44.35	41.30	65.33
1987	42.56	49.95		54.19	51.01	49.39	69.50
1988	35.05	47.05		54.34	46.09	42.99	81.67
1989	42.76	55.48		61.23	55.16	51.89	86.61
1990	53.21	70.34	72.78	76.29	72.31	65.33	112.53
1991	46.55	61.74	63.15	65.25	58.77	55.82	87.20
1992	50.83	67.31	69.31	71.81	64.44	62.06	102.80
1993	54.05	71.00	73.00	75.75	68.19	65.81	110.00
1994	57.74	76.00	78.22	81.30	72.53	69.39	120.00
1995	59.76	78.35	80.87	84.21	75.62	71.94	130.00
1996	62.38	81.99	84.80	88.16	79.30	75.59	132.00
1997	67.26	89.88	93.00	96.38	86.25	82.01	138.00
1998	85.48	117.12	121.80	127.20	112.55	106.01	171.00
1999	72.86	97.52	100.50	103.91	93.50	88.93	141.00
2000	77.14	101.82	105.10	109.02	99.85	94.24	150.00
2001	80.95	108.64	112.21	116.89	104.71	99.08	158.00
2002	86.07	115.77	119.62	124.57	111.87	105.22	168.00
2003	90.48	122.19	126.57	131.79	117.82	110.65	176.00
2004	95.00	128.72	133.39	138.86	124.89	116.20	186.00
2005	99.40	135.14	140.09	145.82	131.34	122.12	194.00
2006	104.86	142.60	147.83	153.58	137.83	127.84	202.00
2007	109.31	149.06	154.57	160.33	144.32	132.82	209.00
2008	113.79	155.55	161.34	167.10	150.84	138.06	219.00
2009	118.24	162.01	168.08	174.10	157.33	143.03	227.00
2010	122.71	168.50	174.84	180.87	163.84	148.28	235.00

Table A-15

SPOT U.S. REFINED PRODUCT PRICES
(¢/GAL)
(CONSTANT 1990 DOLLARS)

	CRUDE ACQ COST	UNLD REG	UNLD MID	PREM UNLD	KERO JET	DIST	MTBE
1983	87.38	104.77		109.83	102.00	97.91	
1984	83.22	92.74		97.63	96.20	93.86	
1985	75.50	90.32		95.06	90.08	86.80	117.67
1986	40.30	49.83		56.32	51.18	47.66	75.40
1987	47.64	55.91		60.66	57.10	55.29	77.80
1988	38.00	51.01		58.91	49.97	46.61	88.54
1989	44.51	57.74		63.73	57.41	54.01	90.14
1990	53.21	70.34	72.78	76.29	72.31	65.33	112.53
1991	44.97	59.65	61.01	63.04	56.78	53.93	84.25
1992	47.21	62.51	64.37	66.69	59.85	57.64	95.47
1993	48.04	63.10	64.88	67.32	60.61	58.49	97.77
1994	49.25	64.83	66.72	69.34	61.87	59.18	102.36
1995	49.01	64.26	66.33	69.06	62.02	59.00	106.62
1996	49.19	64.65	66.88	69.52	62.54	59.61	104.09
1997	50.71	67.77	70.12	72.66	65.03	61.83	104.04
1998	60.79	83.30	86.63	90.47	80.05	75.40	121.62
1999	49.35	66.06	68.08	70.39	63.34	60.24	95.51
2000	50.00	66.00	68.12	70.67	64.72	61.09	97.23
2001	50.46	67.71	69.94	72.86	65.26	61.75	98.48
2002	51.58	69.38	71.69	74.66	67.05	63.06	100.68
2003	52.14	70.41	72.94	75.94	67.90	63.76	101.42
2004	52.64	71.32	73.91	76.94	69.20	64.38	103.06
2005	52.96	72.00	74.64	77.69	69.98	65.07	103.36
2006	53.72	73.05	75.73	78.68	70.61	65.49	103.48
2007	53.84	73.43	76.14	78.97	71.09	65.42	102.95
2008	53.89	73.67	76.42	79.15	71.44	65.39	103.73
2009	53.85	73.78	76.55	79.29	71.65	65.14	103.38
2010	53.74	73.78	76.56	79.20	71.75	64.93	102.91

Table A-16

SPOT FUEL OIL PRICES

($/BBL)

CURRENT $

	U.S. INFLATION				GULF COAST		NEW YORK		CARIBBEAN
	% PER YR	GNP DFLTR	US AVG ACQ COST	DUBAI	0.7% S LSFO	3.0% S HSFO	0.3% S LSFO	3.0% S HSFO	2.8% S HSFO
1983	3.82	103.85	24.10	28.18	26.39	24.23	29.69	25.28	24.10
1984	3.68	107.68	26.40	27.46	27.90	26.32	30.52	27.37	26.40
1985	2.97	110.88	22.46	26.22	24.04	22.39	27.95	23.35	22.46
1986	2.73	113.90	11.17	12.91	13.52	11.21	15.47	12.10	11.17
1987	3.09	117.43	15.34	16.88	17.31	15.27	19.32	16.10	15.34
1988	3.26	121.25	10.51	13.16	13.82	10.50	15.67	11.33	10.51
1989	4.69	126.30	13.30	15.64	17.19	13.34	18.93	14.33	13.30
1990	4.08	131.45	14.80	20.39	19.84	14.46	23.17	15.82	14.80
1991	3.50	136.05	11.41	16.72	14.62	10.14	17.58	11.04	11.41
1992	4.04	141.54	15.69	18.85	16.89	12.64	19.32	13.72	15.69
1993	4.49	147.90	16.75	20.15	19.50	15.20	22.05	16.25	16.75
1994	4.20	154.11	16.45	21.25	21.00	16.40	23.54	17.49	16.45
1995	4.00	160.28	16.95	22.00	21.90	16.90	24.74	18.04	16.95
1996	4.00	166.69	17.51	22.80	22.90	17.45	25.98	18.63	17.51
1997	4.60	174.35	18.86	24.75	24.90	18.80	28.04	20.04	18.86
1998	6.00	184.82	23.41	31.10	30.60	23.35	34.68	24.68	23.41
1999	5.00	194.06	19.92	25.85	25.95	19.85	30.01	21.26	19.92
2000	4.50	202.79	21.92	27.95	28.50	21.85	32.87	23.32	21.92
2001	4.00	210.90	23.07	29.20	30.15	23.00	34.88	24.53	23.07
2002	4.00	219.34	24.58	30.80	32.20	24.50	37.24	26.09	24.58
2003	4.00	228.11	25.58	32.20	33.75	25.50	39.10	27.15	25.58
2004	4.00	237.24	26.93	33.85	35.60	26.85	41.32	28.57	26.93
2005	4.00	246.72	28.39	35.50	37.55	28.30	43.59	30.09	28.39
2006	4.00	256.59	30.39	37.59	40.04	30.29	45.90	32.15	30.39
2007	4.00	266.86	32.41	39.81	42.56	32.31	48.28	34.23	32.41
2008	4.00	277.53	34.56	42.16	45.21	34.46	50.75	36.45	34.56
2009	4.00	288.63	36.51	44.65	47.65	36.40	53.11	38.46	36.51
2010	4.00	300.18	37.50	47.28	49.74	37.38	54.46	39.51	37.50

Table A-17

SPOT FUEL OIL PRICES

($/BBL)

CONSTANT 1990$

	U.S. INFLATION				GULF COAST		NEW YORK		CARIBBEAN
	% PER YR	GNP DFLTR	US AVG ACQ COST	DUBAI	0.7% S LSFO	3.0% S HSFO	0.3% S LSFO	3.0% S HSFO	2.8% S HSFO
1983	3.82	103.85	36.70	35.67	33.41	30.67	37.58	32.00	30.51
1984	3.68	107.68	34.95	33.52	34.06	32.13	37.26	33.41	32.23
1985	2.97	110.88	31.71	31.09	28.50	26.54	33.14	27.68	26.63
1986	2.73	113.90	16.93	14.90	15.61	12.94	17.85	13.96	12.89
1987	3.09	117.43	20.01	18.90	19.38	17.09	21.62	18.03	17.17
1988	3.26	121.25	15.96	14.27	14.98	11.39	16.98	12.29	11.39
1989	4.69	126.30	18.69	16.28	17.89	13.88	19.70	14.91	13.84
1990	4.08	131.45	22.35	20.39	19.84	14.46	23.17	15.82	14.80
1991	3.50	136.05	18.89	16.15	14.13	9.80	16.99	10.67	11.02
1992	4.04	141.54	19.83	17.51	15.69	11.74	17.94	12.74	14.57
1993	4.49	147.90	20.18	17.91	17.33	13.51	19.60	14.44	14.89
1994	4.20	154.11	20.68	18.13	17.91	13.99	20.08	14.92	14.03
1995	4.00	160.28	20.59	18.04	17.96	13.86	20.29	14.79	13.90
1996	4.00	166.69	20.66	17.98	18.06	13.76	20.49	14.69	13.81
1997	4.60	174.35	21.30	18.66	18.77	14.17	21.14	15.11	14.22
1998	6.00	184.82	25.53	22.12	21.76	16.61	24.66	17.55	16.65
1999	5.00	194.06	20.73	17.51	17.58	13.45	20.33	14.40	13.49
2000	4.50	202.79	21.00	18.12	18.47	14.16	21.31	15.12	14.21
2001	4.00	210.90	21.19	18.20	18.79	14.34	21.74	15.29	14.38
2002	4.00	219.34	21.66	18.46	19.30	14.68	22.32	15.64	14.73
2003	4.00	228.11	21.90	18.56	19.45	14.69	22.53	15.65	14.74
2004	4.00	237.24	22.11	18.76	19.73	14.88	22.89	15.83	14.92
2005	4.00	246.72	22.24	18.91	20.01	15.08	23.22	16.03	15.12
2006	4.00	256.59	22.56	19.26	20.51	15.52	23.51	16.47	15.57
2007	4.00	266.86	22.61	19.61	20.96	15.92	23.78	16.86	15.96
2008	4.00	277.53	22.64	19.97	21.41	16.32	24.04	17.26	16.37
2009	4.00	288.63	22.62	20.33	21.70	16.58	24.19	17.52	16.63
2010	4.00	300.18	22.57	20.70	21.78	16.37	23.85	17.30	16.42

Table A-18

SPOT FUEL OIL SPREADS

($/BBL)

CONSTANT 1990$

	GC HSFO VS DUBAI	GC HSFO VS US AVG ACQ COST	GC LSFO VS US AVG ACQ COST	GC LSFO VS HSFO	NY LSFO VS HSFO
1983	(5.00)	(6.03)	(3.29)	2.74	5.58
1984	(1.40)	(2.83)	(0.89)	1.94	3.85
1985	(4.54)	(5.17)	(3.21)	1.96	5.46
1986	(1.96)	(3.99)	(1.32)	2.66	3.89
1987	(1.81)	(2.92)	(0.63)	2.29	3.60
1988	(2.88)	(4.57)	(0.98)	3.60	4.70
1989	(2.40)	(4.81)	(0.80)	4.01	4.79
1990	(5.93)	(7.89)	(2.51)	5.38	7.35
1991	(6.36)	(9.09)	(4.76)	4.33	6.32
1992	(5.77)	(8.09)	(4.14)	3.95	5.20
1993	(4.40)	(6.67)	(2.84)	3.82	5.15
1994	(4.14)	(6.70)	(2.77)	3.92	5.16
1995	(4.18)	(6.73)	(2.62)	4.10	5.49
1996	(4.22)	(6.90)	(2.60)	4.30	5.80
1997	(4.49)	(7.12)	(2.53)	4.60	6.03
1998	(5.51)	(8.93)	(3.77)	5.16	7.11
1999	(4.06)	(7.28)	(3.15)	4.13	5.93
2000	(3.95)	(6.84)	(2.53)	4.31	6.19
2001	(3.86)	(6.86)	(2.40)	4.46	6.45
2002	(3.78)	(6.98)	(2.37)	4.61	6.68
2003	(3.86)	(7.20)	(2.45)	4.75	6.89
2004	(3.88)	(7.23)	(2.38)	4.85	7.06
2005	(3.84)	(7.17)	(2.24)	4.93	7.19
2006	(3.74)	(7.04)	(2.05)	4.99	7.04
2007	(3.69)	(6.70)	(1.65)	5.05	6.92
2008	(3.65)	(6.31)	(1.22)	5.09	6.77
2009	(3.76)	(6.04)	(0.92)	5.12	6.67
2010	(4.34)	(6.20)	(0.79)	5.41	6.55

Table A-19

SPOT U.S. REFINED PRODUCT PRICES
RATIO TO CRUDE
(CONSTANT 1990 DOLLARS)

	UNLD REG	UNLD MID	PREM UNLD	KERO JET	DIST	MTBE
1983	1.20		1.26	1.17	1.12	
1984	1.11		1.17	1.16	1.13	
1985	1.20		1.26	1.19	1.15	1.56
1986	1.24		1.40	1.27	1.18	1.87
1987	1.17		1.27	1.20	1.16	1.63
1988	1.34		1.55	1.32	1.23	2.33
1989	1.30		1.43	1.29	1.21	2.03
1990	1.32	1.37	1.43	1.36	1.23	2.11
1991	1.33	1.36	1.40	1.26	1.20	1.87
1992	1.32	1.36	1.41	1.27	1.22	2.02
1993	1.31	1.35	1.40	1.26	1.22	2.04
1994	1.32	1.35	1.41	1.26	1.20	2.08
1995	1.31	1.35	1.41	1.27	1.20	2.18
1996	1.31	1.36	1.41	1.27	1.21	2.12
1997	1.34	1.38	1.43	1.28	1.22	2.05
1998	1.37	1.43	1.49	1.32	1.24	2.00
1999	1.34	1.38	1.43	1.28	1.22	1.94
2000	1.32	1.36	1.41	1.29	1.22	1.94
2001	1.34	1.39	1.44	1.29	1.22	1.95
2002	1.35	1.39	1.45	1.30	1.22	1.95
2003	1.35	1.40	1.46	1.30	1.22	1.95
2004	1.35	1.40	1.46	1.31	1.22	1.96
2005	1.36	1.41	1.47	1.32	1.23	1.95
2006	1.36	1.41	1.46	1.31	1.22	1.93
2007	1.36	1.41	1.47	1.32	1.22	1.91
2008	1.37	1.42	1.47	1.33	1.21	1.92
2009	1.37	1.42	1.47	1.33	1.21	1.92
2010	1.37	1.42	1.47	1.34	1.21	1.92

Table A-20

SPOT U.S. REFINED PRODUCT PRICE SPREADS (CONSTANT 1990 DOLLARS)

	UNLD/ CRUDE AAC $/BBL	MID VS REG	PREM VS REG	KERO–JET VS DIST	DIST/ CRUDE AAC $/BBL	MTBE VS UNLD	GULF COAST CASH MARGIN $/BBL
1983	7.30		5.06	4.09	4.42		1.86
1984	4.00		4.88	2.34	4.47		0.46
1985	6.22		4.74	3.28	4.74	27.35	1.35
1986	4.00		6.49	3.52	3.09	25.56	1.33
1987	3.47		4.75	1.81	3.21	21.88	0.40
1988	5.47		7.90	3.36	3.62	37.53	2.38
1989	5.56		5.98	3.40	3.99	32.40	2.04
1990	7.19	2.44	5.95	6.98	5.09	42.19	3.16
1991	6.17	1.36	3.39	2.85	3.76	24.60	2.92
1992	6.43	1.86	4.18	2.21	4.38	32.96	2.24
1993	6.33	1.78	4.22	2.12	4.39	34.66	2.22
1994	6.54	1.89	4.52	2.68	4.17	37.53	2.19
1995	6.40	2.07	4.81	3.02	4.20	42.36	2.18
1996	6.49	2.22	4.87	2.93	4.38	39.44	2.29
1997	7.16	2.35	4.89	3.20	4.67	36.28	2.73
1998	9.45	3.33	7.17	4.65	6.14	38.32	4.17
1999	7.02	2.02	4.33	3.10	4.57	29.45	2.51
2000	6.72	2.12	4.67	3.63	4.66	31.23	2.40
2001	7.25	2.22	5.14	3.51	4.75	30.76	2.72
2002	7.48	2.31	5.27	3.99	4.82	31.30	2.79
2003	7.68	2.53	5.53	4.13	4.88	31.01	2.92
2004	7.85	2.59	5.62	4.82	4.93	31.74	3.06
2005	8.00	2.64	5.69	4.91	5.08	31.36	3.18
2006	8.12	2.68	5.62	5.12	4.95	30.43	3.18
2007	8.22	2.71	5.55	5.67	4.86	29.52	3.23
2008	8.31	2.74	5.47	6.05	4.83	30.05	3.28
2009	8.37	2.76	5.51	6.51	4.74	29.60	3.32
2010	8.42	2.78	5.42	6.81	4.70	29.12	3.35

Table A-21

SECTION 2

THE U.S. CLEAN AIR ACT AMENDMENTS OF 1990

The **Clean Air Act Amendments of 1990** is one of the best examples in recent history of how the forces of government and environment can be all-consuming. Without a doubt, the Clean Air Act of 1990 will change all of our lives.

OVERVIEW

It is important to understand that the U.S. Congressional actions and EPA mandates have been undergoing careful consideration for many years. The anticipated environmental impact should benefit all of us in the form of substantially reduced amounts of air pollution. At a projected cost of less than 5¢ per gallon, the public should gain measurably cleaner air. The emission of volatile organic compounds (VOCs) by gasoline-powered vehicles should fall by 15%, beginning in 1995, in covered ozone non-attainment areas. Also, mass toxic emissions should fall by at least 30% in covered areas. Cases of cancer associated with these types of toxic emissions are projected to be reduced by 25-33%.

The Clean Air Act was signed into law on November 15, 1990, and sets guidelines for air pollution control which impact those who *make* fuel, as well as those who *use* it, or who manufacture products which use it. It mandates guidelines for specific actions and standards, as well as a continued **pro-active** study to be undertaken by Congress in the coming years to continue the pursuit of minimizing air pollution. Committees are to evaluate the harmful effects upon our environment of various fuel components and/or emissions such as benzene, formaldehyde, and 1,3 butadiene. Such studies are to begin within 18 months of the Act, and acted upon within 54 months.

One unique aspect of this Act is the mandate for continual evaluation and review of our air quality and the elements which we put into it.

Oxygenated Gasoline Required in 1992

There are 41 areas in the country whose levels of **airborne carbon monoxide** are gauged to be in excess of 9.5 parts per million (ppm). By the Clean Air Act's guidelines, this is the threshold which indicates excessive amounts of CO.

Effective November 1, 1992, it is required that all gasolines sold within these areas be **oxygenated**, or to contain 2.7% oxygen by weight **during the times of the year where, in the judgment of the EPA, the areas are prone to high ambient concentrations of carbon monoxide.** Most of the cities will have a four-month control period, November through February. The EPA is proposing longer control periods for the five worst areas. The length of the period will match the length of the CO pollution season. Bonner & Moore estimates that as a base-case scenario, well over 16% of the total U.S. gasoline pool will need to be oxygenated in order to meet this requirement for the years 1992 through 1994.

The 2.7% requirement is not without controversy. Many refiners will be handcuffed without the redefinition of what constitutes product which is substantially similar to unleaded gasoline, because previous restrictions on substantially similar product would have made oxygenates use in unleaded gasoline illegal.

Early in 1991, the EPA was asked to broaden its meaning of **substantially similar** product -- meaning, what product it would consider to be acceptably comparable to currently marketed unleaded gasoline, so as not to require the submission of a separate waiver. Although the Clean Air Act does not define **substantially similar**, the EPA has recently commented on it. Effective immediately, "...the allowable oxygen content for a substantially similar unleaded gasoline is increased from 2.0% (max.) by weight to 2.7% (max.) by weight, for blends of aliphatic alcohols and/or ethers, excluding methanol." It was further noted that, "unleaded gasolines containing up to 2.7% oxygen by weight...exhibit no major differences from vehicle certification fuel with respect to driveability or materials compatibility." It is important to note that the EPA is not changing the breadth of the permitted aliphatic ethers -- only the total oxygen content. This move is a relief to refiners and blenders because it promotes greater flexibility in meeting governmental regulations on required levels of oxygen content in gasoline.

For the sake of clarity, the following definition of **substantially similar** is provided by the Environmental Protection Agency:

Substantially Similar

EPA will treat a fuel or fuel additive for general use in light-duty vehicles manufactured after model year 1974 as **substantially similar** to any fuel or fuel additive utilized in the certification of any model year 1975, or subsequent model year vehicle or engine, under section 206 of the Act; i.e., **substantially similar**, if the following criteria are met.

(1) The fuel must contain carbon, hydrogen, and oxygen, nitrogen, and/or sulfur, exclusively,[1] in the form of some combination of the following:

- (a) hydrocarbons
- (b) aliphatic ethers
- (c) aliphatic alcohols other than methanol
- (d) (i) up to 0.3% methanol by volume
  - (ii) up to 2.75% methanol by volume with an equal volume of butanol, or higher molecular weight alcohol
- (e) a fuel additive[2] at a concentration of no more than 0.25% by weight which contributes no more than 15 ppm sulfur by weight to the fuel.

(2) The fuel must contain no more than 2.0% oxygen by weight, except fuels containing aliphatic ethers and/or alcohols (excluding methanol) must contain no more than 2.7% oxygen by weight.

[1] Impurities which produce gaseous combustion products (i.e., products which exist as a gas at Standard Temperature and Pressure) may be present in the fuel at trace levels. An impurity is that substance which is present through contamination, or remains naturally, after processing of the fuel is completed.

[2] For the purposes of this interpretive rule, the term "fuel additive" refers only to that part of the additive package which is not hydrocarbon.

(3) The fuel must possess, at the time of manufacture, all of the physical and chemical characteristics of an unleaded gasoline as specified in ASTM Standard D 4814-88 for at least one of the Seasonal and Geographical Volatility Classes specified in the standard.

(4) The fuel additive must contain only carbon, hydrogen, and any one or all of the following elements: oxygen, nitrogen, and/or sulfur.[3]

Reformulated Gasoline Steps to Center Stage

It has long been accepted that a reformulated gasoline blend which includes oxygenates will make a marked reduction in overall levels of air pollution. Several major gasoline marketers have already introduced reformulated gasoline products. In order to avoid confusion on the subject, the EPA must prescribe what **reformulated gasoline is, and what it is not**.

Through an extended regulatory negotiation process and comment period, the EPA was able to reach an agreement on proposed reformulated gasoline regulations. These requirements include the product specifications and performance standards which must be met in order for gasoline to be certified as reformulated. Also, the EPA defines the process whereby gasolines can receive certification. A program for granting tradeable credits to fuel producers that certify reformulated gasoline that is less-polluting than required will be spelled out. The EPA is also required to establish the provisions implementing the prohibition of selling conventional gasoline that is dirtier than it was in 1990.

It was agreed to use a "simple model" for reformulated gasoline certification initially, until May 1997. The EPA is to issue a Notice of Proposed Rulemaking on a "complex model" for reformulated gasoline certification by the end of November 1992. A final rule is to be issued by May 1993 for use in certification of products produced on or after March 1997.

The EPA has until November 15, 1991, to define the exact requirements of reformulated gasoline. Those requirements will include the product specifications and performance standards which must be met in order for gasoline to be certified as reformulated. Also, the EPA will define the process whereby gasolines can receive certification. A program for granting tradeable credits to fuel producers that certify reformulated gasoline that is less-polluting than required will be spelled-out. The EPA is also required to establish the provisions implementing the prohibition of selling conventional gasoline that is dirtier than it was in 1990.

Section 211(k) of the Act, as amended, prohibits gasoline that the EPA has not certified as reformulated from being sold to consumers in the nine large cities which experienced the worst levels of ozone pollution between 1987 and 1989; i.e., Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York, Philadelphia, and San Diego. Any other ozone non-attainment area may "opt-in" to have the prohibition applied to gasoline sold within its borders at the request of the governor of the state in which it is located. Furthermore, conventional gasoline sold elsewhere may not be more polluting than it was in 1990. The prohibitions take effect beginning January 1, 1995; however, a later effective date may be provided by the EPA in the case of the **opt-in areas**, where it is determined that the availability of some necessary fuel additives are in too little supply.

[3]Impurities which produce gaseous combustion products may be present in the fuel additive at trace levels.

In order to establish a common basis for comparison of gasolines, the EPA set up guidelines for what they refer to as **Baseline Gasoline**. The EPA has also created the term **Baseline Vehicles**. These are simply representative 1990 model year vehicles, selected by the agency for the creation of a standard basis of comparison, for the purpose of measuring air emissions -- either through the tailpipes or by way of evaporation.

Baseline Gasoline

Baseline Gasoline has summertime specifications and wintertime specifications. The **summertime specifications** are applicable in the case of gasoline sold during the high ozone period (as defined by the EPA) and are as follows:

BASELINE GASOLINE FUEL PROPERTIES
(Summertime Specs)

API Gravity	57.4
Sulfur, ppm	339
Benzene, %	1.53
RVP, psi	8.7
Octane, R+M/2	87.3
IBP, °F	91
10%, °F	128
50%, °F	218
90%, °F	330
EP, °F	415
Aromatics, %	32
Olefins, %	9.2
Saturates, %	58.8

The EPA has yet to establish the **wintertime specifications**. The wintertime specs of baseline gasoline are for gasoline sold at times other than the high ozone period (as defined by the EPA). These specifications shall be the specs of 1990 industry average gasoline sold during such period. No marketers of gasoline may sell products which are more polluting than their own marketed products, in the aggregate, from the year 1990. If such data is not available, the baseline gasoline specifications will be used, for the corresponding period.

The following summarizes the **reformulated gasoline property mandates** as established by the Clean Air Act and the Environmental Protection Agency. All qualitative mandates become law **effective January 1, 1995**.

(A) The **emissions of Nitrogen Oxide** (NOx) from baseline vehicles when burning reformulated gasoline shall be no greater than the nitrogen oxide emissions by the baseline vehicles when burning baseline gasoline. If the EPA determines that compliance with the limitation on emissions of nitrogen oxides under the preceding sentence is technically infeasible, considering the other requirements applicable under the section to such gasoline, the EPA may, as appropriate to ensure compliance with this subparagraph, adjust (or waive entirely), any other requirements of this paragraph (including the oxygen content requirement).

(B) The **oxygen content** shall equal or exceed 2% by weight, but may not exceed 2.7%. (This requirement may be waived, by the EPA, in whole or in part, for any ozone non-attainment area upon a determination by the EPA that compliance with such requirement would prevent or interfere with the attainment by the area of a national primary ambient air quality standard.)

(C) The **benzene content** of the reformulated gasoline shall not exceed 1%, by volume.

(D) The **reformulated gasoline shall contain no heavy metals**, including lead and manganese. (This requirement may be waived, by the EPA, if it is determined that addition of the heavy metal to the product will not increase, on an aggregate mass or cancer-risk basis, toxic air pollutant emissions from motor vehicles. However, **lead is specifically excluded** under any circumstance.)

(E) The **total aromatic hydrocarbon content** shall not exceed 25%, by volume.

(F) **Additives** must be included, to prevent the accumulation of deposits in engines or vehicle fuel supply systems. The EPA is to establish specifications for such additives by November 15, 1992, which are mostly aimed at the setting of performance standards.

(G) The aggregate mass emissions of VOCs and of toxins that result from the use of reformulated gasoline must:

(a) Be 15% below the level of such emissions that result from use of the baseline gasoline, increasing to a 25% decrease by the year 2000

(b) Not exceed the level of such emissions that result from use of a gasoline meeting the content specifications listed above as well as having an aromatic hydrocarbon content of no more than 25% by volume, whichever achieves greater reductions. The required emission reductions for VOCs and toxins are to be determined separately.

Regulatory Negotiation Underlying Issues

EPA has identified the following issues to be resolved through regulatory negotiation in developing the complex reformulated gasoline regulations:

(a) While the composition of the **baseline summer gasoline** is defined in section 211(k), the determinations of the baseline wintertime gasoline is left to the Agency. What studies could and should be undertaken or used as a basis for determining the composition of baseline wintertime gasoline?

(b) Section 211(k) defines baseline summer gasoline as having a Reid Vapor Pressure (RVP) level of 8.7 psi. However, summer RVP levels in Class B areas are expected to be 7.5 psi. Should the reformulated gasoline requirements take account of this difference in such a way as to ensure equivalent environmental benefits in all covered areas?

(c) The emission performance of several gasolines must be determined to develop emission performance requirements. That is, the requirements applicable to reformulated gasoline and conventional gasoline as of 1995 depend on the emission performance of the summer and winter baseline fuels, the specified "formula" fuel, and the 1990 fuels of individual refiners, blenders and importers. May any of the relevant emission performance levels be estimated by modelling or must emission testing be performed?

(d) What is the effect of various oxygenates on NOx emissions and what other fuel compositional changes can mitigate or eliminate this effect?

(e) What vehicle emission test procedures are appropriate for certifying fuels?

(f) Are sufficient data available to develop an emission model for certifying fuels without vehicle testing? If so, how many parameters must be included in the model? How should the model be updated in light of additional data that will become available in the future?

(g) How should the term "slate of fuels" be defined for certification purposes? What is the significance of the use of this term?

(h) What data are necessary and available for determining baseline emission limits for individual refiners, blenders and importers for purposes of the anti-dumping provisions of section 211(k)? In cases where data are available on some but not all fuel parameters, must the baseline fuel parameters be used in their entirety or only those needed to fill the gaps not filled by the data?

(i) What is the appropriate basis for granting credits -- mass/volume (i.e., for oxygen and benzene contents) or emissions performance (as would likely have to be the case for aromatics) or both?

(j) If credits for oxygen content are based on emissions performance, would they be based on weight percent oxygen only or must a different credit amount be developed for each oxygenate?

(k) What is the appropriate baseline for determining the amount of any credits earned--the requirements established by section 211(k) for benzene, oxygen and aromatics or the amount of those constituents in reformulated gasoline that would have occurred in the absence of a credit program?

(l) Over what time period may credits be traded? Is banking of credits allowed?

(m) What enforcement scheme will provide fuel producers the flexibility intended by Congress, while providing adequate assurance of compliance?

Related Issues

Credits may accrue for exceeding minimum oxygen content specifications. These credits may be applied to off-spec product, which may then be marketed for the same non-attainment area. Credit-related issues which must be addressed include the structure of the program, the time period over which the credits can be taken, the extent to which credits can be banked (if at all), self-reporting and self-auditing requirements, state enforcement, and auditing.

Areas which are not covered under the non-attainment guidelines may **opt-in**; i.e., they may elect to participate in the reduction of overall air pollution. This opting-in shall be done by the governor of each state, who then is responsible for communicating such intentions with the EPA. There may be participation delays, at the EPA's discretion, depending upon the supply of oxygenates.

Anti-dumping rules, which prohibit the sale of excessively polluting product in relatively cleaner markets, are also set forth. The main way in which the EPA addressed this issue was by stating that no marketer's product pool, in the aggregate, may be more polluting than it was in 1990.

IMPACTS OF THE CLEAN AIR ACT ON U.S. MTBE DEMAND

We view the CAA's requirements for fuel oxygenates as being divided into two phases. Phase I becomes effective November 1, 1992 and requires motor gasoline in all carbon monoxide (CO) non-attainment areas (presently 41 cities) to maintain an oxygen content of 2.7% weight percent during the four (4) winter months of November through February. Phase II of the CAA becomes effective January 1, 1995. This latter phase will require all severe ozone non-attainment areas (presently 9 major metropolitan areas) to market oxygenated gasoline with a minimum oxygen content of 2.0% weight percent each month of the year.

Bonner & Moore has concluded that Phase I will require 16% of the U.S. gasoline pool to contain oxygenates (at the 2.7% level). This study also concludes that when severe ozone non-attainment areas have to comply with the law in 1995, 35% of the U.S. gasoline pool will require oxygenates.

In our evaluation of 3 separate cases, we have chosen the requirements just outlined (which will ultimately affect 35% of the gasoline pool) as our base case scenario (also our low case). This 35% base case is our standard set of assumptions used for the remainder of this study. We have included our other two cases in this section to demonstrate the other possible scenarios considered. The other sections of this report, however, will use only this base case to derive U.S. MTBE and methanol supply/demand balances (**Table A-22**).

The results of this study illustrate that the U.S. MTBE requirements for the base case should surge in 1995 to 16,679 M tons/year. Based on current MTBE production and plans announced to date, we have concluded that the U.S. average-year MTBE capacity in 1995 will stand at 15,225 M tons/year. Our base case requirement for MTBE of 16,679 M tons/year, less production of 13,040 M tons from existing and expected capacity, will result in a 3,640 M tons shortfall. As a result, we're calling for MTBE imports to reach 3,640 M tons in 1995, then trail off thereafter (as other oxygenates are added to the pool) to around 3,000 M tons/year. In summary, our base case projection regarding MTBE requirements calls for the following:

U.S. BUTANE REQUIREMENTS RESULTING FROM CAA OXYGENATE DEMAND

YEAR	SIZE OF GASOLINE POOL M bpd	% OF POOL REQUIRING OXYGENTATES BASE CASE Percent	MEDIUM CASE Percent	HIGH CASE Percent	MTBE REQUIREMENTS* BASE CASE M bpd	MEDIUM CASE M bpd	HIGH CASE M bpd	NORMAL BUTANE REQUIRMENTS* BASE CASE M bpd	MEDIUM CASE M bpd	HIGH CASE M bpd	ISOBUTANE REQUIREMENTS* BASE CASE M bpd	MEDIUM CASE M bpd	HIGH CASE M bpd
1991	7,274	0.0%	0.0%	0.0%	95	95	95	15	15	15	25	25	25
1992	7,334	8.0%	8.0%	8.0%	148	144	144	43	42	42	54	52	52
1993	7,490	16.0%	16.0%	16.0%	185	181	181	39	38	38	61	59	59
1994	7,545	16.0%	16.0%	16.0%	179	156	156	58	50	50	68	59	59
1995	7,590	35.0%	43.0%	60.0%	339	384	548	127	151	198	139	163	211
1996	7,550	35.0%	43.0%	60.0%	329	366	506	126	150	198	138	162	210
1997	7,490	35.0%	43.0%	60.0%	326	363	501	126	150	198	138	162	210
1998	7,475	35.0%	43.0%	60.0%	325	362	500	126	150	198	138	162	210
1999	7,485	35.0%	43.0%	60.0%	326	362	500	125	149	197	137	161	209
2000	7,515	35.0%	43.0%	60.0%	327	364	503	125	148	196	136	160	208
2001	7,550	35.0%	43.0%	60.0%	329	366	506	124	140	195	136	160	200
2002	7,585	35.0%	43.0%	60.0%	331	369	509	124	148	195	136	160	208

YEAR	POOL SIZE	SIZE OF POOL REQUIRING OXYGENATES-M bpd LOW OXY	BASE OXY	HIGH OXY	MTBE IMPORTS* LOW OXY	BASE OXY	HIGH OXY	BUTANE IMPORTS LOW OXY	BASE OXY	HIGH OXY	LOW OXY	BASE OXY	HIGH OXY
1991	7,274	0	0	0	-7	-7	-7	39	39	39	23	24	24
1992	7,334	587	587	587	2	-2	-2	28	27	27	30	29	29
1993	7,490	1,198	1,190	1,190	1	-3	-3	31	30	30	34	33	33
1994	7,545	1,207	1,207	1,207	-34	-57	-57	31	24	24	37	28	28
1995	7,590	2,657	3,264	4,554	57	71	184	77	101	148	46	70	118
1996	7,550	2,643	3,247	4,530	48	53	142	88	112	159	50	74	122
1997	7,490	2,622	3,221	4,494	45	49	137	98	122	169	54	78	126
1998	7,475	2,616	3,214	4,485	44	48	136	109	133	180	58	82	130
1999	7,485	2,620	3,219	4,491	44	48	137	129	153	200	64	88	136
2000	7,515	2,630	3,231	4,509	46	50	139	130	162	209	70	94	142
2001	7,550	2,643	3,247	4,530	40	53	142	138	162	207	74	98	146
2002	7,585	2,655	3,262	4,551	50	55	146	140	172	219	71	95	143

1995 U.S. MTBE CAPACITIES - M bpd	LOW OXY	BASE OXY	HIGH OXY
	300	325	375

MTBE REQUIRED FOR OCTANE PURPOSES ONLY (M bpd)	1991	1992	'93 & 94	'95 & After
	95	85	50	0

* ASSUMES THE FOLLOWING CONSTRUCTION OF NEW U.S. BASED MTBE PRODUCTION BEYOND WHAT HAS ALREADY BEEN ANNOUNCED.
LOW CASE -75 M bpd, BASE CASE -100 M bpd, & HIGH CASE - 150 M bpd
ALSO ASSUMES THAT PRESENT MTBE PRODUCTION USED FOR OCTANE PURPOSES ONLY (95 M bpd) WILL BE SHIFTED OVER 4 YEARS FOR USAGE IN CAA MANDATED AREAS. PHASE-OUT OF OCTANE ONLY MTBE IS SAME FOR ALL 3 CASES; 95 M bpd In 1991 for OCTANE ONLY, 85 M bpd IN 1992, and approximately 50 M bpd In 1993 and 1994. STARTING IN 1995 WE ASSUME THAT NO MTBE WILL BE USED FOR OCTANE PURPOSES ONLY UNTIL THE U.S. BECOMES MTBE "LONG".

Table A-22

BASE CASE M Tons/year			
United States	**1992**	**1995**	**2000**
% of Pool Affected	16	35	35
MTBE Demand	6,421	16,679	16,573
MTBE Production Capacity	6,866	15,225	17,215
MTBE Production	5,853	13,040	14,718
MTBE Imports	568	3,640	1,855

In our medium case study we have assumed that all **serious** ozone non-attainment areas will "opt-in" to use oxygenates. Assuming this happens in 1995, an additional 8% of the U.S. gasoline pool would require oxygenates -- bringing the total oxygenated share of the U.S. gasoline pool to 43% of the pool.

The medium case assumes also that U.S. ethanol capacities (used by the gasoline pool) will grow by 25% to 3.0 MM tons/year and TAME production will grow to about 1.7 MM tons/year (about 35% of potential capacity). Presently, only about 20% of all alcohol enhanced gasoline (gasohol) is being marketed within CAA non-attainment areas. In all three cases (base, medium and high) we have assumed better redistribution of gasohol sales and the percent of total gasohol sales to CAA non-attainment areas growing from 20% to 64% by 1996.

Our medium case study concluded the following:

MEDIUM CASE M Tons/year			
United States	**1992**	**1995**	**2000**
% of Pool Affected	16	43	43
MTBE Demand	6,421	18,893	18,437
MTBE Production Capacity	6,866	16,325	18,315
MTBE Production	5,853	13,997	15,660
MTBE Imports	568	4,896	2,777

The high case we have examined for this study assumes all ozone non-attainment areas not presently affected by the Clean Air Act (serious, moderate and marginal) opt-in to use oxygenates. Under this scenario (which would also include the CO and severe ozone non-attainment areas required by law), we estimate 60% of the U.S. gasoline pool will require oxygenates. The following table summarizes the conclusions of the high case.

HIGH CASE M Tons/year			
United States	**1992**	**1995**	**2000**
% of Pool Affected	16	60	60
MTBE Demand	6,421	26,962	24,896
MTBE Production Capacity	6,866	17,435	19,425
MTBE Production	5,853	14,924	16,608
MTBE Imports	568	12,038	8,288

Regardless of the case (base, medium or high), the U.S. has a difficult task ahead to meet the oxygenate requirements of the Clean Air Act of 1990. Offshore MTBE production is expected to reach 6.5 MM tons by year-end 1993. MTBE is rapidly becoming a commodity with a global demand base. Europe, Taiwan, South Korea, Malaysia, Mexico, and other foreign countries are now using MTBE to handle both octane and clean air requirements. The U.S. simply cannot count on reaching compliance with CAA oxygenate standards via MTBE imports. No one disputes MTBE's ability to clean up exhaust emissions of older cars. Older model cars make of the vast majority of automobiles in most all lessor developed and/or third world countries. This being the case, we believe it is safe to assume MTBE demand in other parts of the world will continue to grow for both octane and clean air reasons.

Although world-scale MTBE facilities (12,500 BPD) dependent on isobutane dehydrogenation-sourced isobutylene cost upwards of $250 MM (U.S. Gulf Coast grassroots), current economics suggest a favorable business investment. We are encouraged by announcements and rumors that suggests that several MTBE and TAME projects have now received boardroom approval. We are told that one large contractor has 12 MTBE projects committed to, but the contracting parties have asked to remain anonymous. CD TECH, a Pasadena, Texas, leader in TAME, is reported to have a large number of MTBE/TAME projects in the making (perhaps as many as 14 in the U.S. have licensed their technology) and another 4 U.S.-based companies have bought CD TECH's technology for TAME.

On the subject matter of TAME, we believe the court is no longer out on this fuel ether. Possessing both a high octane and a low vapor pressure (4 psi), TAME offers many benefits -- particularly if a refinery is isobutylene poor and isoamylene rich. We have spoken to one of the refiners planning to install a TAME unit and gained this insight: producing TAME (instead of blending isoamylene directly into the gasoline pool) lowers overall olefins content (a problem we believe will be addressed in the next round of CAA amendments), increases overall pool octane and lowers gasoline RVP. The latter two create both octane and RVP credits, allowing a refiner to add a lower RVP blendstock (like natural gasoline, which is very low in aromatics) and adding normal butane back into the pool to increase the gasoline RVP. Thus, the addition of TAME to the pool lowers aromatics, creates a vehicle for lowering aromatics, takes care of some "unwanted" normal butane (which is high in octane) and is a very inexpensive process to boot (when compared to butane based MTBE production).

Bonner & Moore believes that these benefits will far outweigh the only known disadvantage of using TAME, namely the offensive odor the ether is reported to have (when blended to high concentrations). Several sources have told us that odor is no longer perceived to be a problem (with TAME).

As our case assumptions point out, we are still bearish on future developments with ethanol and/or ETBE. Much activity is being witnessed in MTBE and TAME projects and announcements. We have spoken to several industry contacts that feel future ethanol capacity additions will be slow in developing for two reasons:

- Ethanol projects are at best "only viable" with a tax subsidy.
- Most company planners feel that a 10 year credit isn't sufficient or long enough to minimize the risk for an ethanol project. Instead, most companies feel if the tax subsidy could be extended 5 years to create a 15 year incentive, then a project's payout would be guaranteed and several companies would be willing to take the risk.

Despite the bevy of proposals and announcements in the press, the United States will be oxygenate "short" in 1992. Too much of the existing gasoline pool uses MTBE strictly for octane reasons (approximately 95 MBPD) and will consume most of the MTBE needed to meet oxygenate requirements that go into effect on November 1 of this year. We believe that the refining industry will not implement the proper planning and procedures required to ensure that all logistics and distributions problems are sufficiently addressed to meet the oxygenated fuel program requirements.

Bonner & Moore believes that the EPA will very likely take some type of measures to handle this serious oxygenate availability problem. Either the EPA will delay imposition of the oxygenate requirements, or will temporarily lower the required levels. The latter is the more likely scenario to develop.

One assumption we make that prompts explaining is that ethanol enhanced gasoline (gasohol) markets will shift more in favor (from 20% to 64%) to sales within CAA non-attainment areas.

This assumption regarding ethanol is based on opinions we developed in conducting the research for several reformulated gasoline studies and on discussions we have had with the EPA. We do realize that a shift of gasohol markets from attainment areas to non-attainment areas would not be in compliance with the "anti-dumping" regulations that are part of the Act. In essence, in no case can the quality of the future gasoline pool in a given geographic location be inferior to that location's baseline gasoline analysis. Lowering the ethanol content would more than likely create an analysis inferior to the baseline analysis. However, we presently feel that because of an overall shortage in oxygenate capacities, a concession will be made by the EPA regarding shifting markets for gasohol.

Case Assumptions

All three cases are based on two assumptions: that gasoline be blended to 2.7% by weight oxygen in both CO-non attainment areas and ozone non-attainment areas (based on our belief that the refining industry does not want to make several grades of oxygenated gasoline), and that the market share of gasohol being marketed to non-attainment areas increases over the next five years. The following additional assumptions were made in each of the three cases we have provided:

Base Case

In our base case scenario we basically assumed that future oxygenate markets develop following the **"letter of the law"**; that is, oxygenates will only be marketed to the actual areas mandated in the Clean Air Act: **namely, CO non-attainment areas and severe ozone non-attainment areas.** Furthermore, we assume that no new ethanol capacities will be added (this opinion based on poor economics and producer dissatisfaction with the 10 year tax subsidy), and that TAME production within the U.S. will grow to about 0.6 MM tons/year. The base case illustrates that 35% of the U.S. gasoline pool will require oxygenates by the year 1995.

Additionally, the base case assumes that a logistics factor of 25% be added to the share of the pool requiring oxygenates. This factor will account for the much needed extra production required to handle scheduling, transportation, distribution, and logistics problems associated with marketing ethers to non-attainment areas. Our base case scenario also assumes that a 1.5-month front shoulder "blending period" is required to ensure oxygenated fuels is in stock at all satellite storage and distribution terminals by the November 1 deadline.

Although ethanol capacities are not growing under the base case scenario, the actual market share of gasohol marketed within CAA non-attainment areas is growing. Presently, the EPA estimates that 20% of all gasohol is marketed within CAA non-attainment areas. Over the course of five years, this case study shows a growth from 20% to 64% of all gasohol being marketed within CAA non-attainment areas by the year 1996 (**Table A-23**). We realize this would be in violation of the CAA's "anti-dumping" regulation, but our assumption is based on opinions we formulated after discussing this subject matter with the EPA.

Medium Case

In our medium case study, we assume that **all serious ozone non-attainment areas "opt-in" to use oxygenates.** This increases the 1995 share of the pool requiring oxygenates from 35% to 43% of the U.S. gasoline pool. Furthermore, we assume that U.S. ethanol capacities will grow by 25% to 3.0 MM tons/year, and that TAME capacities within the U.S. grows to 1.7 MM tons/year (or 35% of total potential).

Additionally, the medium case assumes that a logistics factor of 25% be added to the share of the pool requiring oxygenates. This factor will account for the much needed extra production required to handle scheduling, transportation, distribution, and logistics problems associated with marketing ethers to non-attainment areas. Our medium case scenario also assumes that a 1.5-month front shoulder "blending period" is required to ensure oxygenated fuels is in stock at all satellite storage and distribution terminals by the November 1 deadline.

CLEAN AIR ACT OF 1990 OXYGENATE, ETHERS, & ALCOHOL REQUIREMENTS

YEAR	SIZE OF GASOLINE POOL M bpd	% OF POOL REQUIRING OXYGENTATES LOW CASE Percent	BASE CASE Percent	HIGH CASE Percent	MTBE REQUIREMENTS LOW CASE M bpd	BASE CASE M bpd	HIGH CASE M bpd	ETHANOL/ETBE REQUIREMENTS LOW CASE M bpd	BASE CASE M bpd	HIGH CASE M bpd	TAME REQUIREMENTS LOW CASE M bpd	BASE CASE M bpd	HIGH CASE M bpd
1991	7,274	0.0%	0.0%	0.0%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1992	7,334	8.0%	8.0%	8.0%	63	59	59	55	55	55	0	3.5	3.5
1993	7,490	16.0%	16.0%	16.0%	132	120	120	55	55	55	3	6	6
1994	7,545	16.0%	16.0%	16.0%	126	103	103	55	60	60	6	20	20
1995	7,590	35.0%	43.0%	60.0%	339	384	548	55	65	70	8	35	55
1996	7,550	35.0%	43.0%	60.0%	329	366	506	55	70	82.5	13	40	70
1997	7,490	35.0%	43.0%	60.0%	326	363	501	55	70	82.5	13	40	70
1998	7,475	35.0%	43.0%	60.0%	325	362	500	55	70	82.5	13	40	70
1999	7,485	35.0%	43.0%	60.0%	326	362	500	55	70	82.5	13	40	70
2000	7,515	35.0%	43.0%	60.0%	327	364	503	55	70	82.5	13	40	70
2001	7,550	35.0%	43.0%	60.0%	329	366	506	55	70	82.5	13	40	70
2002	7,585	35.0%	43.0%	60.0%	331	369	509	55	70	82.5	13	40	70

CASE DEFINITIONS

LOW OR MINIMUM CASE

1. "Letter of the Law" if followed.
2. All CO non-attainments areas blend oxygenates for 5.5 months, a combination of the 4 month minimum -- plus a 1.5 month front shoulder for ensuring gasoline at all bulk storage facilities are in compliance by Nov. 1 of each year.
3. All severe ozone non-attainment areas blend oxygenates 12 months out of the year.
4. A logistics factor of 25% (or 20% of total) has been applied to recognize that manufacturing, marketing, scheduling, transportation, and distribution problems will require refiners to produce more oxygenated gasoline than a strict definition of the affected areas would require.

BASE CASE

1. "Letter of the Law" if followed.
2. All CO non-attainments areas blend oxygenates for 5.5 months, a combination of the 4 month minimum -- plus a 1.5 month front shoulder for ensuring gasoline at all bulk bulk storage facilities are is in compliance by Nov. 1 of each year.
3. All severe ozone non-attainment areas blend oxygenates 12 months out of the year.
4. A logistics factor of 25% (or 20% of total) has been applied to recognize that manufacturing, marketing, scheduling, transportation, and distribution problems will require refiners to produce more oxygenated gasoline than a strict definition of the affected areas would require.

PLUS:

5. **All serious ozone non-attainment areas "opt-in" to require oxygenates.**

HIGH CASE

1. "Letter of the Law" if followed.
2. All CO non-attainments areas blend oxygenates for 5.5 months, a combination of the 4 month minimum -- plus a 1.5 month front shoulder for ensuring gasoline at all bulk bulk storage facilities are is in compliance by Nov. 1 of each year.
3. All severe ozone non-attainment areas blend oxygenates 12 months out of the year.
4. A logistics factor of 25% (or 20% of total) has been applied to recognize that manufacturing, marketing, scheduling, transportation, and distribution problems will require refiners to produce more oxygenated gasoline than a strict definition of the affected areas would require.
5. All serious ozone non-attainment areas "opt-in" to require oxygenates.

PLUS:

6. **All moderate and marginal ozone non-attainment areas "opt-in" to require oxygenates.**

ASSUMPTIONS

LOW OR MINIMUM CASE

1. Numbers shown above do not reflect MTBE that will be required for octane purposes only.
2. U.S. ethanol capacities do not grow.
3. % of alcohol enhanced gasoline marketed in CAA affected areas increases from 20% to 64%.
4. U.S. TAME production caps at 13 M bpd, or slightly over 10% of maximum potential.

BASE CASE

1. Numbers shown above do not reflect MTBE that will be required for octane purposes only.
2. U.S. ethanol capacities grow by 25%
3. Gasohol sales from existing sources to CAA mandated areas grows from 20% of total gasohol sales to 64%, while 100% of new ethanol capacity is marketed in CAA mandated areas.
4. U.S. TAME production caps at 35 M bpd, about 35% of maximum potential production.

HIGH CASE

1. Numbers shown above do not reflect MTBE that will be required for octane purposes only.
2. U.S. ethanol capacities grow by 50%.
3. Gasohol sales from existing sources to CAA mandated areas grows from 20% of total gasohol sales to 64%, while 100% of new ethanol capacity is marketed in CAA mandated areas.
4. U.S. TAME production caps at 70 M bpd, about 60% of maximum potential production.

Table A-23

In this case, as in our base case, the actual market share of gasohol marketed within CAA non-attainment areas is growing. Presently, the EPA estimates that 20% of all gasohol is marketed within CAA non-attainment areas. Over the course of 5 years this case study shows a growth from 20% to 64% of all gasohol being marketed within CAA non-attainment areas by the year 1996. As stated earlier, we realize this would be in violation of the CAA's "anti-dumping" regulation, but our assumption is based on opinions we formulated after discussing this subject matter with the EPA.

High Case

In our high case study, we assume that **ALL ozone non-attainment areas "opt-in" to use oxygenates.** This increases the 1995 share of the pool requiring oxygenates from 35% (in the low case) to 60% **(Table A-24)** of the U.S. gasoline pool. Furthermore, we assume that U.S. ethanol capacities will grow by 50% to 3.6 MM tons/year, and that TAME capacities within the U.S. grows to 3.0 MM tons/year (or 60% of total potential).

Additionally, the high case assumes that a logistics factor of 25% be added to the share of the pool requiring oxygenates. This factor will account for the much needed "extra" production required to handle scheduling, transportation, distribution and logistics problems associated with marketing ethers to non-attainment areas. Our high case scenario **does not assume** that a 1.5-month front shoulder "blending period" be required to ensure oxygenated fuels is in stock at all satellite storage and distribution terminals by the November 1 deadline because oxygenates would be required year-round.

In this case, as in our other two cases, the actual market share of gasohol marketed within CAA non-attainment areas is growing. Presently, the EPA estimates that 20% of all gasohol is marketed within CAA non-attainment areas. Over the course of five years this case study shows a growth from 20% to 64% of all gasohol being marketed within CAA non-attainment areas by the year 1996. As stated earlier, we realize this would be in violation of the CAA's "anti-dumping" regulation, but our assumption is based on opinions we formulated after discussing this subject matter with the EPA.

Oxygenate Market Shares

To determine the share of the gasoline pool requiring oxygenates under each of the three case studies, we conducted an extensive evaluation of the population base of each of the cities classified as non-attainment areas by the Environmental Protection Agency. Based on the latest U.S. census data for each city and metropolitan area, along with recent state by state gasoline sales data, we listed the gasoline pool shares for each non-attainment area type. This data was then used to compile the percentages listed in this study.

FEEDSTOCK REQUIREMENTS FOR TOTAL U.S. MTBE DEMAND
AS REQUIRED BY MINIMUM REGS
M bpd

YEARS:	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
TOTAL METHANOL REQUIRED	33.6	52.2	64.5	62.5	120.0	116.4	115.3	115.0	115.2	115.8	116.4
TOTAL ISOBUTYLENE REQUIRED	76.3	118.4	146.2	141.7	272.1	264.1	261.5	260.9	261.4	262.6	264.1
FROM ONSITE REFINERIES	24.7	21.9	41.4	55.6	56.0	55.7	55.2	55.1	55.2	55.4	55.7
FROM OTHER REFINERIES	2.0	13.3	16.7	16.8	17.0	17.2	17.3	17.5	17.7	17.9	18.0
FROM STEAM CRACKERS	8.4	9.4	10.1	10.7	11.1	11.5	11.9	11.9	12.2	12.6	12.9
FROM ISOBUTANE DEHYDRO	20.5	45.0	45.0	47.1	50.5	53.9	53.9	53.9	53.9	53.9	53.9
ISOBUTYLENE FROM OTHER SOURCES	26.2	27.2	25.9	29.8	32.0	32.0	32.0	32.0	32.0	32.0	32.0
TOTAL ISOBUTYLENE SHORTFALL	-5.5	1.6	7.2	-18.3	105.5	93.9	91.2	90.5	90.4	90.8	91.6
FROM CURRENT & ANNOUNCED PLANTS	-0.0	-0.0	-0.0	0.0	5.2	1.6	1.5	1.4	0.8	-0.0	-0.7
FROM PROJECTED MTBE SHORTFALL	-5.5	1.6	7.2	-18.3	100.3	92.3	89.7	89.1	89.6	90.8	92.3
CURRENT & ANNOUNCED NGL REQUIRMENTS											
ISOBUTANE FROM NGL MARKETS	9.4	10.0	10.0	10.2	10.9	10.9	10.9	10.9	10.9	10.9	10.9
ISOBUTANE FRM INTEGRATED ISOM	11.3	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9
ISOBUTANE FROM MERCHANT ISO	3.8	7.9	7.8	10.1	13.5	17.5	17.5	17.5	17.5	17.5	17.5
N-BUTANE REQUIRED FOR ISOM	15.0	43.4	43.4	45.7	49.0	53.0	53.0	53.0	53.0	53.0	53.0
MTBE & IC4= REQUIREMENTS											
FUTURE U.S. MTBE ADDITIONS	0.0	0.0	12.5	12.5	75.0	75.0	75.0	75.0	75.0	75.0	75.0
FUTURE IC4 DEHYDROGENATION	0.0	0.0	12.0	12.0	78.2	73.9	73.8	73.6	72.9	72.0	71.2
ISOBUTANE FROM NGL MARKETS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ISOBUTANE FROM NEW NC4 ISOM	0.0	0.0	12.0	12.0	78.2	73.9	73.8	73.6	72.9	72.0	71.2
N-BUTANE REQUIRED FOR ISOM	0.0	0.0	11.9	11.9	77.7	73.4	73.3	73.1	72.4	71.5	70.7
MTBE IMPORTS TO BALANCE IC4=	-6.9	2.0	-2.3	-34.1	57.5	47.5	44.3	43.5	44.1	45.6	47.5
U.S. MTBE BALANCE	-0.0	-0.0	0.0	0.0	-0.0	0.0	-0.0	-0.0	-0.0	-0.0	0.0

TOTAL BUTANES REQUIRED BY EXISTING, ANNOUNCED & POTENTIAL MTBE PRODUCERS FOR MINIMUM OXYGENATE REGS

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
ISOBUTANE FROM MARKETS	9.4	10.0	10.0	10.2	10.9	10.9	10.9	10.9	10.9	10.9	10.9
ISOBUTANE FROM ISOMERIZATION	15.1	43.7	55.7	58.0	127.6	127.3	127.1	127.0	126.3	125.3	124.5
TOTAL ISOBUTANE:	24.5	53.7	65.7	68.2	138.5	138.2	138.1	137.9	137.2	136.3	135.5
TOTAL NORMAL BUTANE	15.0	43.4	55.3	57.6	126.7	126.4	126.2	126.1	125.4	124.5	123.7

ASSUMPTIONS

BARRELS OF ISOBUTANE PER BARREL MTBE	0.960
BARRELS OF METHANOL PER BARREL OF MTBE	0.354
BARRELS OF ISOBUTYLENE PER BARREL OF MTBE	0.803
DEHYDROGENATION EFFICIENCY	92.50%
NORMAL BUTANE ISOMERIZATION YIELD	99.30%

EXAMPLE:

12,500 BPD MTBE PLANT REQUIRES,
10,040 BPD OF ISOBUTYLENE,
PLUS 4,425 BPD OF METHANOL

ISOBUTYLENE CAN BE PRODUCED FROM:
11,915 BPD OF ISOMERIZED N-BUTANE FEED
OR, 12,000 BPD OF PURITY ISOBUTANE FEED

Table A-24

The Auto/Oil Industry Task Force Study and Issues

Our study looked at three case assumptions: base, medium and high. Prior to press time, the findings of an auto/oil industry task force assigned to conduct a research program regarding the effects of reformulating gasoline on providing cleaner air. The results of the recent study caught many industry observers by surprise: namely, that oxygenates (including MTBE) are ineffective in reducing summertime ozone. The study did find that oxygenates are effective in reducing winter carbon monoxide pollution. The study found that while MTBE reduces hydrocarbons by 5%, the hydrocarbons that are made have a higher reactivity toward producing smog. In short, it does not improve smog (according to the study) because the emissions are more photochemically reactive.

What the auto/oil study did recommend as two solutions for reducing smog was reducing the T90 (90% point of the gasoline boiling range) to 280 degrees Fahrenheit and decreasing gasoline olefins. Ironically, the study found that two requirements actually mandated by the Clean Air Act, reducing aromatics and adding oxygenates, are not effective in reducing smog; where two of the issues once considered but overlooked by the law (lowering olefins and reducing T90), were found to be very effective in controlling smog.

Tests were performed for the study in Los Angeles, Dallas-Fort Worth, and New York City. The study found that decreasing the gasoline olefin content from 20% to 5%, reduced ozone in all 3 cities -- primarily by lowering the ozone-forming potential of evaporative emissions. Also, lowering the T90 to 280°F reduced smog in all 3 cities.

One would naturally assume that these "new" findings should justify Bonner & Moore's analyzing a fourth case, the **Auto/Oil Industry Task Force Case.** We purposely put the word "**new**" in quotes because although the auto/oil study proclaims they are "new," similar claims or reports have been reported before and they did not change the outcome of the Clean Air Act. This is not to say that the auto/oil findings will be dismissed immediately and cast aside. We expect much to the contrary. Although many people believe that the "train has already left the station" on MTBE, the list of "heavyweights" on the auto/oil task force is impressive enough to believe we have not heard the last from these folks. However, we understand that testing methodologies and analytical procedures used for this study and others cast sufficient doubt about the study's conclusions to cause us to believe they will be under a great deal of scrutiny.

Keep in mind that in the big scheme of things, the issues at question here are very political. Congress is by no way or means going to take these findings and simply admit "we goofed." We do believe, however, that before these "new" findings can have an impact, the EPA will be asked to supervise, monitor, and certify all testing procedures and methodologies used to confirm or deny these findings with future tests. If this should take place and the EPA confirms these new findings, Congress could walk away without having any public "egg on its face" by allowing the EPA to establish a new list of cities and time frames that would require the use of oxygenates in gasoline. In essence, we would still have a Clean Air Act, oxygenates would still be mandated (at least within CO non-attainment areas) yet restricted, but an amendment would be forthcoming regarding olefins and/or T-90.

To properly determine the implications of these findings would require a separate case study based on LP modeling of the U.S. refining industry. Bonner & Moore has initiated such a study and is in the process of conducting this very demanding analysis at this time. However, in analyzing these results we have concluded that several issues should be explored within the context of this study that puts the auto/oil task force findings in a proper prospective. The more important issues are:

- Reducing the olefins content removes a high octane component, with most gasoline olefins having a blending octane value of 91-93 R+M/2.

- Lowering the T-90 to 280°F results in rejection of high octane components also, since some of the higher boiling point share of the gasoline pool is aromatics (raising some question to the task force's claim that aromatic reduction does not reduce smog). Nonetheless, at issue here is "what will replace the lost octane resulting from the removal of olefins and lowering the T-90?"

- Will reduction of olefins result in expansion of alkylation capacities?

- Will olefin reduction result in a rapid growth in TAME production to convert isoamylenes to a fuel oxygenate?

- Will lowering olefins from the task force's estimate of 20% of the U.S. gasoline pool to 5% result in a 15% decline in U.S. refinery production? Is the task force correct in assuming the average U.S. gasoline pool has 20% olefins?

A more likely answer to all of these issues is a government mandate that would require lowering the T-90 and lowering gasoline olefins, which would result in some refiners increasing alkylation capacities, more TAME production coming on-line, changes in reformer operating rates and severities, changes in cat cracker catalysts, and other investments in refinery operations that would be required to meet such a mandate. In short, each refiner would invest dollars in technologies that would best suit their individual operations. However, making adjustments in olefins and boiling points that reduces octane will result in an octane shortage in many cases. After exploring this matter in more detail, we believe that MTBE will be the most practical octane substitute for octane lost in lowering olefins or the T-90 boiling point.

The auto/oil industry study lowered olefins content from 20% to 5%. If such a reduction became a government mandate and lost olefinic octanes were replaced with MTBE, the upside potential for MTBE as an octane enhancer (for replacing olefins) would be 0.84 barrels MTBE for every barrel of olefin removed but not substituted (by conversion to alkylate or some other acceptable octane source). Approximately the same ratio of MTBE replacement for lowering the T-90 could be used. In essence, a total replacement of 15% of the pool (the olefin share that would be removed) with MTBE would require 12.75% by volume MTBE in the final gasoline pool. The upside potential is merely theoretical and not practical, since it is impossible to remove all olefins without some sort of conversion (i.e., alkylation) process.

The low side case for MTBE for the auto/oil industry scenario would be that 16.3% of the gasoline pool would require oxygenates, since this is the market share held by the CO non-attainment segment of the market (including front shoulder blending and a logistics factor of 25%). The addition of severe ozone non-attainment areas requires another 18.7% of the pool contain oxygenates. This segment (18.7%) of our low case scenario (where 35% of the gasoline pool would require reformulation) would be nullified if the auto/oil task force findings ever result in changes in the current Clean Air Act. It should be noted that under the current law the EPA has discretion over this matter.

Making an assumption that 72.7% of all C3= and C4= olefins removal is accomplished via alkylation and that 50% of all isoamylene (C5= olefins) is converted to TAME, the total demand for MTBE for both CO non-attainment area CAA requirements and octane requirements to replace the missing octane from olefins removed (but not converted) and heavy boilers (to comply with a 280°F T-90) would approximate the 16.6 MM tons/year (in the year 1995) base case scenario developed for this study (prior to the auto/oil industry task force findings).

Stricter Requirements for Diesel Fuels Beginning in 1993

In addition to regulating the various fuel parameters of motor gasoline, the Clean Air Act Amendments of 1990 provide for stricter specifications on diesel fuels. Of particular interest is the provision for lower sulfur-content limits in diesel fuels.

The nationwide standard for the maximum allowable sulfur content of highway diesel fuels has been a maximum of 0.50% sulfur by weight, with a lower regional standard of 0.30% in California. As of October 1, 1993, it is unlawful to produce, sell, or dispense any motor vehicle diesel fuel with a sulfur concentration in excess of 0.05% weight or which fails to meet a Cetane Index minimum of 40. The EPA is to establish an aromatics level which is consistent with the Cetane Index specification.

Regulations have been set forth for the interim period 1991 to 1993. During these years, diesel fuel used in certification of heavy duty diesel vehicles must meet a 0.10% by weight sulfur limit. Thereafter, diesel fuels must meet the requirements described below.

Section 231 of the Clean Air Act Amendments of 1990 charge the EPA with exploring alternatives to motor vehicle diesel fuels. Specifically, the EPA is required to select a laboratory to investigate the feasibility, engine performance, emissions, and production capability associated with a fuel composed of ethanol and high erucic rapseed oil. They are mandated to report to Congress on the viability of this alternative to diesel fuel in 1994.

APPENDIX B
U.S. REFINING INDUSTRY PROFILE
BASE CASE 1990

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U.S. REFINING INDUSTRY PROFILE
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SECTION 1

U.S. REFINING CAPACITY CHARACTERIZATION

BACKGROUND

The petroleum refining industry has played its role quite well as a "middle man" when taking, at times, heroic strides to guarantee crude producers market access, especially when qualitatively crudes are unable to satisfy the demands of the consumer. The refining industry's main contribution has been the development of technology and capital investments for which it has not commanded lavish profit margins, rather than expectations of long-term economic growth which would allow the viability of these investments.

In the past, the refinery, as just another component of a vertically-integrated industry, was sometimes allowed marginal performance, since its existence solely justified crude production, and the overall corporate profitability was achieved elsewhere. Today, a greater number of refineries operate as independent profit centers, and are, therefore, more vulnerable to the general well-being of the economy.

In order to characterize the current status of the U.S. refining industry properly, we must examine the prevailing petroleum market environment associated with this industry during the last decade. Although a thorough analysis is beyond the scope of this study, a few highlights will help set the proper framework of the industry's evolutionary process.

The single most important market-driven events successfully challenged by U.S. refineries to date (without significant disruptions) have been the motor gasoline lead phasedown and the need to accommodate declining consumption of residual fuels for electric power generation. Possibly both consumers and the industry itself have responded rather passively to these new trends because their attentions seem to be focused on the gyrations of the world petroleum market during this period. This situation notwithstanding, significant investments took place for the production of high octane components, quality stabilization, and "bottom of the barrel conversion" during the last ten years.

OPERABLE CAPACITY OF U.S. PETROLEUM REFINERIES
(Thousand Barrels per Stream Day, except where noted)

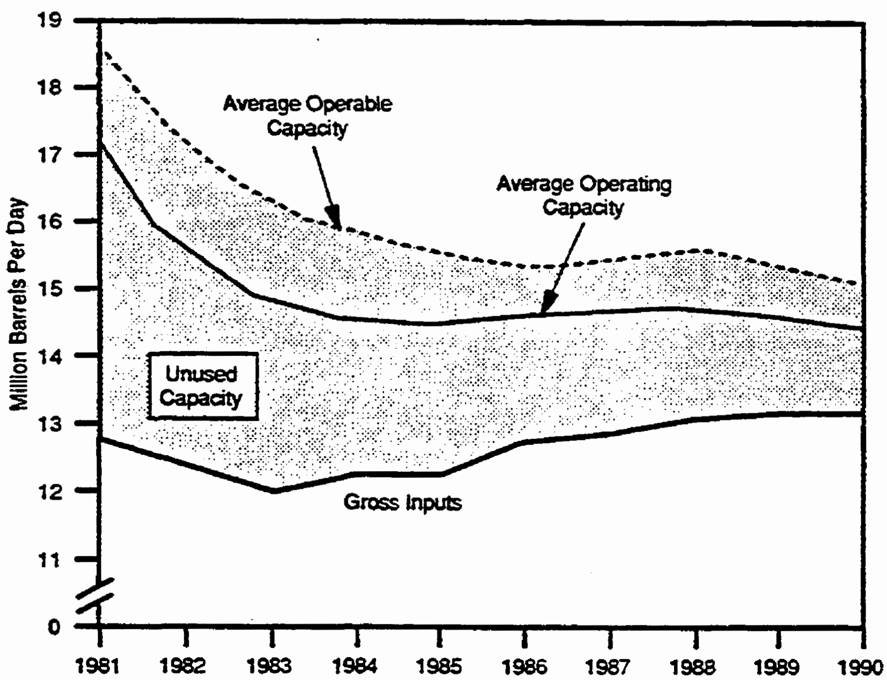
As of January 1 of Year	Crude Distillation (thousand barrels per calendar day)	Vacuum Distillation	Thermal Cracking: Fluid & Delayed Coking	Thermal Cracking: Visbreaking & Other	Catalytic Cracking Fresh & Recycled	Catalytic Reforming	Catalytic Hydro-Cracking	Catalytic Hydro-Treating
1981	18,621	7,033	1,021	566	6,136	4,098	909	8,487
1982	17,890	7,197	1,146	635	6,036	3,966	892	8,539
1983	16,859	7,180	1,198	518	5,890	3,918	883	8,354
1984	16,137	7,165	1,393	459	5,802	3,907	952	9,009
1985	15,659	6,998	1,407	451	5,738	3,750	1,053	8,897
1986	15,459	6,892	1,435	444	5,677	3,744	1,125	8,791
1987	15,566	6,935	1,464	464	5,716	3,805	1,189	9,083
1988	15,915	7,198	1,515	565	5,806	3,891	1,202	9,170
1989	15,655	7,225	1,516	557	5,650	3,911	1,238	9,440

As a result of these capital expenditures, the thermal conversion to distillation capacity ratio was nearly twofold during the decade, and the U.S. refining industry provided itself with the necessary operational flexibility to address the consumer's qualitative demands within the prevailing regulatory constraints in a profitable manner.

YIELD ON CRUDE (Percent)

	1982	1984	1986	1988	1990
Finished Gasoline	45.5	46.1	46.5	45.9	45.6
Distillate	20.1	21.0	20.1	21.5	21.9
Resid	9.3	6.3	6.1	5.9	6.0
Pet Coke	3.0	3.2	3.8	4.0	3.9

Currently, with approximately one-third of the world's existing refineries (705), the U.S. refining capacity represents about 20% of the world refining capability (74.9 MMBPCD). The available capacity declined significantly in 1990, from an all time peak of 18.6 MMBPCD at the beginning of 1980s.



The future of the U.S. refining industry is closely tied to the occurrence of events described in the **Appendix A, Worldwide Petroleum Balance, Section 1**, as well as to the need to reinvest in technology necessary to comply with the regulatory standards set by the 1990 Clean Air Act (described in **Appendix A, Worldwide Petroleum Balance, Section 2**).

DOE PROPOSED REFINING REGIONS

For the purpose of this study, which is to identify the required additional refinery conversion capacity should incremental domestic heavy crude oil become available during the next twenty years, the Department of Energy (DOE) has proposed ten regions to be evaluated (**Figure B-1**). These designated regions differ from the known Petroleum Administration for Defense Districts (PADDs), and represent areas where potential domestic heavy crude can be produced.

Region	Description
1	Florida, Georgia, South Carolina, North Carolina, New York, New Jersey, Pennsylvania, Virginia, Maryland, West Virginia
2	Illinois, Indiana, Kentucky, Michigan,North Dakota, Ohio, South Dakota, Minnesota, Iowa, Wisconsin, Tennessee
3	Oklahoma, Kansas, Missouri,Nebraska, Arkansas (excluding some counties in Region 5), some counties of northern Texas
4	Arizona, Washington, Oregon, sections of California not included in Regions 8 through 10
5	Texas (excluding some northern counties in Region 3), New Mexico, Louisiana, some counties of southern Arkansas, Mississippi, and Alabama
6	Wyoming, Utah, Colorado, Montana, Idaho, Nevada
7	Alaska
8	Central coast of California, including Monterey, San Luis Obispo, and Santa Barbara Counties
9	Southern California, including Los Angeles, Ventura, and Orange Counties
10	San Joaquin Valley of California (Kern, Fresno, Kings and Tulare Counties)

Northern counties of Texas included in Region 3: Archer, Baylor, Clay, Collin, Cook, Dallas, Delta, Denton, Fannin, Foard, Grayson, Hardeman, Hopkins, Hunt Jack Kaufman, Knox, Lamar, Montague, Parker, Palo Pinto, Rockwall, Tarrant, Throckmorton, Wichita, Wilbarger, Wise, Young

Southern counties of Arkansas included in Region 5: Ashley, Bradley, Calhoun, Columbia, Hempstead, Lafayette, Miller, Nevada, Ouachita, Union

The refining industry profile used as the 1990 Base Case has been developed according to these new regions. Sources of data used to characterize the 1990 Base Case are generally presented in terms of PADDs. For this reason, and because data of actual logistics and movements of petroleum crude and refined products in the United States is either scarce, privately controlled, or otherwise unavailable, the qualitative breakdown, in terms of the ten DOE regions, necessarily incorporates some judgment from Bonner & Moore consultants.

U.S. HEAVY OIL REFINING CAPACITY PROPOSED REGIONAL ANALYSIS

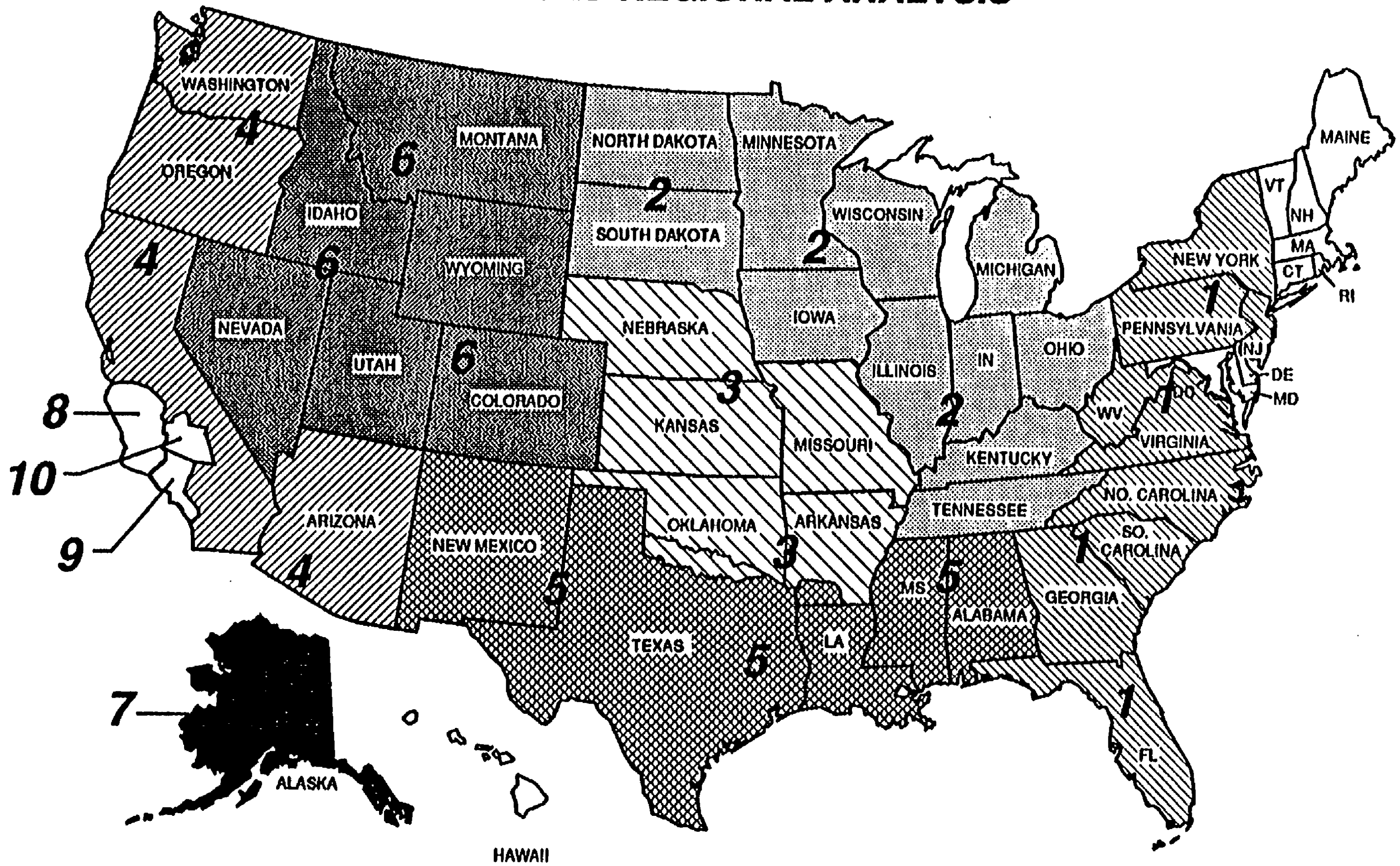


Figure B-1

BASE CASE 1990 REFINING CAPACITY

The following comments serve to make the 1990 U.S. operable refining capacity figures more understandable.

- **Stream-day** figures correspond to running the units at full capacity (nameplate), while **calendar-day** figures represent the average throughput, which includes downtimes and turnarounds (**Table B-1**).

- As of January 1, 1991 (available capacity during 1990), the U.S. refining industry's nameplate capacity totalled 16.3 MMBPSD. Assuming an average utilization rate of near 95%, the corresponding calendar-day available capacity would be about 15.4 MMBPCD.

  However, from research of factual refinery utilization rates, the actual capacity was around 13.9 MMBPCD, corresponding to a utilization rate of approximately 85%. This number is the base case distillation capacity used throughout the study.

  Details of the refineries, their ownerships, and specific geographic locations are presented at the end of this section.

- A geographical breakdown of the U.S. distillation capabilities clearly indicates that Regions 5, 2, 1, and 4 are the areas with significant processing capacity. Regions 5 and 1, because of their direct access to deep water ports, are more dependent on foreign crude imports to make up the refinery charge volume requirements.

  A description of the qualitative composition of the crude charge into the different DOE regions is presented below.

- During 1990, the refining industry responded to mounting environmental concerns, and earmarked investments to meet reduced emission motor gasoline specifications before the end of 1992. Capacities of primary downstream refining processes which yield gasoline and diesel logged gains, while processes that treat feeds for the primary units increased because of feed demand for conversion and light fuels. The gains in downstream capacity reflect the industry's effort to meet increasingly stringent air quality regulations which require higher oxygen content gasolines in winter and less volatile gasolines in summer.

To understand the distribution of the different process capacities among the 194 refineries in the U.S. during 1990, the following information is helpful.

U.S. REFINING CAPACITY
SUMMARY BASE CASE 1990

DOE	CRD	VAC	THRM	FCC	REF	Hydro Process CRK	Hydro Process REFINE	Hydro Process TRT	ALK	POLY	ISOM	AROM	LUBE	ASPH	DEASP	H2	COKE
	MB/SD															MMCF/SD	MT/SD
Region 1	1,608.9	728.6	91.0	602.5	344.7	74.5	107.0	808.6	85.5	15.0	42.3	17.7	32.3	146.5	10.5	103.2	4.0
Region 2	2,766.1	1,143.7	301.0	1,015.0	738.0	153.7	293.7	1,305.8	202.4	12.0	127.5	67.8	19.5	228.1	13.5	158.8	12.1
Region 3	809.6	274.2	72.5	275.5	195.3	8.2	70.0	326.8	69.6	5.6	68.5	5.4	10.0	19.1	16.3	10.0	3.2
Region 4	1,451.9	847.6	225.4	372.5	340.5	289.5	287.5	543.0	70.0	9.4	11.7	--	20.3	58.7	54.5	597.0	9.1
Region 5	7,232.9	3,008.8	871.5	2,555.6	1,795.4	522.0	1,327.1	3,443.6	526.1	40.1	237.7	222.0	133.5	176.2	185.4	1,014.1	32.4
Region 6	583.1	219.9	28.4	201.3	128.7	9.9	50.1	225.9	34.1	7.5	17.4	--	--	46.8	16.5	25.3	1.0
Region 7	404.4	77.3	42.5	20.0	25.0	27.0	--	26.5	4.5	1.1	5.5	2.5	--	10.4	--	32.9	--
Region 8	10.0	7.8	--	--	--	--	--	--	--	--	--	--	--	6.8	--	--	--
Region 9	1,309.1	704.5	360.9	402.0	307.0	161.2	296.5	569.0	80.2	3.0	10.5	--	--	47.2	--	515.4	14.9
Region 10	128.0	54.2	23.7	--	26.5	14.3	16.5	19.4	--	--	--	--	9.1	9.0	--	21.0	0.7
	16,304.0	7,066.5	2,016.9	5,444.4	3,901.0	1,260.3	2,448.4	7,268.6	1,072.4	93.7	521.0	315.4	224.7	748.7	296.7	2,477.7	77.5

Net Thruput Factors (Bbls CD/Cap SD)

	CRD	VAC	THRM	FCC	REF	CRK	REFINE	TRT	ALK	POLY	ISOM	AROM	LUBE	ASPH	DEASP	H2	COKE
	*	*	*	*		*											*
PADD I	0.865	0.865	0.839	0.879	0.9	0.680	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.1	0.9	0.9	0.92
PADD II	0.892	0.892	0.849	0.820	0.9	0.715	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.1	0.9	0.9	0.92
PADD III	0.838	0.835	0.895	0.839	0.9	0.729	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.1	0.9	0.9	0.92
PADD IV	0.833	0.833	0.622	0.794	0.9	0.714	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.1	0.9	0.9	0.92
PADD V	0.849	0.849	0.870	0.862	0.9	0.813	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.1	0.9	0.9	0.92

* = 4 yr. average (PSA 1990)

DOE	CRD	VAC	THRM	FCC	REF	Hydro Process CRK	Hydro Process REFINE	Hydro Process TRT	ALK	POLY	ISOM	AROM	LUBE	ASPH	DEASP	H2	COKE
	MB/CD															MMCF/CD	MT/CD
Region 1	1,391.9	630.2	76.3	529.6	310.2	50.7	96.3	727.7	77.0	13.5	38.0	15.9	29.1	146.5	9.5	92.9	3.7
Region 2	2,467.4	1,020.2	255.5	832.3	664.2	109.9	264.3	1,175.2	182.2	10.8	114.8	61.0	17.6	228.1	12.2	142.9	11.2
Region 3	722.4	244.5	61.6	225.9	175.8	5.9	63.0	294.1	62.6	5.0	61.7	4.9	9.0	19.1	14.7	9.0	3.0
Region 4	1,232.8	719.6	196.1	321.1	306.5	235.4	258.8	488.7	63.0	8.5	10.5	--	18.3	58.7	49.1	537.3	8.3
Region 5	6,059.7	2,512.3	780.0	2,144.1	1,615.9	380.5	1,194.4	3,099.2	473.5	36.1	213.9	199.8	120.2	176.2	166.9	912.7	29.8
Region 6	485.7	183.2	17.7	159.8	115.8	7.1	45.1	203.3	30.7	6.8	15.7	--	--	46.8	14.9	22.8	0.9
Region 7	343.3	65.6	37.0	17.2	22.5	22.0	--	23.9	4.1	1.0	5.0	2.3	--	10.4	--	29.6	--
Region 8	8.7	6.6	--	--	--	--	--	--	--	--	--	--	--	6.8	--	--	--
Region 9	1,111.4	598.1	314.0	346.5	276.3	131.1	266.9	512.1	72.2	2.7	9.5	--	--	47.2	--	463.9	13.7
Region 10	108.7	46.0	20.6	--	23.9	11.6	14.9	17.5	--	--	--	--	8.2	9.0	--	18.9	0.6
	13,932.0	6,026.4	1,758.8	4,576.6	3,510.9	954.0	2,203.6	6,541.7	965.2	84.3	468.9	283.8	202.2	748.7	267.0	2,229.9	71.3

Table B-1

U.S. REFINERY CAPACITY
BASE CASE 1990

	Refining Capacity MBPSD	
	More Than 200	**Less Than 200**
No. of Companies	20	92
No. of Refineries	88	106
Crude Capacity	12,295,520	4,008,434
FF Cat Cracking	4,299,900	1,144,500
% on Crude	35.0	28.6
Cat Reforming	3,083,000	818,520
% on Crude	25.1	20.4
Hydrocracking	1,134,600	126,190
% on Crude	9.2	3.1
Hydro-Process	4,693,450	817,650
% on Crude	39.0	20.4
Alkylation	835,700	240,000
% on Crude	7.0	6.0
Coking	1,376,200	239,100
% on Crude	11.2	6.0

- The figures indicate that approximately one-fourth of the capacity is in smaller refineries which are operated by a greater number of companies, mostly independents with less financial backing. As we have indicated, the ongoing concern of the refining industry is its ability to maintain healthy economic margins (assuming crude costs remain near reasonable levels), and be able to meet tougher rules governing air emissions of motor fuels.

- The U.S. refining industry's profitability in 1990 performed favorably when compared with previous year's levels.

- Refiners in Regions 4, 8, 9, and 10 lead the way, with consolidated profit margins slightly above $3.50/B. One reason for this lead is their access to lower cost crudes.

  Results of Region 1 refineries average margins in the $2.50/B range, while Region 3, the refining sector with the highest degree of complexity in the country, posted lower margins around the $2.20/B level. The U.S. central Regions 3, 4, and 6, secured profitabilities in the $2.00/B range.

- In the longer term, as the industry becomes volumetrically more dependent on foreign crudes, profitability in the different regions will be even more contingent on the price actions resulting from worldwide supply/demand conditions.

- Although the details of the full impact of the net available capacities after 1990 will be covered in Volume I of the final report, a summary of the known and expected refinery shutdowns, as shown below, is useful.

ANNOUNCED/EXPECTED CAPACITY SHUTDOWNS		
DOE Region	Name/Location	Crude Capacity MPSD
3	Farmland - Phillipsburg, KS	27.5
5	Chevron - Port Arthur, TX	324.5
6	Amoco - Casper, WY	41.0
7	Chevron - Kenai, AK	22.5
9	Fletcher - Carson, CA	30.0
9	Edington - Long Beach, CA	44.7
9	Golden West - Santa Fe Springs, CA	46.0
9	Unocal - Los Angeles, CA	111.0
	Total	647.2

At this moment, without considering the possibility of some new distillation capacity expansion during the next five years, the U.S. refining industry could very well be faced with nearly 550 MBPCD (at 86% utilization) less capacity available if all of the announced shutdowns actually materialize.

REFINERY CRUDE INTAKE QUALITY

The U.S. refineries made up more than half of their crude needs from domestic production during 1990. Imports, which accounted for 44% of the crude intake, performed as an average 31.4 degrees API quality crude, with 1.4 weight percent sulphur (**Table B-2**).

Of the ten DOE geographical areas under study, the following is true:

- Only Region 8, in California, processed a "heavy crude oil" as defined in the study's terms of reference; i.e., less than 20 degrees API.

- The vast majority of the remaining refineries processed light sweet crude, well above the 30 degrees API threshold.

  This situation seems to be common for most U.S. refineries, with the exception of the remainder of California (Regions 4, 9, 10), which traditionally has processed on average what the world petroleum industry classifies as "medium" gravity crudes (greater than 20 and less than 30 degrees API).

A quality breakdown between the three accepted industry crude classifications shows the following:

- Regions 3, 6, and 7 process no heavy crude oil in the crude intake slate.

- Refineries in Region 7, which encompasses Alaska and Hawaii, do not have the capability of properly converting heavier crude oils into marketable products.

U.S. REFINING CRUDE INTAKE BY DOE REGION
1990 BASECASE

REGION	1	2	3	4	5	6	7	8	9	10	TOTAL
REFINERY CAPACITY											
Nameplate, MBSD	1,609	2,766	810	1,452	7,233	583	404	10	1,309	128	16,304
Max Allowed, MBCD	1,392	2,467	722	1,233	6,040	486	343	9	1,111	109	13,932
CRUDES PROCESSED											
Actual, MBCD	1,284	2,329	683	1,193	6,060	460	237	8	1,046	108	13,409
Gravity, API	31.0	34.0	36.3	24.3	33.1	35.5	29.5	13.8	26.3	27.3	31.9
Sulfur, Wt%	1.1	1.1	0.6	1.1	1.1	0.9	0.9	3.3	1.1	0.7	1.1
Domestic, MBCD	12	1,311	650	1,109	2,835	405	217	8	887	108	7,542
Gravity, API	31.0	36.6	36.3	23.5	35.4	34.9	28.6	13.8	23.9	27.3	32.3
Sulfur, wt%	0.3	0.9	0.6	1.2	0.6	1.0	1.0	3.3	1.3	0.7	0.8
Imports, MBCD	1,272	1,018	33	85	3,225	55	20	0	159	0	5,867
Gravity, API	31.0	30.6	36.7	34.4	31.1	39.6	38.5	--	39.5	--	31.4
Sulfur, Wt%	1.1	1.4	1.1	1.0	1.6	0.4	0.1	--	0.1	--	1.4

Table B-2

- Refineries in Regions 3 and 6 have access to significant production of domestic light sweet crudes and, therefore, only a few of their existing configurations have capabilities for heavy crude handling and processing (Table B-3).

- As one would expect, Regions 5 and 1 have a greater proportion of crude imports available for processing. The refinery configuration in these areas can accept heavier sour crudes which, coincidentally, correspond with the qualities available from South America and some Middle Eastern sources.

U.S. REFINING CRUDE INTAKE BY DOE REGION
1990 BASECASE
(MB/D)

Region		API	% SUL	1	2	3	4	5	6	7	8	9	10	TOTAL
Region 1	Light	35.2	0.75	779										779
	Medium	27.7	1.09	405										405
	Heavy	13.3	2.36	100										100
Region 2	Light	37.0	0.78	..	1,671									1,671
	Medium	25.0	1.96	..	643									643
	Heavy	0.0	0.00	..	15									15
Region 3	Light	38.8	0.60	..	..	572								572
	Medium	27.3	1.09	..	..	111								111
	Heavy	0.0	0.00	..	..	0								0
Region 4	Light	35.8	0.73	..	..	..	92							92
	Medium	27.7	1.12	..	..	..	774							774
	Heavy	13.0	1.35	..	..	..	328							328
Region 5	Light	36.4	0.93	..	..	..	..	4,574						4,574
	Medium	25.8	1.56	..	..	..	..	1,225						1,225
	Heavy	13.2	2.07	..	..	..	..	261						261
Region 6	Light	38.4	0.53	..	..	..	..	..	365					365
	Medium	24.0	2.50	..	..	..	..	..	95					95
	Heavy	0.0	0.00	..	..	..	..	..	0					0
Region 7	Light	36.2	0.11	..	..	..	..	..	..	50				50
	Medium	27.7	1.11	..	..	..	..	..	..	187				187
	Heavy	0.0	0.00	..	..	..	..	..	..	0				0
Region 8	Light	0.0	0.00	..	..	..	..	..	..	..	0			0
	Medium	0.0	0.00	..	..	..	..	..	..	..	0			0
	Heavy	13.8	3.34	..	..	..	..	..	..	..	8			8
Region 9	Light	38.4	0.17	..	..	..	..	..	..	..	..	212		212
	Medium	27.7	1.11	..	..	..	..	..	..	..	..	540		540
	Heavy	15.0	1.85	..	..	..	..	..	..	..	..	294		294
Region 10	Light	34.4	0.45	..	..	..	..	..	..	..	..	..	61	61
	Medium	29.5	0.68	..	..	..	..	..	..	..	..	..	14	14
	Heavy	13.3	1.33	..	..	..	..	..	..	..	..	..	33	33
				1,284	2,329	683	1,194	6,060	460	237	8	1,046	108	13,409
		Gravity, API		31.0	34.0	36.3	24.3	33.1	35.5	29.5	13.8	26.3	27.3	31.9
		Sulfur, Wt%		1.1	1.1	0.6	1.1	1.1	0.9	0.9	3.3	1.1	0.7	1.1

TOTAL USA

	MBCD	API	% SUL
Light	8,376	36.5	0.8
Medium	3,994	26.5	1.4
Heavy	1,039	13.7	1.7
Total	13,409	31.9	1.1

Table B-3

ADDENDUM TO SECTION 1

U.S. REFINING CAPACITY

BASE CASE 1990

SUBSTANTIATING TABLES

U.S. REFINING CAPACITY
BASE CASE 1990

COMPANY	DOE REG	ST	CITY	CRD	VAC	THRM	FCC	REF	Hydro Process CRK	Hydro Process REFINE	Hydro Process TRT	ALK	POLY	ISOM	AROM	LUBE	ASPH	DEASP	H2	COKE
				MB/SD															MMCF/SD	MT/SD
Amerada-Hess Corp	01	NJ	Port Reading	--	--	--	50.0	--	--	--	--	4.5	5.0	--	--	--	--	--	--	--
Amoco Oil Co	01	VA	Yorktown	56.0	29.0	14.0	27.5	10.2	--	--	26.5	--	--	--	--	--	--	--	--	0.8
Amoco Oil Co	01	GA	Savannah	30.0	--	--	--	--	--	--	--	--	--	--	--	--	22.5	--	--	--
BP Oil Co	01	PA	Marcus Hook	180.0	75.0	--	50.0	48.0	21.0	42.0	100.0	12.0	--	--	--	--	--	--	--	--
Chevron USA Inc	01	NJ	Perth Amboy	85.0	46.0	--	--	--	--	--	--	--	--	--	--	--	35.0	--	--	--
Chevron USA Inc	01	PA	Philadelphia	180.0	80.0	--	62.0	34.0	--	--	64.0	18.0	--	--	5.3	--	--	--	--	--
Cibro Petroleum	01	NY	Albany	42.0	25.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Coastal Eagle Point	01	NJ	Westville	115.0	45.0	10.0	50.0	27.0	--	--	60.8	4.0	2.5	9.3	2.0	--	--	--	--	--
Exxon Co	01	NJ	Linden	135.0	66.0	--	120.0	28.0	--	50.0	113.0	13.5	--	25.0	--	--	38.0	--	--	--
Mobil Oil Corp	01	NJ	Paulsboro	107.0	64.2	21.0	36.0	23.5	--	15.0	70.4	6.5	--	--	--	8.5	--	9.5	11.0	1.1
Pennzoil Products	01	PA	Rouseville	16.5	6.5	--	--	5.8	--	--	14.8	--	--	1.2	--	4.8	--	--	3.5	--
Pheonix Refining	01	WV	St. Mary's	20.0	2.0	--	--	1.5	--	--	--	--	--	--	--	2.0	--	1.0	1.5	--
Quaker State	01	WV	Newell	10.8	8.9	--	--	3.4	4.5	--	3.9	--	--	--	--	4.4	--	--	1.2	--
Seaview Petroleum	01	NJ	Thorofare	78.9	30.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Star Enterprise	01	DE	Delaware City	150.0	95.0	46.0	69.0	56.0	19.0	--	110.0	11.5	5.5	--	3.4	--	--	--	40.0	2.2
Sun Refining	01	PA	Marcus Hook	185.0	46.0	--	87.0	39.6	--	--	87.7	12.0	--	--	7.0	10.0	--	--	6.0	--
Sun Refining	01	PA	Philadelphia	130.0	83.0	--	29.0	50.0	30.0	--	128.0	--	--	--	--	--	35.0	--	40.0	--
United Refining	01	PA	Warren	68.0	27.0	--	22.0	16.0	--	--	26.0	3.5	2.0	6.8	--	--	12.0	--	--	--
Witco Chemical	01	PA	Bradford	11.5	--	--	--	1.7	--	--	3.5	--	--	--	--	2.6	--	--	--	--
Young Refining	01	GA	Douglasville	8.2	--	--	--	--	--	--	--	--	--	--	--	--	4.0	--	--	--
				1,608.9	728.6	91.0	602.5	344.7	74.5	107.0	808.6	85.5	15.0	42.3	17.7	32.3	146.5	10.5	103.2	4.0

Table B-4

U.S. REFINING CAPACITY
BASE CASE 1990

COMPANY	DOE REG	ST	CITY	CRD	VAC	THRM	FCC	REF	......Hydro Process...... CRK	REFINE	TRT	ALK	POLY	ISOM	AROM	LUBE	ASPH	DEASP	H2	COKE
				....	....	....	....	....	....	....	MB/SD	....	....	....	....	....	....	....	MMCF/SD	MT/SD
Amoco Oil Co	02	ND	Mandan	60.0	--	--	26.0	12.1	--	--	19.1	4.3	--	5.1	--	--	--	--	--	--
Amoco Oil Co	02	IN	Whiting	360.0	203.0	28.0	145.0	85.0	--	86.0	161.3	29.0	--	22.0	14.0	6.4	45.0	--	--	1.6
Ashland Petroleum	02	OH	Canton	68.0	33.0	--	25.0	20.0	--	23.0	33.5	7.0	0.5	6.5	--	--	12.0	--	--	--
Ashland Petroleum	02	MN	St. Paul Par	69.2	32.0	--	23.0	23.5	--	23.0	40.0	5.5	0.4	8.3	--	--	14.0	--	--	--
Ashland Petroleum	02	KY	Catlettsburg	220.0	92.0	57.6	100.0	52.0	--	40.0	141.0	12.0	1.0	12.0	5.4	8.5	30.0	--	--	--
BP Oil Co	02	OH	Toledo	127.0	49.0	15.0	55.0	42.0	35.0	--	37.0	11.3	--	--	--	--	7.0	--	24.0	0.8
BP Oil Co	02	OH	Lima	150.0	41.0	18.0	34.0	55.0	24.0	--	60.0	--	--	17.0	31.4	--	--	--	--	0.7
Clark Oil	02	IL	Hartford	60.0	30.0	14.5	26.0	12.0	--	--	28.0	8.0	--	4.0	--	--	--	--	2.5	0.8
Clark Oil	02	IL	Blue Island	70.0	27.0	--	25.0	30.5	9.0	--	20.5	6.0	--	--	--	--	7.0	--	--	--
Crystal Refining	02	MI	Carson City	6.2	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Indian Refining	02	IL	Lawrenceville	57.0	30.0	--	34.0	15.0	--	--	48.0	5.0	--	--	--	--	5.0	--	--	--
Indiana Farm Bureau	02	IN	Mt. Vernon	21.5	7.2	--	7.0	4.0	--	--	6.0	1.7	--	2.0	--	--	--	--	--	--
Koch Refining Co	02	MN	Rosemount	230.0	160.0	58.0	55.0	32.0	--	63.5	87.0	8.5	4.8	15.0	--	--	35.0	--	20.0	2.8
Lakeside Refining	02	MI	Kalamazoo	5.9	--	--	--	1.0	--	--	--	--	--	--	--	--	--	--	--	--
Laketon Refining	02	IN	Laketon	10.0	6.0	--	--	--	--	--	--	--	--	--	--	--	3.5	--	--	--
Mapco Petroleum	02	TN	Memphis	62.0	12.0	--	30.0	10.0	--	--	31.0	3.0	2.5	4.0	--	--	3.5	--	--	--
Marathon Petroleum	02	IL	Robinson	205.0	62.0	26.0	43.0	77.5	24.0	6.0	65.0	12.0	--	14.0	--	--	--	--	25.0	1.2
Marathon Petroleum	02	IN	Indianapolis	50.0	17.0	--	19.5	10.5	--	--	13.5	6.0	--	--	--	--	2.5	4.5	--	--
Marathon Petroleum	02	MI	Detroit	71.0	38.0	--	27.0	18.5	--	17.0	21.0	4.0	--	--	--	--	18.0	--	--	--
Mobil Oil Corp	02	IL	Joliet	200.0	88.0	38.0	98.0	46.0	--	--	156.0	25.0	--	--	--	--	--	--	--	2.4
Murphy Oil USA Inc	02	WI	Superior	34.0	20.5	--	11.0	8.0	--	5.8	9.0	1.3	--	2.0	--	--	13.5	--	--	--
Shell Oil Co	02	IL	Wood River	286.0	108.0	18.0	94.0	93.0	33.5	29.0	154.0	22.0	--	--	4.5	4.6	28.5	--	28.3	--
Somerset Refinery	02	KY	Somerset	6.3	--	--	--	1.0	--	0.4	1.3	--	--	0.2	--	--	--	--	--	--
Sun Refining	02	OH	Toledo	133.0	30.0	--	60.0	45.6	28.2	--	40.0	7.8	2.8	--	9.0	--	--	9.0	48.0	--
Total Petroleum	02	MI	Alma	51.0	--	--	19.5	14.0	--	--	29.8	5.0	--	8.0	--	--	--	--	--	--
Uno-Ven Co	02	IL	Lemont	153.0	58.0	27.9	58.0	29.8	--	--	103.8	18.0	--	7.4	3.5	--	3.6	--	11.0	2.0
				2,766.1	1,143.7	301.0	1,015.0	738.0	153.7	293.7	1,305.8	202.4	12.0	127.5	67.8	19.5	228.1	13.5	158.8	12.1

Table B-5

U.S. REFINING CAPACITY
BASE CASE 1990

COMPANY	DOE REG	ST	CITY	CRD	VAC	THRM	FCC	REF	Hydro Process CRK	Hydro Process REFINE	Hydro Process TRT	ALK	POLY	ISOM	AROM	LUBE	ASPH	DEASP	H2	COKE
				MB/SD															MMCF/SD	MT/SD
Barrett Refining	03	OK	Thomas	12.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Coastal Refining	03	KS	Augusta	--	--	--	--	10.0	--	--	14.5	--	--	6.5	--	--	--	--	--	--
Coastal Refining	03	KS	Wichita	31.5	10.0	5.5	19.0	6.5	--	--	7.0	2.8	3.5	--	--	--	--	--	--	--
Coastal Refining	03	KS	El Dorado	32.0	12.0	--	14.5	4.5	--	--	4.0	2.8	--	--	--	--	2.5	5.5	--	--
Conoco Inc	03	OK	Ponca City	145.0	45.0	20.5	53.0	36.0	--	--	66.0	12.0	2.1	14.5	--	2.0	--	--	--	--
Cyril Petrochemical	03	OK	Cyril	13.2	--	--	--	--	--	--	1.8	--	--	--	--	--	--	--	--	--
Farmland Industries	03	KS	Phillipsburg	27.5	10.0	--	--	5.3	--	--	7.5	--	--	--	--	--	2.0	--	--	--
Farmland Industries	03	KS	Coffeyville	62.0	21.5	12.0	25.0	16.0	--	--	33.0	6.0	--	8.0	--	--	--	--	--	0.7
Kerr-McGee Refining	03	OK	Wynnewood	45.0	13.0	--	20.0	12.5	5.0	--	11.5	5.0	--	4.0	--	--	5.0	5.0	10.0	--
Liquid Energy Corp	03	TX	Bridgeport	10.8	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
National Co-Op	03	KS	McPherson	75.0	27.0	22.0	20.0	15.0	--	--	39.0	6.0	--	11.5	--	--	--	--	--	0.7
Sinclair Oil Corp	03	OK	Tulsa	52.6	26.5	--	18.0	12.0	--	--	17.0	3.0	--	6.0	--	--	2.5	--	--	--
Sun Refining	03	OK	Tulsa	90.0	29.0	--	30.0	24.0	--	--	34.5	7.0	--	3.0	5.4	8.0	4.6	5.8	--	0.3
Texaco Refining	03	KS	El Dorado	83.0	32.0	12.5	31.5	18.5	--	44.0	49.0	12.5	--	15.0	--	--	--	--	--	0.6
Total Petroleum	03	OK	Ardmore	70.0	32.0	--	25.0	17.0	--	26.0	24.0	7.0	--	--	--	--	--	--	--	--
Total Petroleum	03	KS	Arkansas City	60.0	16.2	--	19.5	18.0	3.2	--	18.0	5.5	--	--	--	--	2.5	--	--	--
				809.6	274.2	72.5	275.5	195.3	8.2	70.0	326.8	69.6	5.6	68.5	5.4	10.0	19.1	16.3	10.0	3.2
Atlantic Richfield	04	WA	Ferndale	176.0	95.0	50.0	--	56.0	52.0	18.0	38.0	--	--	--	--	--	--	--	80.0	2.5
BP Oil Co	04	WA	Ferndale	95.0	35.0	--	28.5	16.5	--	--	17.0	6.0	--	--	--	--	--	--	--	--
Chevron USA	04	CA	Richmond	280.0	175.0	--	63.0	60.0	110.5	125.0	84.2	7.0	2.1	--	--	11.0	11.0	50.0	150.0	--
Chevron USA	04	OR	Portland	--	16.0	--	--	--	--	--	--	--	--	--	--	--	11.5	--	--	--
Chevron USA	04	WA	Seattle	--	6.0	--	--	--	--	--	15.0	--	0.9	--	--	--	5.0	--	--	--
Exxon Oil Co	04	CA	Benicia	132.0	67.0	27.5	65.0	32.0	32.0	37.0	91.0	14.0	2.0	--	--	--	--	--	104.0	1.1
Huntway Refining	04	CA	Benicia	9.0	7.5	--	--	--	--	--	--	--	--	--	--	--	4.5	--	--	--
Intermountain	04	AZ	Fredonia	6.0	2.0	--	--	--	--	--	--	--	--	--	--	--	1.2	--	--	--
Pacific Refining	04	CA	Hercules	55.0	25.0	12.0	--	15.0	4.0	--	13.0	--	--	--	--	--	--	--	--	--
Shell Oil Co	04	WA	Anacortes	92.5	44.0	--	42.0	26.0	--	7.5	52.5	11.0	--	2.8	--	--	--	--	--	--
Shell Oil Co.	04	CA	Martinez	148.0	101.5	21.0	66.0	28.0	28.0	50.0	76.3	9.0	2.2	--	--	4.5	11.0	--	118.0	0.1
Sound Refining	04	WA	Tacoma	12.8	6.0	--	--	--	--	--	--	--	--	--	--	--	3.0	--	--	--
Sunbelt Refining	04	AZ	Randolph	10.0	6.0	--	--	--	--	--	--	--	--	--	--	--	3.5	--	--	--
Texaco Refining	04	WA	Anacortes	133.0	50.0	22.0	48.0	24.0	--	--	61.0	10.0	2.2	--	--	--	--	4.5	--	1.2
Tosco Corp	04	CA	Martinez	143.0	118.0	46.0	60.0	43.0	29.0	50.0	34.0	13.0	--	--	--	--	--	--	80.0	1.5
Unocal Corp	04	CA	San Francisco	125.1	74.1	46.9	--	34.0	34.0	--	49.5	--	--	7.4	--	4.8	--	--	65.0	2.6
US Oil and Refining	04	WA	Tacoma	34.5	19.5	--	--	6.0	--	--	11.5	--	--	1.5	--	--	8.0	--	--	--
				1,451.9	847.6	225.4	372.5	340.5	289.5	287.5	543.0	70.0	9.4	11.7	--	20.3	58.7	54.5	597.0	9.1

Table B-6

U.S. REFINING CAPACITY
BASE CASE 1990

COMPANY	DOE REG	ST	CITY	CRD	VAC	THRM	FCC	REF	......Hydro Process...... CRK	REFINE	TRT	ALK	POLY	ISOM	AROM	LUBE	ASPH	DEASP	H2	COKE
				....	....	....	....	....	....	....	MB/SD	....	....	....	....	....	....	....	MMCF/SD	MT/SD
Amerada-Hess Corp	05	MS	Purvis	31.6	20.0	8.0	16.0	5.8	--	--	11.8	3.5	--	--	--	--	--	--	--	0.3
American Inter.	05	LA	Lake Charles	30.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Amoco Oil Co	05	TX	Texas City	460.0	195.0	42.8	200.0	160.0	120.0	85.0	244.0	62.0	--	28.0	45.0	--	--	--	180.0	2.2
Atlas Processing	05	LA	Shreveport	50.0	24.3	--	--	5.0	--	--	20.1	--	--	--	--	8.5	0.6	--	6.1	--
Berry Petroleum	05	AR	Stevens	6.0	3.0	--	--	--	--	--	--	--	--	--	--	--	0.9	--	--	--
Bloomfield Refining	05	NM	Bloomfield	18.1	--	--	6.0	4.0	--	--	4.0	--	2.0	--	--	--	--	--	--	--
BP Oil Co	05	LA	Belle Chasse	232.0	73.0	22.0	92.0	38.0	--	--	88.0	35.0	--	--	30.3	--	--	--	--	0.8
Calcasieu Refining	05	LA	Lake Charles	14.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Calumet Lubricants	05	LA	Princeton	4.5	8.6	--	--	--	--	--	4.5	--	--	--	--	3.6	0.9	--	4.5	--
Canal Refining Co	05	LA	Church Point	10.0	--	--	--	1.9	--	--	--	--	--	--	--	--	--	--	--	--
CAS Refining Inc	05	LA	Mermentau	14.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Champlin Refining	05	TX	Corpus Christi	137.0	80.0	32.0	70.0	52.0	--	95.0	54.0	19.0	--	--	8.0	--	--	--	--	1.8
Chevron USA Inc	05	TX	El Paso	68.0	54.0	--	22.0	25.0	--	21.5	25.0	5.5	--	3.0	--	--	5.5	--	--	--
Chevron USA Inc	05	MS	Pascagoula	310.0	243.0	75.0	64.0	90.0	68.0	189.0	48.0	16.2	--	--	5.5	--	20.0	--	215.0	4.0
Chevron USA Inc	05	TX	Port Arthur	324.5	156.0	34.0	110.0	67.1	--	--	250.0	16.9	--	7.2	16.8	10.0	--	--	--	1.8
Citgo Petroleum	05	LA	Lake Charles	330.0	75.0	88.0	150.0	106.0	45.0	40.0	134.0	23.0	--	23.0	4.0	9.0	--	--	--	4.0
Coastal Mobile	05	AL	Mobile Bay	15.0	14.0	--	--	--	--	--	--	--	--	--	--	--	10.0	--	--	--
Coastal Refining	05	TX	Corpus Christi	95.0	53.0	23.0	18.5	28.5	10.0	--	75.0	3.2	3.0	5.3	24.5	--	4.0	--	39.0	0.7
Conoco Inc	05	LA	Lake Charles	167.0	63.0	72.0	42.5	28.0	--	--	154.0	7.5	2.1	--	--	--	--	--	--	3.7
Cross Oil	05	AR	Smackover	7.0	--	--	--	--	--	--	4.5	--	--	--	--	3.5	2.1	--	0.5	--
Crown Central	05	TX	Houston	105.0	40.0	12.5	56.0	36.0	--	10.0	26.0	13.0	--	5.0	--	--	--	--	--	0.4
Diamond Shamrock	05	TX	Three Rivers	55.0	20.0	--	20.0	11.0	--	--	11.0	6.0	--	--	--	1.0	--	6.0	--	--
Diamond Shambrock	05	TX	Sunray	115.0	47.0	--	45.0	40.0	20.0	--	33.0	8.7	4.6	--	--	--	5.0	15.0	--	--
El Paso Refining	05	TX	El Paso	27.5	--	--	10.8	7.4	--	--	7.4	3.0	--	0.7	--	--	--	--	--	0.1
Ergon Refining Inc	05	MS	Vicksburg	18.3	12.0	--	--	--	--	3.8	--	--	--	--	--	3.6	12.0	--	2.5	--
Exxon Co	05	TX	Baytown	448.0	219.0	28.0	180.0	123.0	20.0	110.0	394.6	29.0	--	--	--	31.2	7.0	53.0	85.0	0.1
Exxon Co	05	LA	Baton Rouge	438.0	183.0	90.0	188.0	90.0	24.0	--	214.5	33.2	8.0	12.5	--	16.5	12.0	6.9	--	5.0
Fina Oil	05	TX	Port Arthur	115.0	50.0	--	36.0	34.0	--	31.0	73.0	5.5	--	8.5	10.0	--	2.0	18.0	--	--
Fina Oil	05	TX	Big Spring	60.0	24.0	--	22.0	20.0	--	6.0	43.0	5.0	--	--	1.0	--	0.7	10.0	--	--
Gamxx Energy Inc	05	AL	Theodore	28.5	--	--	--	5.0	--	--	11.0	--	--	--	--	--	--	--	--	--
Giant Industries	05	NM	Gallup	21.0	7.9	--	7.8	6.8	--	--	6.8	1.6	--	4.0	--	--	0.7	--	--	--
Hill Petroleum Co	05	TX	Texas City	130.7	64.0	--	50.0	23.0	--	--	52.0	6.0	--	--	--	--	--	--	--	--
Hill Petroleum Co	05	TX	Houston	71.0	39.0	--	61.0	13.5	--	--	44.0	4.0	--	--	2.0	--	--	17.0	--	--
Hill Petroleum Co	05	LA	St. Rose	30.0	24.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Hill Petroleum Co	05	LA	Krotz Spring	60.0	22.0	--	28.0	12.0	--	--	12.0	--	2.8	--	--	--	--	--	--	--
Howell Hydrocarbons	05	TX	San Antonio	2.9	--	--	--	1.2	--	--	--	--	--	--	1.0	--	--	--	--	--
Hunt Refining Co	05	AL	Tuscaloosa	47.0	15.0	12.0	--	6.0	--	14.8	7.5	--	--	....	--	--	9.5	--	6.0	0.4
Kerr-McGee Refining	05	LA	Cotton Valley	8.5	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Koch Refining	05	TX	Corpus Christi	130.0	42.0	12.0	40.0	48.5	--	--	57.5	8.4	--	--	10.8	--	--	--	--	0.4
LaGloria Oil	05	TX	Tyler	53.0	16.0	6.0	17.0	15.7	--	--	20.8	4.8	--	5.0	--	--	--	--	--	0.3
Leal Petroleum	05	TX	Nixon	17.5	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Table B-7

U.S. REFINING CAPACITY
BASE CASE 1990

COMPANY	DOE REG	ST	CITY	CRD	VAC	THRM	FCC	REF	......Hydro Process...... CRK	REFINE	TRT	ALK	POLY	ISOM	AROM	LUBE	ASPH	DEASP	H2	COKE
				....							MB/SD	....							MMCF/SD	MT/SD
Lion Oil Co	05	AR	El Dorado	50.0	25.0	--	18.5	9.0	--	--	15.5	4.8	--	3.0	--	--	6.5	5.5	--	--
Louisiana Land	05	AL	Saraland	81.3	20.0	--	--	20.0	--	15.0	30.0	--	--	7.0	--	--	--	--	--	--
Lyondell	05	TX	Houston	286.0	129.0	40.0	90.0	110.0	--	129.0	170.0	14.0	--	--	11.0	6.0	--	6.0	--	2.7
Marathon Petroleum	05	TX	Texas City	72.0	27.0	--	38.0	10.5	--	--	--	11.0	--	--	2.5	--	--	--	--	--
Marathon Petroleum	05	LA	Garyville	263.0	125.0	--	90.0	45.0	--	109.0	67.0	26.0	--	40.5	--	--	40.0	30.0	--	--
Mobil Oil Corp	05	LA	Chalmette	175.0	92.5	33.0	58.0	47.0	18.0	43.0	69.0	19.0	--	--	7.0	--	--	--	24.0	1.6
Mobil Oil Corp	05	TX	Beaumont	290.0	86.0	29.5	102.0	103.0	32.0	--	213.7	13.0	--	20.0	--	9.4	--	--	60.0	1.5
Murphy Oil	05	LA	Meraux	100.0	40.0	--	35.0	23.0	--	15.0	29.0	8.7	--	--	--	--	--	12.0	--	--
Navajo Refining	05	NM	Artesia	40.0	6.0	--	20.0	8.0	--	--	19.5	2.8	--	--	--	--	2.5	--	--	--
Phillips 66 Co	05	TX	Borger	110.0	--	--	60.0	26.0	--	90.0	26.5	14.0	--	35.6	3.1	--	--	--	50.0	--
Phillips 66 Co	05	TX	Sweeny	195.0	83.0	--	87.0	36.0	--	125.0	53.0	15.0	--	16.9	13.2	--	--	--	80.0	--
Placid Refining	05	LA	Port Allen	50.0	18.0	--	19.0	10.0	--	--	10.0	3.7	--	--	--	--	--	6.0	--	--
Pride Refining	05	TX	Abilene	46.5	12.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Shell Oil Co	05	TX	Odessa	29.5	--	--	10.5	10.0	--	--	11.0	3.3	--	--	0.4	--	--	--	--	--
Shell Oil Co	05	LA	Norco	220.0	78.0	127.7	--	54.0	35.0	70.0	57.0	15.0	9.4	--	--	--	--	--	70.0	1.0
Shell Oil Co	05	TX	Deer Park	227.0	87.5	72.0	65.0	63.0	65.0	45.0	189.5	8.1	--	--	19.5	12.5	5.4	--	65.0	--
Southland Oil Co	05	MS	Lumberton	6.5	--	--	--	--	--	--	--	--	--	--	--	--	3.5	--	--	--
Southland Oil Co	05	MS	Sandersville	12.5	--	--	--	--	--	--	--	--	--	--	--	--	5.1	--	--	--
Southwestern	05	TX	Corpus Christi	108.0	36.0	--	50.0	30.0	--	18.0	67.0	7.5	4.2	--	6.5	--	--	--	--	--
Star Enterprise	05	TX	Port Arthur	273.0	138.0	--	110.0	46.0	15.0	--	142.9	16.2	--	--	--	18.7	14.0	--	--	--
Star Enterprise	05	LA	Convent	240.0	75.0	12.0	85.0	40.0	50.0	--	142.0	14.5	4.0	12.5	--	--	--	--	62.5	--
Thriftway	05	NM	Farmington	5.0	--	--	--	0.5	--	--	--	--	--	--	--	--	--	--	--	--
Tifinery	05	TX	Corpus Christi	20.0	20.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Valero Refining	05	TX	Corpus Christi	27.0	24.0	--	65.0	--	--	62.0	--	9.5	--	--	--	--	--	--	64.0	--
				7,232.9	3,008.8	871.5	2,555.6	1,795.4	522.0	1,327.1	3,443.6	526.1	40.1	237.7	222.0	133.5	176.2	185.4	1,014.1	32.4

Table B-8

U.S. REFINING CAPACITY
BASE CASE 1990

COMPANY	DOE REG	ST	CITY	CRD	VAC	THRM	FCC	REF	Hydro Process CRK	Hydro Process REFINE	Hydro Process TRT	ALK	POLY	ISOM	AROM	LUBE	ASPH	DEASP	H2	COKE
				MB/SD															MMCF/SD	MT/SD
Amoco Oil Co	06	UT	Salt Lake	41.5	--	--	18.0	7.6	--	--	7.6	4.0	--	3.0	--	--	--	--	--	--
Amoco Oil Co	06	WY	Casper	41.0	14.0	--	13.5	7.1	--	--	7.3	2.5	--	--	--	--	0.6	--	--	--
Big West Oil Co	06	UT	Salt Lake	25.0	3.8	--	5.0	5.0	--	--	6.0	1.5	--	1.7	--	--	--	--	--	--
Cenex	06	MT	Laurel	42.5	14.0	--	12.0	12.0	--	14.0	15.0	3.0	--	2.0	--	--	6.0	4.0	--	--
Chevron USA	06	UT	Salt Lake	46.0	35.5	8.5	18.0	7.5	--	5.5	7.5	4.3	--	1.1	--	--	--	--	--	0.4
Colorado Refining	06	CO	Commerce	35.0	10.0	--	8.5	9.5	--	--	9.5	--	1.2	--	--	--	--	--	--	--
Conoco	06	MT	Billings	52.0	20.0	--	19.0	14.7	--	--	42.5	6.0	--	3.8	--	--	6.5	7.5	--	--
Conoco Inc	06	CO	Denver	50.0	23.0	--	19.0	10.0	--	--	22.8	--	2.6	--	--	--	5.0	--	--	--
Crysen Refining	06	UT	Woods Cross	13.4	4.0	--	--	3.0	--	--	--	--	--	--	--	--	--	--	--	--
Exxon Co	06	MT	Billings	44.0	18.0	7.7	21.0	10.0	4.9	--	41.5	3.4	--	--	--	--	11.0	--	19.3	0.4
Frontier Oil	06	WY	Cheyenne	38.0	20.0	8.0	11.5	6.6	--	8.0	7.2	3.0	--	2.5	--	--	10.0	--	--	--
Landmark Petroleum	06	CO	Fruita	16.0	8.1	4.2	--	3.4	5.0	--	3.4	--	--	--	--	--	--	--	6.0	0.2
Little America	06	WY	Casper	24.0	8.6	--	14.0	6.0	--	--	13.8	--	--	--	--	--	1.0	--	--	--
Montana Refining	06	MT	Great Falls	7.0	3.6	--	2.4	1.0	--	--	2.4	--	0.4	0.7	--	--	--	--	--	--
Pennzoil Products	06	UT	Roosevelt	8.5	--	--	6.0	2.0	--	--	2.0	--	2.6	--	--	--	--	--	--	--
Petro Source	06	NV	Tononpah	4.7	2.5	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Phillips 66 Co	06	UT	Woods Cross	26.0	4.8	--	8.4	6.0	--	1.6	11.0	2.1	--	2.6	--	--	1.7	5.0	--	--
Sinclair Oil Corp	06	WY	Sinclair	55.0	30.0	--	21.0	14.5	--	21.0	26.5	3.5	0.7	--	--	--	5.0	--	--	--
Wyoming Refining	06	WY	Newcastle	13.5	--	--	4.0	2.8	--	--	--	0.8	--	--	--	--	--	--	--	--
				583.1	219.9	28.4	201.3	128.7	9.9	50.1	225.9	34.1	7.5	17.4	--	--	46.8	16.5	25.3	1.0
ARCO Alaska Inc	07	AK	Kuparuk	12.0	--	12.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--
ARCO Alaska Inc.	07	AK	Prudhoe Bay	17.5	--	17.5	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Chevron USA Inc	07	AK	Kenai	22.5	--	--	--	--	--	--	--	--	--	--	--	--	6.0	--	--	--
Chevron USA Inc	07	HI	Barber's Pt.	55.0	31.3	--	20.0	--	--	--	3.5	4.5	1.1	1.5	--	--	1.3	--	2.5	--
Hawaiian Ind	07	HI	Ewa Beach	95.0	40.0	13.0	--	13.0	18.0	--	11.0	--	--	--	--	--	1.1	--	17.6	--
Napco Alaska	07	AK	North Pole	115.0	6.0	--	--	--	--	--	--	--	--	--	2.5	--	2.0	--	--	--
Petro Star Inc	07	AK	North Pole	7.4	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Tesoro Petroleum	07	AK	Kenai	80.0	--	--	--	12.0	9.0	--	12.0	--	--	4.0	--	--	--	--	12.8	--
				404.4	77.3	42.5	20.0	25.0	27.0	--	26.5	4.5	1.1	5.5	2.5	--	10.4	--	32.9	--
Conoco Inc	08	CA	Santa Maria	10.0	7.8	--	--	--	--	--	--	--	--	--	--	--	6.8	--	--	--

Table B-9

U.S. REFINING CAPACITY
BASE CASE 1990

COMPANY	DOE REG	ST	CITY	CRD	VAC	THRM	FCC	REF	......Hydro Process...... CRK	REFINE	TRT	ALK	POLY	ISOM	AROM	LUBE	ASPH	DEASP	H2	COKE
				....							MB/SD	....							MMCF/SD	MT/SD
Atlantic Richfield	09	CA	Carson	235.0	112.0	56.0	82.0	48.0	22.0	--	151.0	14.0	3.0	--	--	--	--	--	70.0	2.5
Chemoil Refining	09	CA	Signal Hill	16.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Chevron USA Inc	09	CA	El Segundo	279.0	114.0	61.1	62.0	51.0	45.0	114.0	70.0	8.0	--	--	--	--	--	--	130.0	3.3
Edgington Oil Co	09	CA	Long Beach	44.7	25.0	--	--	--	--	--	--	--	--	--	--	--	17.0	--	--	--
Fletcher Oil	09	CA	Carson	30.0	17.0	--	12.0	5.0	--	12.0	5.0	--	--	--	--	--	6.3	--	--	--
Golden West Ref	09	CA	Santa Fe Springs	46.0	25.0	13.8	13.5	19.0	11.0	--	12.0	3.0	--	--	--	--	4.0	--	11.0	--
Huntway Refining	09	CA	Wilmington	6.0	5.0	--	--	--	--	--	--	--	--	--	--	--	3.5	--	--	--
Lunday Thagard Co	09	CA	South Gate	7.4	7.5	--	--	--	--	--	--	--	--	--	--	--	2.4	--	--	--
Mobil Oil Corp	09	CA	Torrance	130.0	95.0	48.0	63.0	36.0	21.7	68.0	49.0	17.0	--	--	--	--	--	--	137.0	2.9
Paramount Petroleum	09	CA	Paramount	39.0	24.0	--	--	8.5	--	--	27.0	--	--	--	--	--	12.0	--	--	--
Powerine Oil Co	09	CA	Santa Fee Springs	49.0	26.0	10.0	12.5	10.0	8.0	19.5	17.0	2.8	--	1.5	--	--	--	--	19.0	0.6
Shell Oil Co	09	CA	Wilmington	139.0	75.0	53.0	42.0	24.0	--	11.0	96.0	8.6	--	--	--	--	--	--	36.0	2.5
Ten By Inc	09	CA	Oxnard	5.0	--	--	--	--	--	--	--	--	--	--	--	--	2.0	--	--	--
Texaco Refining	09	CA	Wilmington	100.0	54.0	75.0	30.0	39.0	26.0	30.0	37.0	6.3	--	--	--	--	--	--	63.0	2.0
Ultramar Inc	09	CA	Wilmington	72.0	42.0	24.0	38.0	14.5	--	42.0	15.0	10.5	--	9.0	--	--	--	--	--	1.2
Unocal Corp	09	CA	Los Angeles	111.0	83.0	20.0	47.0	52.0	27.5	--	90.0	10.0	--	--	--	--	--	--	49.4	--
				1,309.1	704.5	360.9	402.0	307.0	161.2	296.5	569.0	80.2	3.0	10.5	--	--	47.2	--	515.4	14.9
Anchór Refining	10	CA	McKittrick	11.0	7.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Kern Oil	10	CA	Bakersfield	22.0	--	--	--	3.0	--	--	4.5	--	--	--	--	--	--	--	--	--
San Joaquin	10	CA	Bakersfield	20.0	14.0	10.0	--	--	--	--	--	--	--	--	--	4.0	5.0	--	--	--
Sunland Refining	10	CA	Bakersfield	15.0	--	--	--	1.5	--	1.5	--	--	--	--	--	--	--	--	--	--
Texaco Refining	10	CA	Bakersfield	49.0	23.0	13.7	--	22.0	14.3	15.0	14.0	--	--	--	--	--	--	--	21.0	0.7
Witco Chemical	10	CA	Oildale	11.0	10.2	--	--	--	--	--	0.9	--	--	--	--	5.1	4.0	--	--	--
				128.0	54.2	23.7	--	26.5	14.3	16.5	19.4	--	--	--	--	9.1	9.0	--	21.0	0.7

Table B-10

ADDENDUM TO SECTION 1

U.S. CRUDE INTAKE QUALITY

BASE CASE 1990

Domestic Production

DOE Regions
PAD Districts

SUBSTANTIATING TABLES

U.S. DOMESTIC PRODUCTION BY DOE REGION
FROM PADD I, II, III, IV

DOE	STATE	NAME	API	SULFUR	DESTINATION DOE REGION 1	2	3	4	5	6	7	8	9	10	TOTAL
1	FL	Jay	51.6	0.26	--	--	--	--	16	--	--	--	--	--	16
1	PA	Bradford	35.0	0.30	12	2	--	--	--	--	--	--	--	--	14
3	KS	Eastern Kansas	36.6	0.34	--	--	152	--	--	--	--	--	--	--	152
3	OK	Amoco Sour-Cushing	32.1	2.00	--	85	69	--	--	--	--	--	--	--	154
3	OK	Cushing Sweet	39.4	0.42	--	--	154	--	--	--	--	--	--	--	154
2	ND	Williston	43.9	0.10	--	101	--	--	--	--	--	--	--	--	101
2	IL	Il. Basin	37.1	0.30	--	55	--	--	--	--	--	--	--	--	127
2	MI	Albion	39.7	0.27	--	54	--	--	--	--	--	--	--	--	54
5	AL	Citronelle	43.2	0.37	--	5	--	--	46	--	--	--	--	--	51
5	AR	Smackover	28.9	1.41	--	--	--	--	28	--	--	--	--	--	28
5	LA	LLS - Gibson	35.8	0.36	--	53	--	--	210	--	--	--	--	--	263
5	LA	Empire Mix	32.6	0.27	--	52	--	--	210	--	--	--	--	--	262
5	LA	Ostrica	35.0	0.26	--	53	--	--	210	--	--	--	--	--	263
5	LA	Eugene Island	34.0	0.91	--	53	--	--	210	--	--	--	--	--	263
5	MS	East Mississippi	37.4	1.10	--	7	--	--	67	--	--	--	--	--	74
5	NM	Lovington Blend	23.0	0.82	--	9	9	--	74	--	--	--	--	--	92
5	NM	E. Vacuum Unit	38.1	0.84	--	9	9	--	69	--	--	--	5	--	92
5	TX	East Texas Mix	55.4	0.17	--	--	35	--	202	--	--	--	--	--	50
5	TX	Gulf Coast Lt	38.1	0.05	--	--	--	--	200	--	--	--	--	--	200
5	TX	Hawkins	27.2	2.18	--	50	--	--	50	--	--	--	--	--	100
5	TX	Giddings	43.4	0.10	--	--	--	--	200	--	--	--	--	--	200
5	TX	Leveland	28.3	2.65	--	80	--	--	20	--	--	--	--	--	100
5	TX	No. Central Texas	43.9	0.10	--	50	--	--	50	--	--	--	--	--	100
5	TX	Refugio Heavy	23.8	0.19	--	--	--	--	200	--	--	--	--	--	200
5	TX	Rancho Sour	31.8	1.91	--	110	--	--	90	--	--	--	--	--	200
5	TX	Rancho WTI	40.5	0.35	--	298	119	--	385	--	--	--	--	--	802
6	MT	Cutbank	32.5	1.40	--	--	--	--	--	54	--	--	--	--	54
6	UT	Aneth	41.1	0.15	--	--	--	--	--	30	--	--	8	--	38
6	UT	Anchutz	52.5	0.02	--	--	--	--	--	38	--	--	--	--	38
6	CO	Rangely	33.6	0.58	--	--	--	--	--	83	--	--	--	--	83
6	WY	Wyoming Sweet	38.8	0.41	--	34	--	--	--	104	--	--	--	--	138
6	WY	Wyoming Sour	24.1	2.55	--	63	--	--	--	84	--	--	--	--	147
			PADD I, II, III, IV		12	1,223	547	--	2,537	393	--	--	12	--	4,610

Table B-11

U.S. DOMESTIC PRODUCTION BY DOE REGION
FROM PADD V

DOE	STATE	NAME	API	SULFUR	DESTINATION DOE REGION 1	2	3	4	5	6	7	8	9	10	TOTAL
7	AK	Alaskan No. Slope	27.7	1.12	--	17	101	733	219	--	186	--	486	--	1,742
7	AK	Cook Inlet Blend	34.2	0.13	--	--	--	--	--	--	31	--	--	--	31
10	CA	Elk Hills	34.9	0.43	--	--	--	8	--	--	--	--	24	47	79
10	CA	Kern River	13.1	1.21	--	--	--	56	--	--	--	--	48	17	121
10	CA	Lost Hills	30.2	0.56	--	--	--	7	--	--	--	--	7	4	18
10	CA	Yowlumni	30.7	0.61	--	--	--	5	--	--	--	--	5	3	13
8	CA	Santa Maria	13.0	5.90	--	--	--	--	--	--	--	3	--	--	3
8	CA	Cat Canyon	13.0	3.99	--	--	--	--	--	--	--	3	--	--	3
4	CA	San Ardo	14.2	1.92	--	--	--	--	--	--	--	2	3	6	11
9	CA	Wilmington THUMS	17.9	1.49	--	--	--	--	--	--	--	--	71	--	71
9	CA	Ventura Mix	27.8	1.10	--	--	--	--	--	--	--	--	18	--	18
9	CA	Long Beach	18.6	1.45	--	--	--	--	--	--	--	--	6	--	6
9	CA	Beta	16.4	3.40	--	--	--	--	--	--	--	--	15	--	15
9	CA	Huntington Beach	21.1	1.65	--	--	--	--	--	--	--	--	10	--	10
4	CA	Fruitvale	16.3	1.16	--	--	--	--	--	--	--	--	1	--	1
8	CA	Hondo	20.2	4.50	--	--	--	--	--	--	--	--	22	--	22
9	CA	SJV Blend	16.3	1.13	--	--	--	81	--	--	--	--	144	32	258
10	CA	Midway-Sunset	13.1	1.21	--	--	--	113	44	--	--	--	6	--	162
10	CA	So. Belridge Blend	16.8	1.09	--	--	--	105	36	--	--	--	9	--	150
6	NV	Eagle Springs	23.3	2.10	--	--	--	--	--	12	--	--	--	--	12
			PADD V		--	17	101	1,109	299	12	217	8	875	108	2,746
			Gravity, API		31.0	36.6	36.3	23.5	35.4	34.9	28.6	13.8	23.9	27.3	32.3
			Sulfur, Wt%		0.3	0.9	0.6	1.2	0.6	1.0	1.0	3.3	1.3	0.7	0.8

Figure B-12

U.S. DOMESTIC CRUDE PRODUCTION
1990

PADD	DOE	STATE	NAME	MB/D	API	% SULFUR
I	1	FL	Jay	16	51.6	0.26
I	1	PA	Bradford	14	35.0	0.30
				30	**43.9**	**0.28**
II	3	KS	Eastern Kansas	152	36.6	0.34
II	3	OK	Amoco Sour-Cushing	154	32.1	2.00
II	3	OK	Cushig Sweet	154	39.4	0.42
II	2	ND	Williston	101	43.9	0.10
II	2	IL	IL Basin	127	37.4	0.39
II	2	MI	Albion	54	39.7	0.27
				742	**37.6**	**0.69**
III	5	AL	Citronelle	51	43.2	0.37
III	5	AR	Smackover	28	28.9	1.41
III	5	LA	LLS - Gibson	263	35.8	0.36
III	5	LA	Empire Mix	262	32.6	0.27
III	5	LA	Ostrica	263	35.0	0.26
III	5	LA	Eugene Island	263	34.0	0.91
III	5	MS	East Mississippi	74	37.4	1.10
III	5	NM	Lovington Blend	92	23.0	0.82
III	5	NM	E. Vacuum Unit	92	38.1	0.84
III	5	TX	East Texas Mix	50	55.4	0.17
III	5	TX	Gulf Coast Lt	200	38.1	0.06
III	5	TX	Hawkins	100	27.2	2.18
III	5	TX	Giddings	200	43.4	0.10
III	5	TX	Leveland	100	28.3	2.65
III	5	TX	No. Central Texas	100	43.9	0.10
III	5	TX	Refugio Hvy	200	23.8	0.19
III	5	TX	Rancho Sour	200	31.8	1.91
III	5	TX	Rancho WTI	802	40.5	0.35
				3,340	**36.0**	**0.60**

Table B-13

U.S. DOMESTIC CRUDE PRODUCTION
1990
(Continued)

PADD	DOE	STATE	NAME	MB/D	API	% SULFUR
IV	6	MT	Cutbank	54	32.5	1.40
IV	6	UT	Aneth	38	41.1	0.15
IV	6	UT	Anchutz	38	52.5	0.02
IV	6	CO	Rangely	83	33.6	0.58
IV	6	WY	Wyoming Sweet	138	38.8	0.41
IV	6	WY	Wyoming Sour	147	24.1	2.55
				498	**34.1**	**1.13**
V	7	AK	Alaskan No. Slope	1,742	27.7	1.12
V	7	AK	Cook Inlet Blend	31	34.2	0.13
V	10	CA	Elk Hills	79	34.9	0.43
V	10	CA	Kern River	121	13.1	1.21
V	10	CA	Lost Hills	18	30.2	0.56
V	10	CA	Yowlumni	13	30.7	0.61
V	8	CA	Santa Maria	3	13.0	5.90
V	8	CA	Cat Canyon	3	13.0	3.99
V	4	CA	San Ardo	11	14.2	1.92
V	9	CA	Wilmington THUMS	71	17.9	1.49
V	9	CA	Ventura Mix	18	27.9	1.10
V	9	CA	Long Beach	6	18.6	1.45
V	9	CA	Beta	15	16.4	3.40
V	9	CA	Huntington Beach	10	21.1	1.65
V	4	CA	Fruitvale	1	16.3	1.16
V	8	CA	Hondo	22	20.2	4.50
V	10	CA	SJV Blend	258	16.3	1.13
V	10	CA	Midway-Sunset	162	13.1	1.21
V	10	CA	So. Belridge Blend	150	16.8	1.09
V	6	NV	Eagle Springs	12	23.3	2.10
				2,746	**24.3**	**1.16**

Table B-14

U.S. DOMESTIC CRUDE PRODUCTION
1990
SUMMARY

	VOLUME MB/D	API	% SULFUR
PADD I	30	51.6	0.26
PADD II	742	37.6	0.69
PADD III	3,340	36.7	0.60
PADD IV	498	34.1	1.13
PADD V	2,746	24.3	1.16
	7,356	**32.3**	**0.87**

Memo: NGL Available As Refinery Feedstock: 186 MB/D

Table B-15

ADDENDUM TO SECTION 1

U.S. CRUDE INTAKE QUALITY

BASE CASE 1990

Import Crudes

DOE Regions

PAD Districts

SUBSTANTIATING TABLES

CRUDE IMPORTS BY DOE PROFILE
BASE CASE 1990

API	SULFUR	NAME	PADD I DOE REGION 1	II 2	II 3	V 4	III 5	IV 6	V 7	V 8	V 9	V 10	TOTAL
39.6	0.36	Canadian Common	52.3	133.1	--	5.2	5.2	54.7	--	--	--	--	250.6
23.8	1.88	Lloydminster	7.4	376.7	--	5.8	2.5	--	--	--	--	--	392.4
34.6	0.14	Bonny Light	244.4	121.1	--	--	246.6	--	--	--	--	--	612.1
28.5	0.17	Forcados	203.8	5.1	--	--	50.9	--	--	--	--	--	259.8
31.2	0.20	Cabinda	61.1	--	--	--	91.7	--	--	--	--	--	152.8
41.4	0.11	Zarzaitine	67.0	15.8	--	--	96.5	--	--	--	0.9	--	180.3
37.2	0.40	Brent	67.9	27.1	17.6	--	138.4	--	--	--	--	--	251.0
32.8	1.88	Arab Light	40.6	81.2	--	5.9	507.3	--	--	--	--	--	635.0
31.1	2.50	Arab Medium	70.2	53.3	--	--	203.1	--	--	--	--	--	326.6
27.6	2.84	Arab Heavy	81.2	--	--	--	152.2	--	--	--	--	--	233.4
33.9	2.17	Basrah	43.9	39.9	--	4.7	349.0	--	--	--	--	--	437.4
36.1	1.89	Kirkuk	30.6	25.2	15.4	4.8	154.6	--	--	--	--	--	230.6
21.8	3.24	Maya	31.3	16.1	--	3.9	254.3	--	--	--	--	--	305.6
34.0	1.43	Isthmus	43.1	71.6	--	10.4	258.2	--	--	--	--	--	383.4
13.3	2.36	Bachaquero 13	36.7	--	--	1.2	23.5	--	--	--	--	--	61.4
17.0	2.62	Bachaquero 17	63.8	--	--	--	90.5	--	--	--	--	--	154.3
23.7	1.85	Bachaquero 24	33.0	--	--	--	378.8	--	--	--	--	--	411.7
32.1	1.10	Tia Juana Light	13.3	4.4	--	6.3	14.6	--	--	--	--	--	38.6
29.1	0.52	Cano Limon	47.9	41.1	--	3.4	174.2	--	1.9	--	0.5	--	269.0
39.5	0.07	Challis	32.2	6.5	--	33.3	32.7	--	18.5	--	157.8	--	281.0
		DOE, MBCD	1,272	1,018	33	85	3,225	55	20	--	159	--	5,867
		Average Gravity, API	31.0	30.6	36.7	34.4	31.1	39.6	38.5	--	39.5	--	31.4
		Average Sulfur, Wt%	1.1	1.4	1.1	1.0	1.6	0.4	0.1	--	0.1	--	1.4

Table B-16

IMPORTED CRUDES TO USA BY SOURCE
BASE CASE 1990

SOURCE NAME	PADD I	PADD II	PADD III	PADD IV	PADD V	TOTAL MBCD
Canada	59.7	509.8	7.7	54.7	11.0	643.0
Nigeria	410.3	122.9	250.9	--	--	784.0
Angola	95.8	1.5	138.7	--	--	236.0
Other North & West Africa	68.8	16.2	99.0	--	0.9	185.0
North Sea	67.9	44.7	138.4	--	--	251.0
Saudi Arabia	192.0	134.4	862.7	--	5.9	1,195.0
Other Mid-East	74.5	80.5	503.6	--	9.5	668.0
Mexico	74.4	87.8	512.5	--	14.3	689.0
Venezuela	146.8	4.4	507.3	--	7.5	666.0
Other South America	47.9	41.1	174.2	--	5.8	269.0
Pacific Basin	32.2	6.5	32.7	--	209.6	281.0
	1,272	1,051	3,225	55	264	5,867

Table B-17

IMPORTED CRUDES TO USA BY QUALITY
BASE CASE 1990

API	SULFUR	CRUDE NAME	PADD I	PADD II	PADD III	PADD IV	PADD V	TOTAL
39.6	0.36	Canadian Common	52.3	133.1	5.2	54.7	5.2	250.6
23.8	1.88	Lloydminster	7.4	376.7	2.5	--	5.8	392.4
34.6	0.14	Bonny Light	244.4	121.1	246.6	--	--	612.1
28.5	0.17	Forcados	203.8	5.1	50.9	--	--	259.8
31.2	0.20	Cabinda	61.1	--	91.7	--	--	152.8
41.4	0.11	Zarzaitine	67.0	15.8	96.5	--	0.9	180.3
37.2	0.40	Brent	67.9	44.7	138.4	--	--	251.0
32.8	1.88	Arab Light	40.6	81.2	507.3	--	5.9	635.0
31.1	2.50	Arab Medium	70.2	53.3	203.1	--	--	326.6
27.6	2.84	Arab Heavy	81.2	--	152.2	--	--	233.4
33.9	2.17	Basrah	43.9	39.9	349.0	--	4.7	437.4
36.1	1.89	Kirkuk	30.6	40.6	154.6	--	4.8	230.6
21.8	3.24	Maya	31.3	16.1	254.3	--	3.9	305.6
34.0	1.43	Isthmus	43.1	71.6	258.2	--	10.4	383.4
13.3	2.36	Bachaquero	133.5	--	182.0	--	2.4	317.9
32.1	1.10	Tia Juana Light	13.3	4.4	325.3	--	5.1	348.1
29.1	0.52	Cano Limon	47.9	41.1	174.2	--	5.8	269.0
39.5	0.07	Challis	32.2	6.5	32.7	--	209.6	281.0
			1,272	1,051	3,225	55	264	5,867
		Vol. Average API	30.73	30.83	31.12	39.60	37.77	31.37
		Vol. Average Sulfur	1.025	1.355	1.597	0.360	0.377	1.363

Table B-18

SECTION 2

FORECASTED CRUDE SUPPLIES
(Assuming No Incremental U.S. Heavy Crude)

This section offers the views of Bonner & Moore on what the future holds for the U.S. refining industry should the incremental domestic heavy crude not become available as indicated by the DOE. The forecasted crude supplies are consistent with all premises used throughout **Appendix A, Petroleum Market Evaluation.**

Once again, 1990 was used as a starting point; therefore, all breakdowns of crude by sources and qualities correspond to the details presented in the previous section of this same appendix.

The most important highlights governing the availability of crude to the United States under this "no new incremental heavy crudes" scenario during the next two decades are as follows (**Table B-19**):

- Declining U.S. domestic crude production is exacerbated in Region 7, where ANS availability declines approximate 80/90 MB per year during the period under study. Available heavier crudes in Regions 4, 8, 9, and 10 show a modest 5 MB per year production decline. Overall, U.S. domestic production declines about 2% per year during the planning period.

  The total balance of U.S. crude supplies indicates that 1996 will be the year in which more than 50% of the refinery crude slate will depend on imports. Beyond the year 2000, the proportion of crude imports exceeds two-thirds of the refinery intake needs (**Figure B-2**).

- Undoubtedly, the Middle East producing area will be the main incremental supplier of import crude to the U.S. refineries during the next decades, followed by South America in terms of mainly medium quality crudes (mix of heavy and light crudes (**Figure B-3**).

- Despite the plentiful heavy oils anticipated to be produced in South America, volumes similar to those seen up to 1990 are expected to find their way into the U.S. refineries. Regions 1 and 5 seem to be the traditional recipients of these imports (**Figure B-4**).

  Heavy crude imports, as defined in the study, are less than 4% of the total crude import volumes. The quality of these imports suggests a specialties disposition (asphalt) rather than feed to a conversion unit for the production of quality refined products.

- Forecasted crude intake gravities for the overall U.S. refinery system show a crude slate with an average gravity of approximately 32° API, and crude intake sulphur quality deteriorates during the next decade, as mainly Middle Eastern crudes replace declining domestic production (**Figures B-5 and B-6**).

Tables substantiating the figures used for our crude quality and geographical distribution forecasts are shown at the end of this section.

U.S. FORECASTED CRUDE SUPPLIES
(No Incremental Heavy Oil)

(MB/D)				1990	1995	2000	2005	2010
DOMESTIC								
PADD	**Region**	**API**	**%S**					
I	East Light	51.6	0.26	30	20	10	–	–
II/IV	Ok/Wyo	36.7	0.87	1,240	1,170	1,120	1,070	1,020
III	Tx/Lou	36.7	0.60	3,340	3,129	2,830	2,486	2,216
V	Alaska	27.8	1.12	1,773	1,490	1,070	660	400
	Continent	18.3	1.33	973	948	923	898	873
	Total U.S.			**7,356**	**6,757**	**5,953**	**5,114**	**4,509**
			API	**32.3**	**32.3**	**32.4**	**32.5**	**32.5**
			%S	**0.87**	**0.87**	**0.86**	**0.86**	**0.85**
IMPORTS								
	Region	**API**	**%S**					
	N. America	29.8	1.29	643	640	640	640	640
	S. America	24.8	2.20	1,624	1,805	2,055	2,255	2,425
	Mid East	32.9	1.80	1,863	2,444	3,558	4,609	5,418
	Africa	35.4	0.17	1,205	1,100	900	900	900
	Europe	37.6	0.40	251	230	220	200	200
	Asia	39.5	0.10	281	280	230	210	210
	Total Imports			**5,867**	**6,499**	**7,603**	**8,814**	**9,793**
			API	**31.4**	**31.2**	**31.0**	**31.1**	**31.2**
			%S	**1.38**	**1.46**	**1.58**	**1.63**	**1.65**
	TOTAL CRUDE			**13,223**	**13,256**	**13,556**	**13,928**	**14,302**
			API	**31.9**	**31.8**	**31.7**	**31.6**	**31.6**
			%S	**1.10**	**1.16**	**1.26**	**1.34**	**1.40**

Table B-19

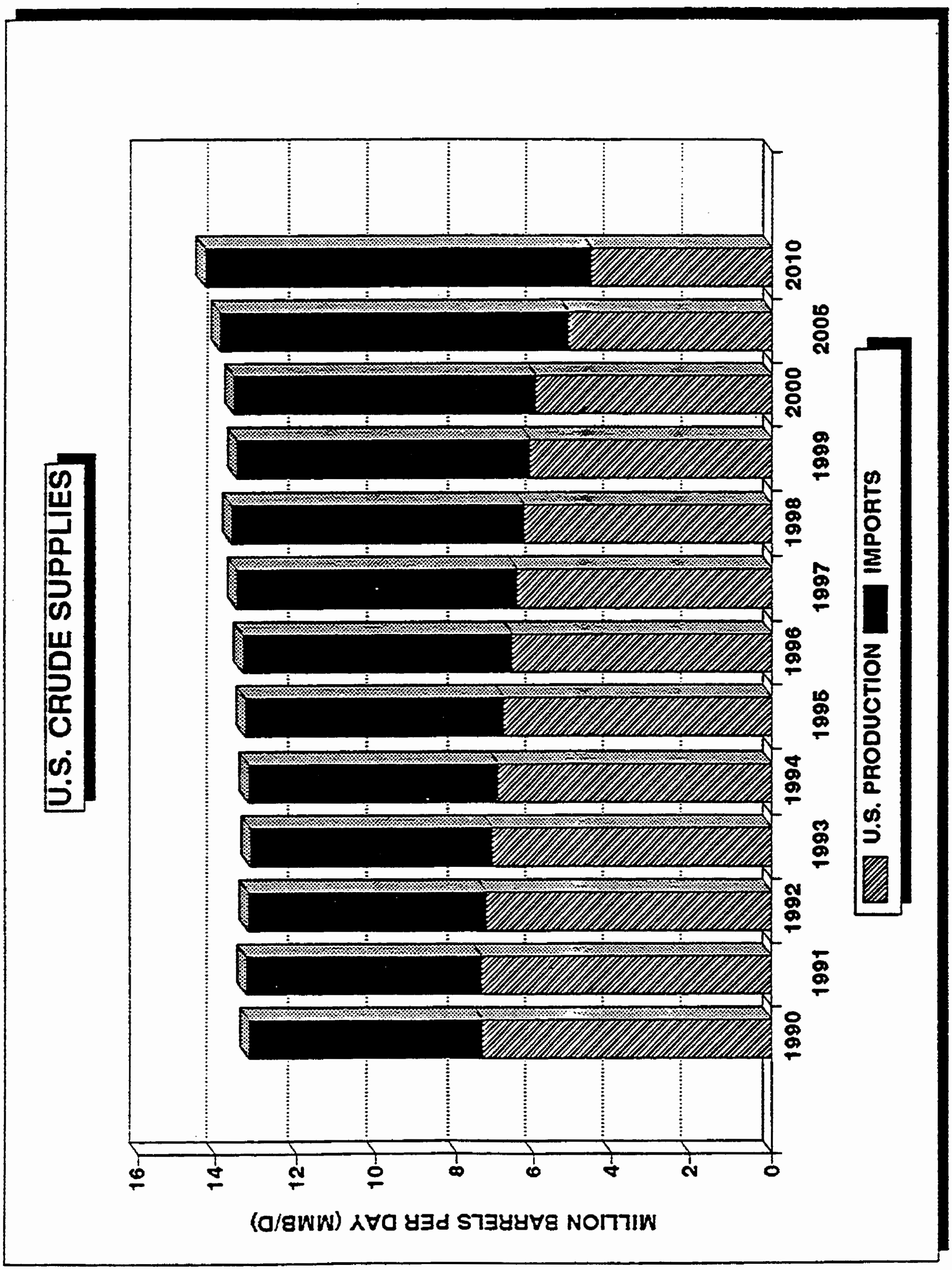

U.S. CRUDE SUPPLIES
MILLION BARRELS PER DAY (MMB/D)
0
2
4
6
8
10
12
14
16
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2005
2010
U.S. PRODUCTION
IMPORTS

Figure B-2

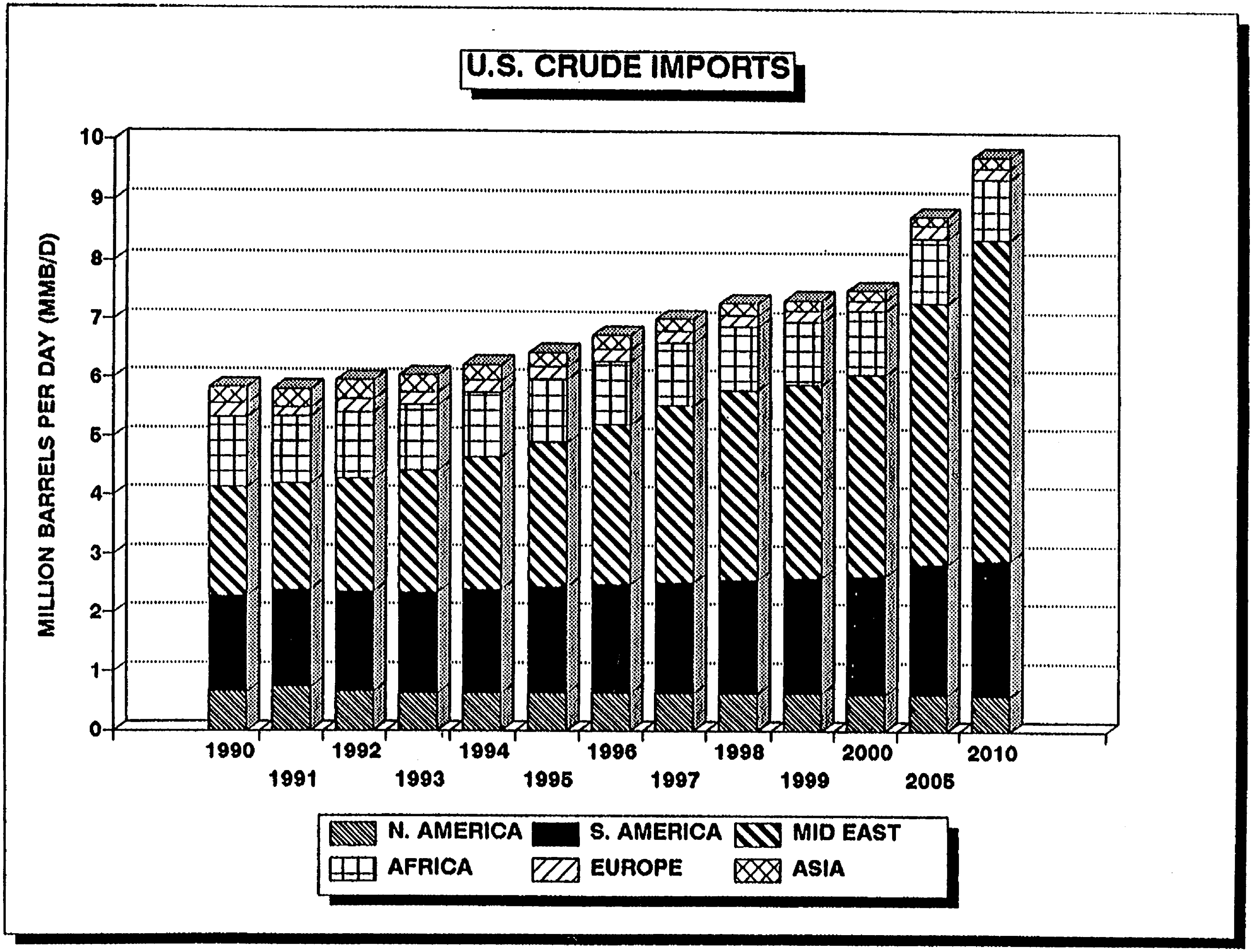
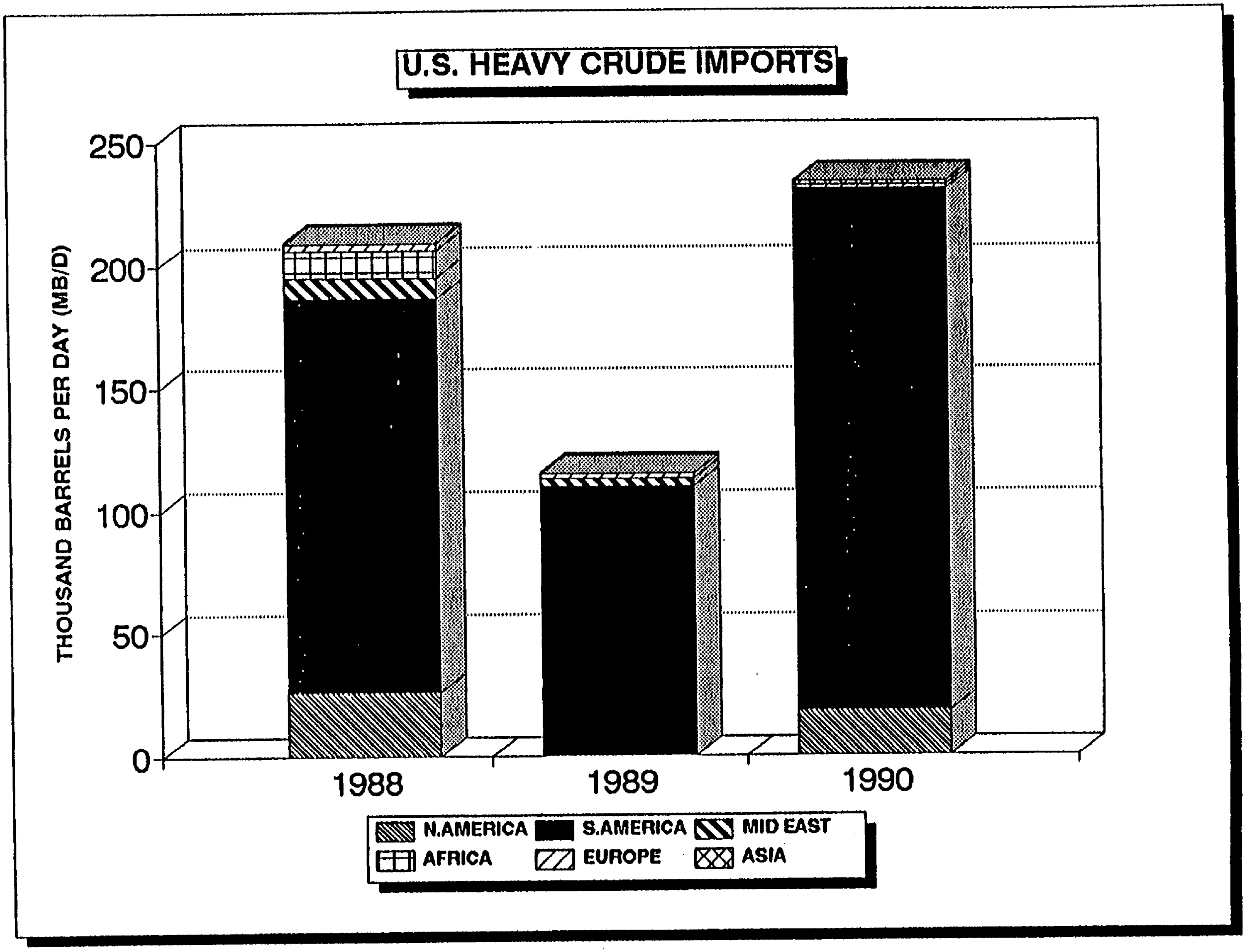

U.S. CRUDE IMPORTS
MILLION BARRELS PER DAY (MMB/D)
0
1
2
3
4
5
6
7
8
9
10
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2005
2010
N. AMERICA
S. AMERICA
MID EAST
AFRICA
EUROPE
ASIA

Figure B-3



U.S. HEAVY CRUDE IMPORTS
THOUSAND BARRELS PER DAY (MB/D)
250
200
150
100
50
0
1988
1989
1990
N.AMERICA
S.AMERICA
MID EAST
AFRICA
EUROPE
ASIA

Figure B-4

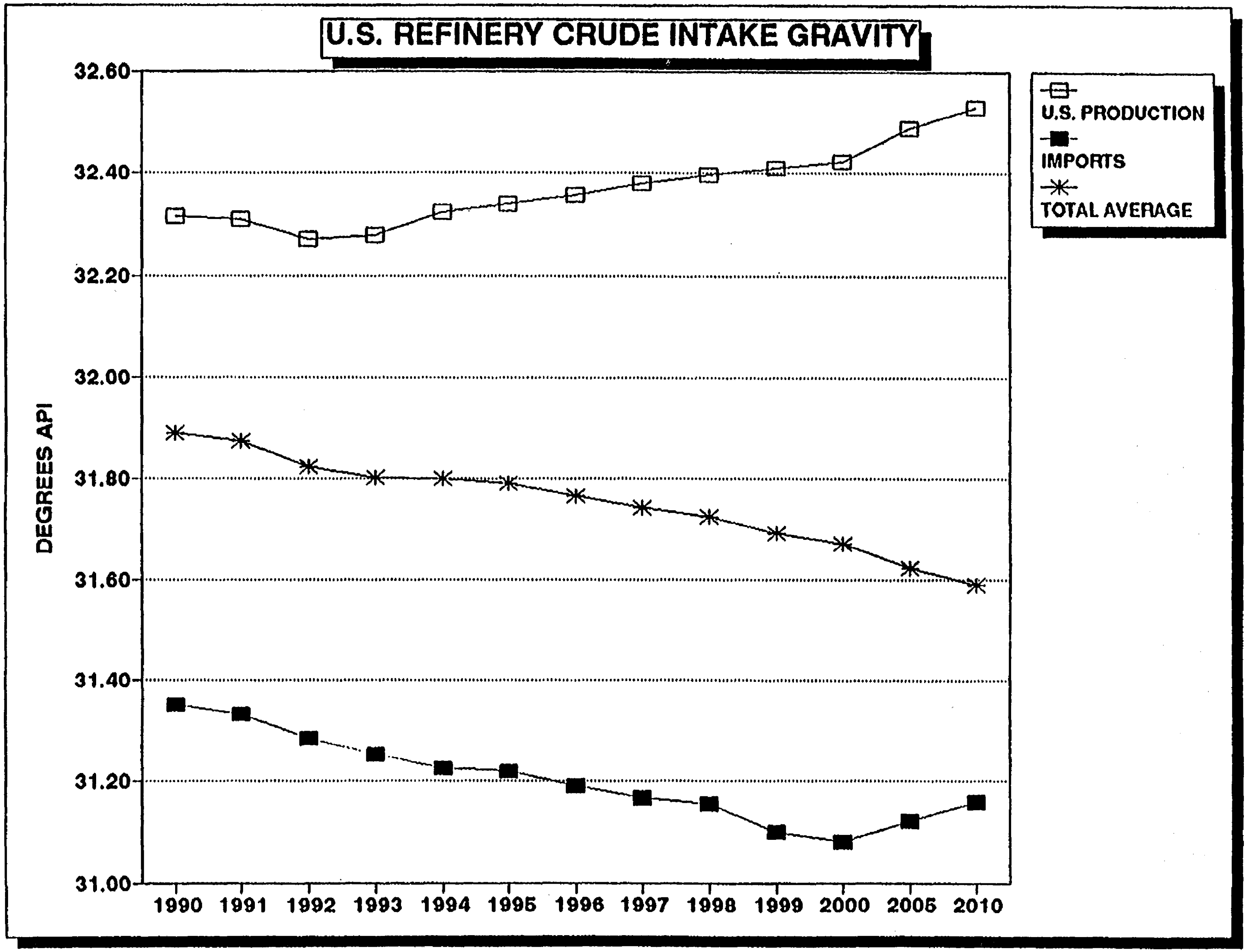

U.S. REFINERY CRUDE INTAKE GRAVITY
DEGREES API
32.60
32.40
32.20
32.00
31.80
31.60
31.40
31.20
31.00
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2005
2010
U.S. PRODUCTION
IMPORTS
TOTAL AVERAGE

Figure B-5

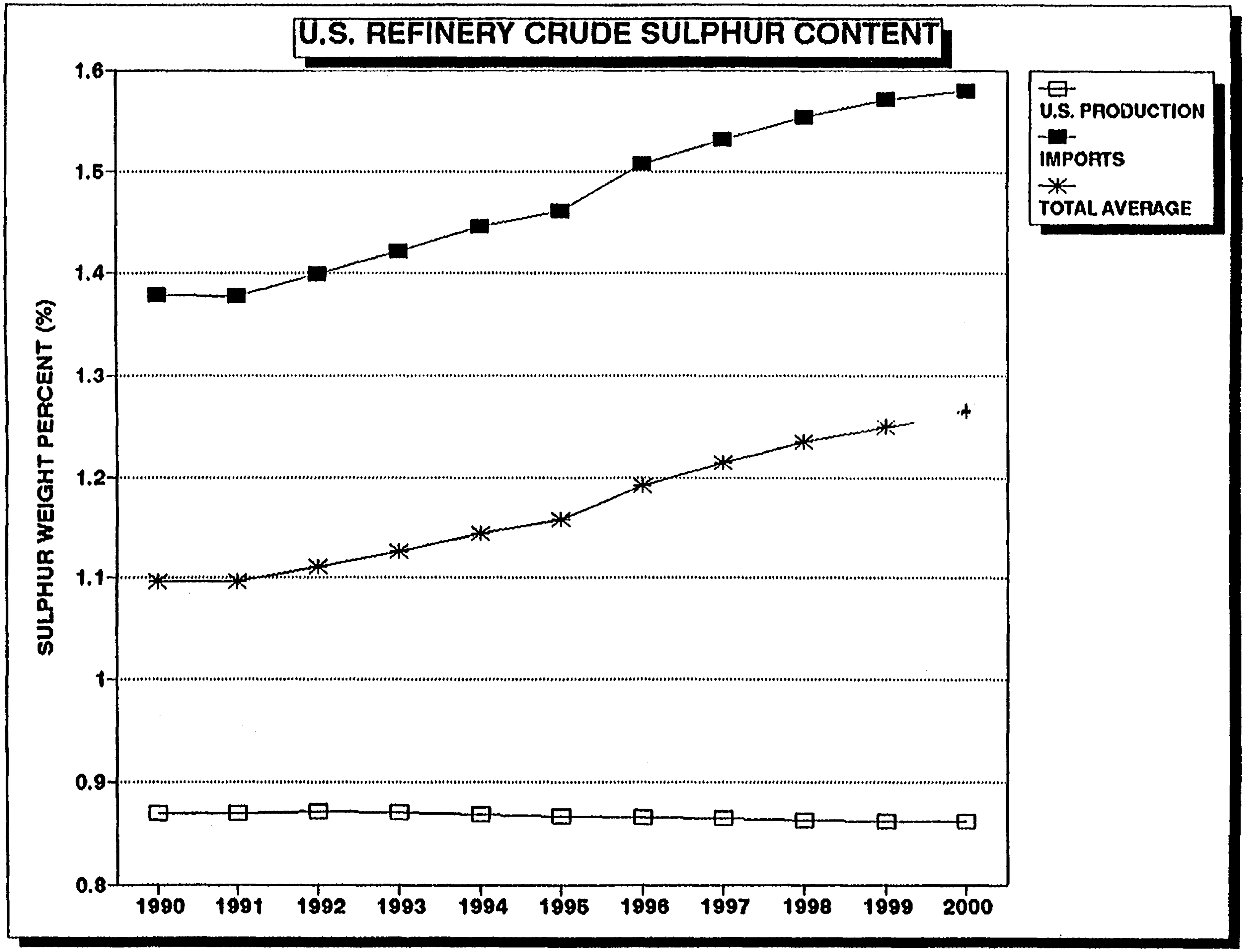

U.S. REFINERY CRUDE SULPHUR CONTENT
SULPHUR WEIGHT PERCENT (%)
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
U.S. PRODUCTION
IMPORTS
TOTAL AVERAGE

Figure B-6

U.S. CRUDE IMPORTS[1]

	1986	1988	1990	1991 (Est)
NORTH AMERICA				
Canada	570	682	643	739
	570	682	643	739
SOUTH AMERICA				
Mexico	620	625	689	775
Venezuela	416	440	666	627
Other	230	217	269	279
	1,266	1,282	1,624	1,681
MIDDLE EAST				
Saudi Arabia	618	888	1,195	1,761
Iraq	81	344	514	–
UAE	38	22	9	–
Iran	20	–	–	16
Kuwait	28	80	79	–
Others	28	64	66	30
	813	1,398	1,863	1,807
AFRICA				
Algeria	78	58	58	60
Angola	103	204	236	243
Cameroon	38	38	13	15
Nigeria	437	608	784	728
Others	82	100	114	121
	738	1,008	1,205	1,167
EUROPE				
Norway	53	62	96	71
United Kingdom	316	254	155	93
	369	316	251	164
ASIA				
Indonesia	296	186	98	114
Others	78	183	183	217
	374	369	281	331
TOTAL	4.130	5,055	5,867	5,889

(1) Excludes imports for the SPR

Table B-20

U.S. HEAVY CRUDE IMPORTS
1990

Country	Crude	Region	Gravity	% Sulphur	Volumen, MBD
Italy	Rospo Nave	1	11.9	4.7	1.8
Venezuela	Bachaquero	1	17.0	2.4	63.8
	Boscan	1	10.0	5.5	11.4
	Pilon	1	13.0	2.0	23.5
Total Region 1			**15.2**	**2.7**	**100.5**
Canada	Cold Lake	2	13.2	4.1	15.0
Total Region 2			**13.2**	**4.1**	**15.0**
Canada	Cold Lake	5	13.2	4.1	2.4
Indonesia	Bima	5	20.0	0.2	1.6
Venezuela	Bachaquero	5	13.0	2.7	14.1
	Bachaquero	5	17.0	2.5	44.1
	Bachaquero	5	20.0	2.0	2.8
	Laguna	5	10.9	2.7	1.6
	Merey	5	17.0	2.3	38.9
	Pilon	5	13.2	2.3	9.4
	Boscan	5	10.2	5.5	3.1
Total Region 5			**16.0**	**2.5**	**118.0**
Venezuela	Boscan	9	10.0	5.5	1.2
Total Region 9			**10.0**	**5.5**	**1.2**
TOTAL U.S.			**15.4**	**2.7**	**234.7**

No Heavy Crude Imports To Other Regions

Table B-21

TABLE OF CONTENTS

APPENDIX C
REPRESENTATIVE REGIONAL LP MODEL

SECTION 1
APPROACH AND METHODOLOGY

SECTION 1

APPROACH AND METHODOLOGY

An understanding of approach, premises, and assumptions is important in judging the applicability of results from any study and in appreciating its inherent strengths and limitations. This section describes the linear programming approach taken by Bonner & Moore Management Science in estimating the refining industry costs associated with increasing the production of heavy crude oil in the United States. Descriptions are also provided for the major study premises and assumptions.

In conducting this study, we made extensive use of Bonner & Moore's Refinery and Petrochemical Modeling System **RPMS(R)2000**, as well as Bonner & Moore's **ASSAY 2000TM** crude evaluation and selection system.

THE RPMS(R)2000 SYSTEM

RPMS 2000 is the industry standard for applying linear programming techniques to production planning in the worldwide refining industry. The system contains the most powerful modeling techniques and capabilities available to refining industry planners. RPMS 2000 was developed in response to industry demands for a full-capability modeling system.

RPMS 2000 is in wide use for various purposes, including the following:

- Crude oil and raw materials evaluation and selection
- Evaluation of capital investments in processing equipment
- Assessment of new technology
- Competitive analysis and market evaluations.

The basic RPMS 2000 processor contains programs written for rapid assembly and solution of process plant models, using a combination of user modeling premises, RPMS 2000 databases, and user-supplied data. It also includes recursion capabilities for management of non-linearities, such as pooling.

The system's refining database provides a comprehensive selection of submodels and investment/capacity relationships for most commercially available processes in use by the world refining industry. Process submodels reflect the advanced modeling techniques developed by Bonner & Moore across more than 30 years. This database also contains blending data for gasoline, middle distillates, and fuel oils and quality information for most refinery streams.

THE ASSAY 2000™ SYSTEM

With Bonner & Moore's ASSAY 2000™ system, and its associated database, the user can specify crudes or blends of crudes which will be used in the model. Crude assay data are transferred automatically within RPMS 2000 to support crude-dependent yield and quality calculations. Thus, model data are automatically updated as new cut-points for crude distillation are provided by the user or computed by the system.

BASIS FOR MODEL CONFIGURATION

Estimates of the added costs associated with refining increased amounts of heavy crude oil were determined by preparing mathematical (linear programming) models of each of ten regions of the United States. Of these ten regions, Region 5 consists of the U.S. Gulf Coast, and is the major crude oil producing and refining region in the country. Therefore, the basic mathematical model was calibrated against 1990 published data for this region.

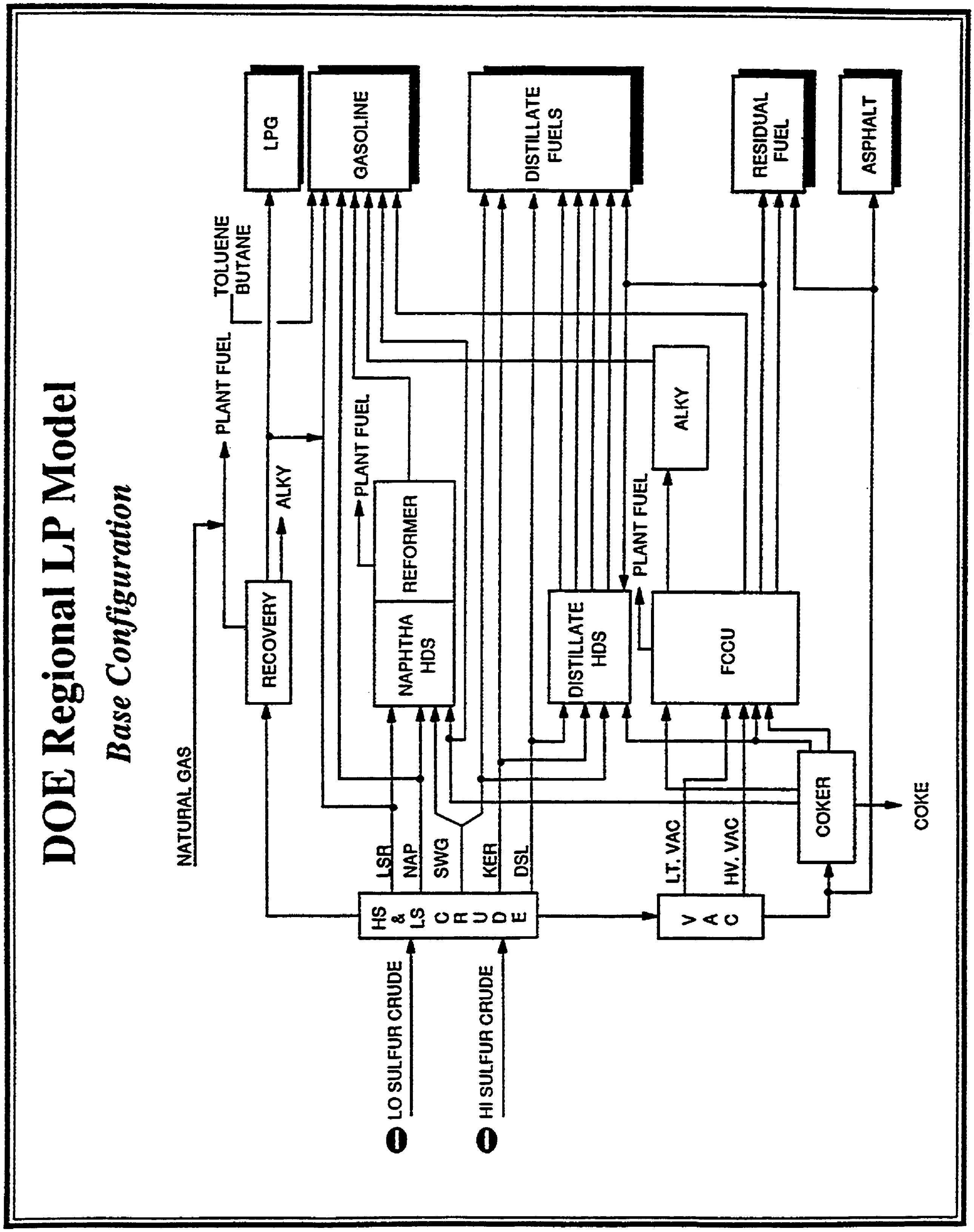
A schematic of the base refinery model is shown in **Figure C-1**. This type of refinery already has capacity to upgrade heavy crude oils by thermal, catalytic, and hydrogen cracking technologies. Each region of the US has these technologies but in different ratios.

Models of the other individual regions are, then, modifications of that for Region 5, each with their own respective process configuration, crude supply quality, product quality distribution. Supply scenarios for the years 1990, 1995, 2000, 2005, and 2010 were evaluated.

Crude oil availability for all regions was based on actual 1990 domestic production and import data. From the hundreds of individual crudes produced, a representative composite of 11 domestic and 7 foreign crudes was used for the models; their respective volumes and quality closely approximate the average gravity of crude oil charged during 1990 as reported to the U.S. government. Pipeline and marine movements of crudes from production areas to various refining centers are recognized.

Given a fixed availability of crudes for each case, the models were required to produce a complete spectrum of products consistent with the anticipated volume growth and quality changes for the respective year. The impact of the Clean Air Act for motor gasolines and highway diesel fuels is recognized.

To avoid unrealistic solutions or mathematical problems, the models have the option of purchasing (i.e., importing from another region or offshore) material at the forecasted prices for the respective year. Through its new investment feature, RPMS 2000 allows additional processing capacity to be provided at a cost. This cost recognizes all of the various operating and financial factors associated with the respective process. The financial factors recognize a 15% cost of capital, a 13-year economic and depreciable life, and a marginal tax rate of 34%. These new facilities are built on a **stream-day** basis, which differs from the LP models' use of **calendar-day** by an accepted factor. Typical LP results for Region 5 are shown in at the end of this section.



DOE Regional LP Model
Base Configuration
NATURAL GAS
PLANT FUEL
TOLUENE
BUTANE
LPG
GASOLINE
DISTILLATE FUELS
RESIDUAL FUEL
ASPHALT
RECOVERY
ALKY
PLANT FUEL
NAPHTHA HDS
REFORMER
DISTILLATE HDS
PLANT FUEL
FCCU
ALKY
COKER
COKE
LSR
NAP
SWG
KER
DSL
HS & LS CRUDE
LT. VAC
HV. VAC
VAC
LO SULFUR CRUDE
HI SULFUR CRUDE

Figure C-1

RPMS 2000 RUNS
REGION 5
BASE CASE 1990
SUBSTANTIATING TABLES

ELEMENT PEEK

SUMMARY REPORT . . .

CASE = FIVE90 (.) VOL BALANCE CLOSURE = -19.383
ITERATION NUMBER = 1820 WGT BALANCE CLOSURE = 0.
OBJECTIVE VALUE = 82869.281 (82869.281) MAXINV = 0.

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
VOLUME BASIS PURCHASES . . .						
JAY	EAST LIGHT	15,000	15,000	15,000	0.	25.701
CSM	CUSHING SWEET	297,000	297,000	297,000	0.	25.442
WSO	MID WEST SOUR	0	0	0	0.	24.165
ATR	MID WEST HVY	0	0	0	0.	23.155
BOO	ROCKY MTN HVY	0	0	0	0.	23.581
RWT	WEST TEXAS INT	652,000	652,000	652,000	0.	25.692
GIB	LOUISIANA SWEET	1393,000	1393,000	1393,000	0.	26.137
BLV	GULF COAST HVY	49,000	49,000	49,000	0.	24.319
ANS	Alaska North Slope	339,000	339,000	339,000	0.	24.434
SSB	CALIFORNIA MED	0	0	0	0.	25.774
KES	CALIFORNIA HVY	0	0	0	0.	23.269

	DOMESTIC CRUDE	2745,000				
LOY	CANADIAN BLEND	7,000	7,000	7,000	0.	23.747
BCF	SO. AMERICAN MED	1042,000	1042,000	1042,000	0.	23.613
B17	SO. AMERICAN HVY	110,000	110,000	110,000	0.	22.744
ARL	MIDDLE EAST	1358,000	1358,000	1358,000	0.	24.936
BON	AFRICAN	660,000	660,000	660,000	0.	25.985
BSX	EUROPE	138,000	138,000	138,000	0.	25.547
CHA	ASIA	0	0	0	0.	26.867

	IMPORTS	3315,000				
C2S	Ethane	0	0	0	-8.190	-3.245
C3S	Propane	0	0	98,000	-14.000	-4.000
IC4	Iso Butane	81,661	0	200,000	-20.000	
NC4	Normal Butane	137,356	0	200,000	-18.000	
TOL	Purchased octane	0	0	100,000	-50.000	-11.062
MTB	MTBE	0	0	63,000	-49.000	
ETL	Ethanol	0	0	0	-25.620	12.957
MTL	Methanol	0	0	0	-23.800	115.033

	OTHER FEEDSTOCK	219,017				
		========				
	TOTAL	6279,018				
WEIGHT BASIS SALES . . .						
COK	Coke	25,689	0		5.000	
C2U	Ethylene	0	0	0	0.	-243.025

Table C-1

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
WEIGHT BASIS SALES (CONTINUED)						
PPY	Propylene Mix	0	0	0	0.	
BDU	Butadiene	0	0	0	0.	-441.135
SC4	Stm Crackr Butenes	0	0	0	0.	-358.553
LSA	WT LOSS & ADJ	0			0.	
	TOTAL	25,689				
VOLUME BASIS SALES . . .						
MRG	Regular Leaded	66,578	66,578	66,578	0.	-30.290
MUR	Unleaded Regular	2090,081	0		29.530	
MUI	Unleaded Midgrade	367,000	367,000	367,000	0.	-30.340
MUP	Unleaded Premium	489,000	489,000	489,000	0.	-31.556
MOR	O3 non-att Regular	0	0	0	0.	-20.630
MOP	O3 non-att Premium	0	0	0	0.	-19.683
MCR	CO non-att Regular	0	0	0	0.	-21.210
MCP	CO non-att Premium	0	0	0	0.	-21.210
MBR	Oxy Fuel+ Reform R	0	0	0	0.	-19.683
MBP	Oxy Fuel+ Reform P	0	0	0	0.	-21.210
GUR	Regular + Ethanol	0	0	0	0.	-30.435
GOR	O3 na Regular+ethl	0	0	0	0.	-22.425
GCR	CO na Regular+ethl	0	0	0	0.	-22.947
	TOTAL GASOLINE	3012,659				
AVG	Aviation Gasoline	13,584	13,584	13,584	0.	-32.875
JP4	JP4 Jet	96,532	96,532	96,532	0.	-28.755
	TOTAL AV NAPHTHA	110,115				
JTA	Aviation Jet Fuel	649,225	649,225	649,225	0.	-28.548
KER	Kerosene	18,567	18,567	18,567	0.	-27.418
N2D	Diesel	868,995	0		27.430	
N2O	Heating Oil	391,000	391,000	391,000	0.	-27.418
	TOTAL DISTILLATE	1927,786				
LS6	LOW Sulf FO <0.3%	32,000	32,000	32,000	0.	-26.068
MS6	MED Sulf FO <1.0%	75,000	75,000	75,000	0.	-22.226
HS6	HI Sulfur FO 3.0%	255,000	255,000	255,000	14.460	-7.103
BKR	Bunker Fuel 4.0%	0	0	0	0.	0.234
	TOTAL FUEL OIL	362,000				
LVN	Petrochem Naphtha	104,814	104,814	104,814	0.	-22.291
PCO	Petrochem Other	109,000	109,000	109,000	0.	-27.485
NPH	Spec Naphtha	33,197	33,197	33,197	0.	-22.304
LWX	Lubes + Waxes	111,268	111,268	111,268	0.	-28.258
ASP	Asphalt	111,962	111,962	111,962	0.	-20.263
BNZ	Benzene	44,000	44,000	44,000	0.	-65.051

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
VOLUME BASIS SALES (CONTINUED)						
TOL	Purchased octane	26,000	26,000	26,000	0.	-38.938
XYL	Xylene	58,000	58,000	58,000	0.	-67.668
HAR	HEAVY AROMATICS	0	0	0	0.	-33.044
LPG	Liq Pet Gas	207,257	0	291,000	10.000	
	TOTAL MISC.	805,498				
PGF	Plant Fuel Gas	204,764	0		0.	
PRF	Resid Plant Fuel	3,000	3,000	3,000	0.	-5.003
	PLANT FUEL & FLARE	207,764				
LOS	VOLUME LOSS	-268,242			0.	
	TOTAL	6157,580				
UTILITY PURCHASES . . .						
C82	CAT/CHEM DOLLARS	1351,996	0		-1.210	
TEL	TEL G-GL/BBL	6,658	0		-0.980	
FUL	PLT FUEL MM-BTU	1710,921	0		-1.850	
KWH	ELECTRIC KWH	0	0	0	-0.050	-0.020
OXN	OXYGEN TONS	0	0		-100.000	
PPP	POOL ERR TOTAL	0	0		-10.000	
H2O	COOL H2O M-GAL	0	0	0	0.	0.113
STM	STEAM M-LB	0	0	0	0.	2.490
WAT	PROC H2O M-GAL	0	0	0	0.	0.076
PWR	PWR GEN KWH	0	0	0	0.	0.030
UTILITY SALES . . .						
SUL	SULFUR TONS	4,823	0		70.000	
NEW FACILITIES . . .						
CRD	Crude Distillation	0	0	0	-1.091	-1.091
VAC	Vacuum Unit	0	0	0	-1.193	1.170
CKD	Delayed Coker Drum	0	0	0	-119.515	-119.515
CKV	COKER CHARGE	0	0	0	-3.115	-3.115
VBR	Visbreaker	0	0	0	-2.838	-2.838
HOL	Resid Hydrocracker	0	0	0	-15.543	-10.268
HOC	HOC @5 %FCC + RCC	0	0	0	-7.876	-7.876
FCC	Cat Cracker	0	0	0	-6.325	-6.325
HGO	Hy Gas Oil H2 Trtr	0	0	0	-4.724	-4.724
DSL	Lt Gas Oil H2 Trtr	0	0	0	-3.352	-3.352
HCK	Hydrocracker	0	0	0	-11.020	-6.309
VHK	Vacuum R/R HOL/RHT	0	0	0	-1.416	-1.416
HKT	Resid Hydrotreater	0	0	0	-10.165	-8.891
H2F	Naphtha H2 Treater	0	0	0	-2.772	-2.772
RGL	HP Cat Ref - Mogas	0	0	0	-5.427	-5.427

NIPER HEAVY OIL REFINING STUDY   CASE = FIVE90 , ITER = 1820, OBJ VALUE = 82869.28   300. 1.

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
NEW FACILITIES (CONTINUED)						
ALK	Alkylation	0	0	0	-10.890	-4.086
CPL	Cat Poly	0	0	0	-5.844	-1.773
ISM	C5+ Isomerization	0	0	0	-6.710	-5.205
IS4	C4 Isomerization	0	0	0	-7.518	-6.875
BDH	C4 De Hydrogenatio	0	0	0	-18.467	-18.350
MBE	MethylTert But Eth	0	0	0	-35.436	-35.436
EBE	Ethyl Tert But Eth	0	0	0	-35.436	-13.723
TAM	Tert Amyl Meth Eth	0	0	0	-35.436	-35.436
H2M	Stm Ref (H2-MSCF)	0	0	0	-1.526	-1.526
H2P	Cryogenic	0	0	0	-0.741	-0.741
OXI	Partial Oxidation	0	0	0	-2.408	-2.408
SUL	Sulfur Recovery	0	0	0	-696.059	-696.059
AC5	Cat C5 splitter	0	0	0	-0.847	-0.847
SPT	UnsatGaso Splitter	0	0	0	-0.485	-0.485
PWR	Power Generatn kVa	0	0	0	-1.125	-1.125
H2O	Cooling Water	0	0	0	-0.231	-0.231
MRX	Merox Treaters	0	0	0	-0.876	-0.876
STM	Boiler House	0	0	0	-0.100	-0.100
KWH	Power Distribution	0	0		-0.651	-0.651
WAT	Water Treatment	0	0		-1.352	-1.352
RAL	Low Pres Arom Ref	0	0	0	-5.395	6.370
BNZ	Benzene Tower	0	0	0	-1.455	-1.455
TOL	Toluene Tower	0	0	0	-1.533	-1.533
XYL	Xylene Tower	0	0	0	-1.480	-1.480
EXT	Aromatics Extractn	0	0	0	-7.831	-7.831
HPT	Pygas H2 Treater	0	0	0	-2.908	-2.908
CAPACITY ROWS . . .						
CRD	Crude Distillation	6060,000		6120,000		
VAC	Vacuum Unit	2537,000		2537,000		
CKD	Delayed Coker Drum	18,268		29,835		
CKV	COKER CHARGE	497,328		587,662		
SPT	UnsatGaso Splitter	476,680				
VBR	Visbreaker	0		20,700		
DAU	Solvent Deasphalt	0	0	0		-2.972
HKT	Resid Hydrotreater	240,800		240,800		
HOL	Resid Hydrocracker	88,000		88,000		
VHK	Vacuum R/R HOL/RHT	231,842				
FCC	Cat Cracker	1935,304		2144,000		
HOC	HOC @5 %FCC + RCC	0		332,000		
CAR	FCC coke capacity	12,843				
THM	Thermal Cracker	0		171,630		
HCK	Hydrocracker	292,538		292,538		
DSL	Lt Gas Oil H2 Trtr	265,971		1414,035		
HGO	Hy Gas Oil H2 Trtr	953,590		953,590		
H2F	Naphtha H2 Treater	1494,455		1685,160		
CUT	Pygas Bnz Heartcut	0				
IS4	C4 Isomerization	53,280		53,280		
ISM	C5+ Isomerization	160,650		160,650		

CAPACITY ROWS (CONTINUED)

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
RGL	HP Cat Ref - Mogas	1379,260		1615,860		
RAL	Low Pres Arom Ref	300,000		300,000		
BNZ	Benzene Tower	268,843				
TOL	Toluene Tower	183,397				
XYL	Xylene Tower	133,442				
EXT	Aromatics Extractn	68,474				
ALK	Alkylation	473,490		473,490		
AC5	Cat C5 splitter	11,333				
CPL	Cat Poly	36,090		36,090		
DAK	Toluene Dealkylatn	19,000		19,000		-18.100
BDH	C4 De Hydrogenatio	0		0		
MBE	MethylTert But Eth	0		32,400		
EBE	Ethyl Tert But Eth	0		0		
TAM	Tert Amyl Meth Eth	0		0		
H2M	Stm Ref (H2-MSCF)	636,124		770,940		
OXI	Partial Oxidation	0		56,250		
LWX	Lubes	111,268				
ASP	Asphalt	111,962				
SCE	Ethane Cracking	0		0		-31.541
SCP	Propane Cracking	0		0		-81.033
SCB	Butane Cracking	0		0		
SCK	Total Steam Crack	0	0	0		-98.056
SCN	Naphtha Cracking	0		0		-301.562
SCO	Gas Oil Cracking	0		0		
HPT	Pygas H2 Treater	0				
H2P	Cryogenic	0		85,500		
H2O	Cooling Water	4538,639				
KWH	Power Distribution	1535,284				
STM	Boiler House	35004183				
PWR	Power Generatn kVa	1535,284				
WAT	Water Treatment	231,852				
MRX	Merox Treaters	1840,032				
SUL	Sulfur Recovery	4,823				
RGH	LP Cat Ref - Mogas	0				
AST	Aromatics Saturatn	0				
LPC	Light HC Cracker	0				

MISCELLANEOUS . . .

... (NONE)

UNIT OPERATIONS STATISTICS . . .

@ABPFCCN	CAT CRACKER ABP	792.985
@ABPFCCD	-----------------	
@CNVFCCN	CAT CRACK CONVERSN	80.014
@CNVFCCD	-----------------	
@KFCFCCN	CAT CRACK K-FACTOR	11.801
@KFCFCCD	-----------------	
@HYFH2FT	XS H2 TO FUEL MSCF	0

```
                     ACTIVITY  MINIMUM  MAXIMUM OBJ COEF RED COST
                     --------  -------  ------- -------- --------

UNIT OPERATIONS STATISTICS (CONTINUED)

QRONRGLN AVG RON LO-P PLAT   100.000
QRONRGLD -----------------

ECONOMIC SUMMARY . . .                $/CD

        SALES                      91,444,920
        PURCHASES                  -4,105,634
        UTIL & CHEM                -4,470,004
                                   -----------
          NET OPERATING REVENUE    82,869,280

END OF SUMMARY REPORT . . .

ENDATA

ELEMENT MARKER
ENDATA
```

NIPER HEAVY OIL REFINING STUDY , CASE=FIVE90 1. 1. 1

NEW FACILITY INVESTMENT SUMMARY (CONTINUED)

PROCESS	------------ INVESTMENT $*1000 -------------				
	PLANT	OFFSITE	CATALYST	ROYALTY	TOTAL

PROCESS	------------ INVESTMENT $*1000 -------------				
	PLANT	OFFSITE	CATALYST	ROYALTY	TOTAL

Table C-2

NIPER HEAVY OIL REFINING STUDY , CASE=FIVE90 2. 1. 1

MATERIAL AND ECONOMIC BALANCE

PRODUCTS (WEIGHT BASIS)	$/TONS	TONS/CD	$/CD	MINIMUM	MAXIMUM	$/TONS
COK Coke	5.000	25,689	128,444			
TRANSFERS IN		-25,689				
		-------	---------			
TOTAL PRODUCTION (WEIGHT)		0	128,444			

HEATING VALUE EQUIVALENT BARRELS

* ESTIMATED FROM WEIGHT AND SPECIFIC GRAVITY

** POSITIVE INCR PROFIT IMPLIES INCENTIVE FOR INCREASED ACTIVITY

MATERIAL AND ECONOMIC BALANCE

PRODUCTS (VOLUME BASIS)	$/BBL	BBL/CD	$/CD	MINIMUM	MAXIMUM	$/BBL
MRG Regular Leaded		66,578		66,578	66,578	-30.290
MUR Unleaded Regular	29.530	2,090,081	61,720,084			
MUI Unleaded Midgrade		367,000		367,000	367,000	-30.340
MUP Unleaded Premium		489,000		489,000	489,000	-31.556
		-------	---------			
TOTAL GASOLINE		3,012,659	61,720,084			
AVG Aviation Gasoline		13,584		13,584	13,584	-32.875
JP4 JP4 Jet		96,532		96,532	96,532	-28.755
		-------	---------			
TOTAL AV NAPHTHA		110,115				
JTA Aviation Jet Fuel		649,225		649,225	649,225	-28.548
KER Kerosene		18,567		18,567	18,567	-27.418
N2D Diesel	27.430	868,995	23,836,524			
N2O Heating Oil		391,000		391,000	391,000	-27.418
		-------	---------			
TOTAL DISTILLATE		1,927,786	23,836,524			
LS6 LOW Sulf FO <0.3%		32,000		32,000	32,000	-26.068
MS6 MED Sulf FO <1.0%		75,000		75,000	75,000	-22.226
HS6 HI Sulfur FO 3.0%	14.460	255,000	3,687,300	255,000	255,000	-7.103
		-------	---------			
TOTAL FUEL OIL		362,000	3,687,300			
LVN Petrochem Naphtha		104,814		104,814	104,814	-22.291
PCO Petrochem Other		109,000		109,000	109,000	-27.485
NPH Spec Naphtha		33,197		33,197	33,197	-22.304
LWX Lubes + Waxes		111,268		111,269	111,269	-28.258
ASP Asphalt		111,962		111,962	111,962	-20.263
BNZ Benzene		44,000		44,000	44,000	-65.051
TOL Toluene		26,000		26,000	26,000	-38.938
XYL Xylene		58,000		58,000	58,000	-67.668
LPG Liq Pet Gas	10.000	207,257	2,072,568		291,000	
		-------	---------			
TOTAL MISC.		805,498	2,072,568			
PGF#Plant Fuel Gas		204,764				
PRF#Resid Plant Fuel		3,000		3,000	3,000	-5.003
		-------	---------			
PLANT FUEL & FLARE		207,764				
LOS VOLUME LOSS		-268,242				
TRANSFERS OUT		121,417				
		-------	---------			
TOTAL PRODUCTION (VOLUME)		6,278,998	91,316,472			

MATERIAL AND ECONOMIC BALANCE (CONTINUED)

FEEDS (VOLUME BASIS)	$/BBL	BBL/CD	$/CD	MINIMUM	MAXIMUM	$/BBL
JAY EAST LIGHT		15,000		15,000	15,000	25.701
CSM CUSHING SWEET		297,000		297,000	297,000	25.442
RWT WEST TEXAS INT		652,000		652,000	652,000	25.692
GIB LOUISIANA SWEET		1,393,000		1,393,000	1,393,000	26.137
BLV GULF COAST HVY		49,000		49,000	49,000	24.319
ANS Alaska North Slope		339,000		339,000	339,000	24.434
		-------	---------			
DOMESTIC CRUDE		2,745,000				
LOY CANADIAN BLEND		7,000		7,000	7,000	23.747
BCF SO. AMERICAN MED		1,042,000		1,042,000	1,042,000	23.613
B17 SO. AMERICAN HVY		110,000		110,000	110,000	22.744
ARL MIDDLE EAST		1,358,000		1,358,000	1,358,000	24.936
BON AFRICAN		660,000		660,000	660,000	25.985
BSX EUROPE		138,000		138,000	138,000	25.547
		-------	---------			
IMPORTS		3,315,000				
IC4 Iso Butane	-20.000	81,661	-1,633,223		200,000	
NC4 Normal Butane	-18.000	137,356	-2,472,411		200,000	
		-------	---------			
OTHER FEEDSTOCK		219,017	-4,105,634			
		-------	---------			
TOTAL FEEDSTOCKS (VOLUME)		6,279,018	-4,105,634			
			=========			
PRODUCTION MARGIN			87,210,838			

HEATING VALUE EQUIVALENT BARRELS

* ESTIMATED FROM VOLUME AND SPECIFIC GRAVITY

** POSITIVE INCR PROFIT IMPLIES INCENTIVE FOR INCREASED ACTIVITY

NIPER HEAVY OIL REFINING STUDY , CASE=FIVE90 4. 1. 1

UTILITIES PURCHASES AND SALES

			PURCHASES	COST	TOTAL	SALES	PRICE	TOTAL	INCR VAL
C82	CAT/CHEM	DOLLARS	1351,996	-1.210	-1635915				-1.210
FUL	PLT FUEL	MM-BTU	1710,921	-1.850	-3165204				-1.850
H2O	COOL H2O	M-GAL							-0.113
KWH	ELECTRIC	KWH		-0.050					-0.030
PWR	PWR GEN	KWH							-0.030
STM	STEAM	M-LB							-2.490
TEL	TEL	G-GL/BBL	6,658	-0.980	-6,525				-0.980
SUL	SULFUR	TONS				4,823	70.000	337,638	-70.000
WAT	PROC H2O	M-GAL							-0.076
OXN	OXYGEN	TONS		-100.000					-100.000
PPP	POOL ERR	TOTAL		-10.000					-10.000
	FINAL TOTAL				-4807644			337,638	

OVERALL ECONOMIC SUMMARY

		$/CD	M$/YR
FROM WEIGHT BASIS SUMMARY			
SALES	128,444		
PURCHASES			

NET	128,444		
FROM VOLUME BASIS SUMMARY			
SALES	91,316,472		
PURCHASES	-4,105,634		

NET	87,210,840		
GROSS OPERATING REVENUE		87339288	31878841
UTIL & MISC OPER COSTS		-4470005	-1631552
		--------	--------
NET OPERATING REVENUE		82869280	30247288

RPMS 2000 RUNS
REGION 5
THE YEAR 1995
SUBSTANTIATING TABLES

NIPER HEAVY OIL REFINING STUDY CASE = FIVE95 , ITER = -3884, OBJ VALUE = 35834.81 300. 1.

ELEMENT PEEK

SUMMARY REPORT . . .

CASE = FIVE95 (.) VOL BALANCE CLOSURE = -19.715
ITERATION NUMBER = -3884 WGT BALANCE CLOSURE = 0.
OBJECTIVE VALUE = 35834.815 (35834.815) MAXINV = 863.053

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
VOLUME BASIS PURCHASES . . .						
JAY	EAST LIGHT	10,000	10,000	10,000	0.	23.963
CSM	CUSHING SWEET	254,000	254,000	254,000	0.	23.962
WSO	MID WEST SOUR	0	0	0	0.	23.191
ATR	MID WEST HVY	0	0	0	0.	22.278
BOO	ROCKY MTN HVY	0	0	0	0.	22.694
RWT	WEST TEXAS INT	611,000	611,000	611,000	0.	24.218
GIB	LOUISIANA SWEET	1305,000	1305,000	1305,000	0.	24.586
BLV	GULF COAST HVY	57,000	57,000	57,000	0.	23.565
ANS	Alaska North Slope	285,000	285,000	285,000	0.	23.374
SSB	CALIFORNIA MED	0	0	0	0.	24.249
KES	CALIFORNIA HVY	0	0	0	0.	22.840

	DOMESTIC CRUDE	2522,000				
LOY	CANADIAN BLEND	7,000	7,000	7,000	0.	22.802
BCF	SO. AMERICAN MED	1116,000	1116,000	1116,000	0.	22.772
B17	SO. AMERICAN HVY	122,000	122,000	122,000	0.	22.124
ARL	MIDDLE EAST	1561,000	1561,000	1561,000	0.	23.677
BON	AFRICAN	602,000	602,000	602,000	0.	24.454
BSX	EUROPE	126,000	126,000	126,000	0.	24.157
CHA	ASIA	0	0	0	0.	24.838

	IMPORTS	3534,000				
C2S	Ethane	0	0	0	-8.190	-3.245
C3S	Propane	0	0	98,000	-14.000	-4.000
IC4	Iso Butane	200,000	0	200,000	-20.000	5.071
NC4	Normal Butane	142,496	0	200,000	-18.000	
TOL	Purchased octane	0	0	100,000	-50.000	-15.546
MTB	MTBE	0	0	63,000	-49.000	-14.805
ETL	Ethanol	0	0	0	-25.620	9.564
MTL	Methanol	75,582	0		-23.800	

	OTHER FEEDSTOCK	418,078				
		========				
	TOTAL	6474,078				
WEIGHT BASIS SALES . . .						
COK	Coke	31,454	0		5.000	
C2U	Ethylene	0	0	0	0.	

Table C-3

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
WEIGHT BASIS SALES (CONTINUED)						
PPY	Propylene Mix	0	0	0	0.	
BDU	Butadiene	0	0	0	0.	-1104.66
SC4	Stm Crackr Butenes	0	0	0	0.	-481.946
LSA	WT LOSS & ADJ	0			0.	
	TOTAL	31,454				
VOLUME BASIS SALES . . .						
MRG	Regular Leaded	0	0	0	0.	-19.723
MUR	Unleaded Regular	1227,808	0	1246,000	26.990	
MUI	Unleaded Midgrade	415,000	415,000	415,000	0.	-27.636
MUP	Unleaded Premium	415,000	415,000	415,000	0.	-28.605
MOR	O3 non-att Regular	0	0	0	0.	-19.834
MOP	O3 non-att Premium	0	0	0	0.	-19.834
MCR	CO non-att Regular	0	0	0	0.	-21.086
MCP	CO non-att Premium	0	0	0	0.	-19.834
MBR	Oxy Fuel+ Reform R	671,000	671,000	671,000	0.	-27.311
MBP	Oxy Fuel+ Reform P	447,000	447,000	447,000	0.	-28.398
GUR	Regular + Ethanol	0	0	0	0.	-27.809
GOR	O3 na Regular+ethl	0	0	0	0.	-21.369
GCR	CO na Regular+ethl	0	0	0	0.	-22.496
	TOTAL GASOLINE	3175,808				
AVG	Aviation Gasoline	13,584	13,584	13,584	0.	-29.646
JP4	JP4 Jet	96,532	96,532	96,532	0.	-26.438
	TOTAL AV NAPHTHA	110,115				
JTA	Aviation Jet Fuel	805,000	805,000	805,000	0.	-26.860
KER	Kerosene	18,567	18,567	18,567	0.	-24.698
N2D	Diesel	413,270	0	636,000	24.780	
N2O	Heating Oil	717,000	717,000	717,000	0.	-24.659
	TOTAL DISTILLATE	1953,837				
LS6	LOW Sulf FO <0.3%	32,000	32,000	32,000	0.	-23.865
MS6	MED Sulf FO <1.0%	75,000	75,000	75,000	0.	-21.083
HS6	HI Sulfur FO 3.0%	244,000	244,000	244,000	13.860	-5.942
BKR	Bunker Fuel 4.0%	0	0	0	0.	-16.639
	TOTAL FUEL OIL	351,000				
LVN	Petrochem Naphtha	104,814	104,814	104,814	0.	-21.993
PCO	Petrochem Other	109,000	109,000	109,000	0.	-24.68:
NPH	Spec Naphtha	33,197	33,197	33,197	0.	-22.023
LWX	Lubes • Waxes	111,268	111,268	111,268	0.	-26.795
ASP	Asphalt	111,962	111,962	111,962	0.	-18.779
BNZ	Benzene	44,000	44,000	44,000	0.	-54.256

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
VOLUME BASIS SALES (CONTINUED)						
TOL	Purchased octane	26,000	26,000	26,000	0.	-34.454
XYL	Xylene	58,000	58,000	58,000	0.	-57.030
HAR	HEAVY AROMATICS	0	0	0	0.	-29.753
LPG	Liq Pet Gas	199,421	0	291,000	10.000	
	TOTAL MISC.	797,662				
PGF	Plant Fuel Gas	193,470	0		0.	
PRF	Resid Plant Fuel	3,000	3,000	3,000	0.	-9.870
	PLANT FUEL & FLARE	196,470				
LOS	VOLUME LOSS	-259,498			0.	
	TOTAL	6325,392				
UTILITY PURCHASES . . .						
CB2	CAT/CHEM DOLLARS	1310,794	0		-1.210	
TEL	TEL G-GL/BBL	0	0		-0.980	-0.980
FUL	PLT FUEL MM-BTU	1621,476	0		-1.850	
KWH	ELECTRIC KWH	0	0	0	-0.050	-0.017
OXN	OXYGEN TONS	0	0		-100.000	-100.000
PPP	POOL ERR TOTAL	0	0		-10.000	-8.627
H2O	COOL H2O M-GAL	0	0	0	0.	0.155
STM	STEAM M-LB	0	0	0	0.	2.492
WAT	PROC H2O M-GAL	0	0	0	0.	0.271
PWR	PWR GEN KWH	0	0	0	0.	0.033
UTILITY SALES . . .						
SUL	SULFUR TONS	4,459	0		70.000	
NEW FACILITIES . . .						
CRD	Crude Distillation	143,000	0		-0.252	
VAC	Vacuum Unit	385,982	0		-0.287	
CKD	Delayed Coker Drum	0	0		-119.515	-119.515
CKV	COKER CHARGE	0	0		-3.115	-3.115
VBR	Visbreaker	0	0		-2.838	-2.824
HOL	Resid Hydrocracker	0	0		-15.543	-10.550
HOC	HOC @5 %FCC + RCC	0	0		-7.876	-7.876
FCC	Cat Cracker	0	0		-6.325	-6.325
HGO	Hy Gas Oil H2 Trtr	0	0		-4.724	-4.412
DSL	Lt Gas Oil H2 Trtr	0	0		-3.352	-3.040
HCK	Hydrocracker	0	0		-11.020	-4.972
VHK	Vacuum R/R HOL/RHT	0	0		-1.416	-1.416
HKT	Resid Hydrotreater	0	0		-10.165	-10.165
H2F	Naphtha H2 Treater	0	0		-2.772	-2.772
RGL	HP Cat Ref - Mogas	0	0		-5.427	-5.427

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
NEW FACILITIES (CONTINUED)						
ALK	Alkylation	0	0		-10.890	-10.264
CPL	Cat Poly	0	0		-5.844	-5.844
ISM	C5+ Isomerization	0	0		-6.710	-6.635
IS4	C4 Isomerization	0	0		-7.518	-1.984
BDH	C4 De Hydrogenatio	108,456	0		-0.749	
M3E	MethylTert But Eth	191,149	0		-0.823	
E3E	Ethyl Tert But Eth	0	0		-35.436	
TAM	Tert Amyl Meth Eth	0	0		-35.436	-35.436
H2M	Stm Ref (H2-MSCF)	0	0		-1.526	-1.526
H2P	Cryogenic	0	0		-0.741	-0.741
OXI	Partial Oxidation	0	0		-2.408	
SUL	Sulfur Recovery	0	0		-696.059	-696.059
ACS	Cat C5 splitter	0	0		-0.847	-0.847
SPT	UnsatGaso Splitter	0	0		-0.485	-0.454
PWR	Power Generatn kVa	0	0		-1.125	-1.125
H20	Cooling Water	940,219	0		-0.045	
MRX	Merox Treaters	0	0		-0.876	-0.858
STM	Boiler House	0	0		-0.100	-0.100
KWH	Power Distribution	0	0		-0.651	-0.651
WAT	Water Treatment	46,447	0		-0.279	
RAL	Low Pres Arom Ref	0	0	0	-5.395	3.151
BN2	Benzene Tower	0	0	0	-1.455	-1.455
TOL	Toluene Tower	0	0	0	-1.533	-1.533
XYL	Xylene Tower	0	0	0	-1.480	-1.480
EXT	Aromatics Extractn	0	0	0	-7.831	-7.831
HPT	Pygas H2 Treater	0	0		-2.908	-2.908
CAPACITY ROWS . . .						
CRD	Crude Distillation	5913,000		5913,000		
VAC	Vacuum Unit	2437,000		2437,000		
CXD	Delayed Coker Drum	22,568		32,000		
CXV	COKER CHARGE	595,207		621,000		
SPT	UnsatGaso Splitter	477,000		477,000		
VBR	Visbreaker	0		0		
DAU	Solvent Deasphalt	0	0	0		-2.901
HKT	Resid Hydrotreater	0		241,000		
HOL	Resid Hydrocracker	88,000		88,000		
VHK	Vacuum R/R HOL/RHT	36,719		232,000		
FCC	Cat Cracker	1898,000		1898,000		
HOC	HOC a5 %FCC + RCC	146,183		408,000		
CAR	FCC coke capacity	13,174				
THM	Thermal Cracker	0		0		
HCX	Hydrocracker	344,000		344,000		
DSL	Lt Gas Oil H2 Trtr	214,000		214,000		
HGO	Hy Gas Oil H2 Trtr	1042,000		1042,000		
H2F	Naphtha H2 Treater	1342,639		1507,000		
CUT	Pygas Bnz Heartcut	0				
IS4	C4 Isomerization	65,000		65,000		
ISM	C5+ Isomerization	183,000		183,000		

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
		--------	-------	-------	--------	--------
CAPACITY ROWS (CONTINUED)						
RGL	HP Cat Ref - Mogas	1192,470		1377,000		
RAL	Low Pres Arom Ref	300,000		300,000		
BNZ	Benzene Tower	269,670				
TOL	Toluene Tower	186,815				
XYL	Xylene Tower	134,631				
EXT	Aromatics Extractn	67,310				
ALK	Alkylation	468,000		468,000		
AC5	Cat C5 splitter	10,688		11,000		
CPL	Cat Poly	3,847		36,000		
DAK	Toluene Dealkylatn	19,000		19,000		-12.731
BDH	C4 De Hydrogenatio	0		0		
MBE	MethylTert But Eth	30,000		30,000		
EBE	Ethyl Tert But Eth	0		0		
TAM	Tert Amyl Meth Eth	0		4,000		
H2M	Stm Ref (H2-MSCF)	527,533		641,000		
OXI	Partial Oxidation	0		0		
LWX	Lubes	111,268				
ASP	Asphalt	111,962				
SCE	Ethane Cracking	0		0		-95.268
SCP	Propane Cracking	0		0		-118.431
SCB	Butane Cracking	0		0		
SCK	Total Steam Crack	0	0	0		201.408
SCN	Naphtha Cracking	0		0		-245.359
SCO	Gas Oil Cracking	0		0		-277.188
HPT	Pygas H2 Treater	0				
H2P	Cryogenic	0		16,000		
H2O	Cooling Water	4539,000		4539,000		
KWH	Power Distribution	1448,138		1535,000		
STM	Boiler House	31821324		3500E+07		
PWR	Power Generatn kVa	1448,138		1535,000		
WAT	Water Treatment	232,000		232,000		
MRX	Merox Treaters	1840,000		1840,000		
SUL	Sulfur Recovery	4,459		5,000		
RGH	LP Cat Ref - Mogas	0				
AST	Aromatics Saturatn	0				
LPC	Light HC Cracker	0				

MISCELLANEOUS . . .

... (NONE)

UNIT OPERATIONS STATISTICS . . .

QABPFCCN	CAT CRACKER ABP	787.747
QABPFCCD	-----------------	
QCNVFCCN	CAT CRACK CONVERSN	80.163
QCNVFCCD	-----------------	
QKFCFCCN	CAT CRACK K-FACTOR	11.816
QKFCFCCD	-----------------	
QHYFH2FT	XS H2 TO FUEL MSCF	0

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                      ACTIVITY  MINIMUM  MAXIMUM OBJ COEF RED COST
                      --------  -------  ------- -------- --------

UNIT OPERATIONS STATISTICS (CONTINUED)

QRONRGLN AVG RON LO-P PLAT    96.460
QRONRGLD -----------------

ECONOMIC SUMMARY . . .                 $/CD

        SALES                     48,912,656
        PURCHASES                 -8,363,777
        UTIL & CHEM               -4,273,640
                                 -----------
          NET OPERATING REVENUE   36,275,240

END OF SUMMARY REPORT . . .

ENDATA

ELEMENT MARKER
ENDATA
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NIPER HEAVY OIL REFINING STUDY , CASE=FIVE95 1. 1. 1

NEW FACILITY INVESTMENT SUMMARY

	PROCESS	SIZE/SD	$/U/CD	TOT INV	EXPENSES	CAP REC
				$*1000	$/CD	$/CD
CRD	Crude Distillation	158,889	-0.252	70,883	12,723	43,798
VAC	Vacuum Unit	419,546	-0.287	170,967	28,532	105,637
BDH	C4 De Hydrogenatio	115,379	-0.749	174,514	29,314	107,829
MBE	MethylTert But Eth	205,537	-0.823	336,460	56,038	207,892
H2O	Cooling Water	989,705	-0.045	69,994	11,638	43,248
WAT	Water Treatment	47,883	-0.279	25,294	4,520	15,629
				--------	--------	--------
	SUB-TOTAL UNITS			848,113	142,766	524,033

	PROCESS	INVESTMENT $*1000				
		PLANT	OFFSITE	CATALYST	ROYALTY	TOTAL
CRD	Crude Distillation	52,506	18,377			70,883
VAC	Vacuum Unit	125,711	45,256			170,967
BDH	C4 De Hydrogenatio	140,090	29,809	4,615		174,514
MBE	MethylTert But Eth	265,879	67,292	3,289		336,460
H2O	Cooling Water	61,399	8,596			69,994
WAT	Water Treatment	22,995	2,299			25,294
		--------	--------	--------	--------	--------
	INVESTMENT TOTALS	668,580	171,630	7,904		848,113

Table C-4

MATERIAL AND ECONOMIC BALANCE

PRODUCTS (WEIGHT BASIS)	$/TONS	TONS/CD	$/CD	MINIMUM	MAXIMUM	$/TONS
COK Coke	5.000	31,454	157,270			
TRANSFERS IN		-31,454				
		-------	---------			
TOTAL PRODUCTION (WEIGHT)			157,270			

HEATING VALUE EQUIVALENT BARRELS

* ESTIMATED FROM WEIGHT AND SPECIFIC GRAVITY

** POSITIVE INCR PROFIT IMPLIES INCENTIVE FOR INCREASED ACTIVITY

NIPER HEAVY OIL REFINING STUDY , CASE=FIVE95 3. 1. 1

MATERIAL AND ECONOMIC BALANCE

PRODUCTS (VOLUME BASIS)	$/BBL	BBL/CD	$/CD	MINIMUM	MAXIMUM	$/BBL
MUR Unleaded Regular	26.990	1,227,808	33,138,524		1,246,000	
MUI Unleaded Midgrade		415,000		415,000	415,000	-27.636
MUP Unleaded Premium		415,000		415,000	415,000	-28.605
MBR Oxy Fuel+ Reform R		671,000		671,000	671,000	-27.311
MBP Oxy Fuel+ Reform P		447,000		447,000	447,000	-28.398
		-------	---------			
TOTAL GASOLINE		3,175,808	33,138,524			
AVG Aviation Gasoline		13,584		13,584	13,584	-29.646
JP4 JP4 Jet		96,532		96,532	96,532	-26.438
		-------	---------			
TOTAL AV NAPHTHA		110,115				
JTA Aviation Jet Fuel		805,000		805,000	805,000	-26.860
KER Kerosene		18,567		18,567	18,567	-24.698
N2D Diesel	24.780	413,270	10,240,818		636,000	
N2O Heating Oil		717,000		717,000	717,000	-24.659
		-------	---------			
TOTAL DISTILLATE		1,953,837	10,240,818			
LS6 LOW Sulf FO <0.3%		32,000		32,000	32,000	-23.865
MS6 MED Sulf FO <1.0%		75,000		75,000	75,000	-21.083
HS6 HI Sulfur FO 3.0%	13.860	244,000	3,381,840	244,000	244,000	-5.942
		-------	---------			
TOTAL FUEL OIL		351,000	3,381,840			
LVN Petrochem Naphtha		104,814		104,814	104,814	-21.993
PCO Petrochem Other		109,000		109,000	109,000	-24.681
NPH Spec Naphtha		33,197		33,197	33,197	-22.023
LWX Lubes + Waxes		111,268		111,269	111,269	-26.795
ASP Asphalt		111,962		111,962	111,962	-18.779
BNZ Benzene		44,000		44,000	44,000	-54.256
TOL Toluene		26,000		26,000	26,000	-34.454
XYL Xylene		58,000		58,000	58,000	-57.030
LPG Liq Pet Gas	10.000	199,421	1,994,206		291,000	
		-------	---------			
TOTAL MISC.		797,662	1,994,206			
PGF#Plant Fuel Gas		193,470				
PRF#Resid Plant Fuel		3,000		3,000	3,000	-9.870
		-------	---------			
PLANT FUEL & FLARE		196,470				
LOS VOLUME LOSS		-259,498				
TRANSFERS OUT		148,665				
		-------	---------			
TOTAL PRODUCTION (VOLUME)		6,474,058	48,755,388			

MATERIAL AND ECONOMIC BALANCE (CONTINUED)

FEEDS (VOLUME BASIS)	$/BBL	BBL/CD	$/CD	MINIMUM	MAXIMUM	$/BBL
JAY EAST LIGHT		10,000		10,000	10,000	23.963
CSN CUSHING SWEET		254,000		254,000	254,000	23.962
RWT WEST TEXAS INT		611,000		611,000	611,000	24.218
GIB LOUISIANA SWEET		1,305,000		1,305,000	1,305,000	24.586
BLV GULF COAST HVY		57,000		57,000	57,000	23.565
ANS Alaska North Slope		285,000		285,000	285,000	23.374
		-------	---------			
DOMESTIC CRUDE		2,522,000				
LOY CANADIAN BLEND		7,000		7,000	7,000	22.802
BCF SO. AMERICAN MED		1,116,000		1,116,000	1,116,000	22.772
B17 SO. AMERICAN HVY		122,000		122,000	122,000	22.124
ARL MIDDLE EAST		1,561,000		1,561,000	1,561,000	23.677
BON AFRICAN		602,000		602,000	602,000	24.454
BSX EUROPE		126,000		126,000	126,000	24.157
		-------	---------			
IMPORTS		3,534,000				
IC4 Iso Butane	-20.000	200,000	-4,000,000		200,000	5.071
NC4 Normal Butane	-18.000	142,496	-2,564,936		200,000	
MTL Methanol	-23.800	75,582	-1,798,841			
		-------	---------			
OTHER FEEDSTOCK		418,078	-8,363,777			
		-------	---------			
TOTAL FEEDSTOCKS (VOLUME)		6,474,078	-8,363,777			
			=========			
PRODUCTION MARGIN			40,391,611			

HEATING VALUE EQUIVALENT BARRELS

* ESTIMATED FROM VOLUME AND SPECIFIC GRAVITY

** POSITIVE INCR PROFIT IMPLIES INCENTIVE FOR INCREASED ACTIVITY

UTILITIES PURCHASES AND SALES

		PURCHASES	COST	TOTAL	SALES	PRICE	TOTAL	INCR VAL
C82 CAT/CHEM	DOLLARS	1310,794	-1.210	-1586061				-1.210
FUL PLT FUEL	MM-BTU	1621,476	-1.850	-2999730				-1.850
H2O COOL H2O	M-GAL							-0.155
KWH ELECTRIC	KWH		-0.050					-0.033
PWR PWR GEN	KWH							-0.033
STM STEAM	M-LB							-2.492
TEL TEL	G-GL/BBL		-0.980					0.
SUL SULFUR	TONS				4,459	70.000	312,151	-70.000
WAT PROC H2O	M-GAL							-0.271
OXN OXYGEN	TONS		-100.000					0.
PPP POOL ERR	TOTAL		-10.000					-1.373
				======			======	
FINAL TOTAL				-4585792			312,151	

OVERALL ECONOMIC SUMMARY

		$/CD	M$/YR
FROM WEIGHT BASIS SUMMARY			
SALES	157,270		
PURCHASES			

NET	157,270		
FROM VOLUME BASIS SUMMARY			
SALES	48,755,388		
PURCHASES	-8,363,777		

NET	40,391,612		
GROSS OPERATING REVENUE		40548880	14800342
UTIL & MISC OPER COSTS		-4273640	-1559879
		--------	--------
NET OPERATING REVENUE		36275240	13240463
NEW EQUIPMENT EXPENSES			
MAINTENANCE	-92,944		
INS,TAX,OHD	-46,472		
FIXED OPER COST	-3,350		

TOTAL UNITS		-142,766	-52,110
		========	========
NET OPER PROFIT		36132476	13188354
CAPITAL RECOVERY			
UNITS		-524,033	-191,272
		--------	--------
TOTAL		-524,033	-191,272
		========	========
NET REVENUE		35608440	12997081

RPMS 2000 RUNS
REGION 5
THE YEAR 2000
SUBSTANTIATING TABLES

ELEMENT PEEK

SUMMARY REPORT . . .

CASE = FIVE00 (.) VOL BALANCE CLOSURE = -19.580
ITERATION NUMBER = 4102 WGT BALANCE CLOSURE = 0.000
OBJECTIVE VALUE = 40048.799 (40048.799) MAXINV = 888.951

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
VOLUME BASIS PURCHASES . . .						
JAY	EAST LIGHT	5,000	5,000	5,000	0.	23.282
CSM	CUSHING SWEET	219,000	219,000	219,000	0.	23.037
WSO	MID WEST SOUR	0	0	0	0.	22.060
ATR	MID WEST HVY	0	0	0	0.	20.791
BOD	ROCKY MTN HVY	0	0	0	0.	21.435
RWT	WEST TEXAS INT	552,000	552,000	552,000	0.	23.428
GIB	LOUISIANA SWEET	1180,000	1180,000	1180,000	0.	23.995
BLV	GULF COAST HVY	83,000	83,000	83,000	0.	22.344
ANS	Alaska North Slope	205,000	205,000	205,000	0.	22.258
SSB	CALIFORNIA MED	0	0	0	0.	23.310
KES	CALIFORNIA HVY	0	0	0	0.	21.309

	DOMESTIC CRUDE	2244,000				
LOY	CANADIAN BLEND	7,000	7,000	7,000	0.	21.557
BCF	SO. AMERICAN MED	1144,000	1144,000	1144,000	0.	21.451
B17	SO. AMERICAN HVY	139,000	139,000	139,000	0.	20.601
ARL	MIDDLE EAST	2052,000	2052,000	2052,000	0.	22.708
BON	AFRICAN	493,000	493,000	493,000	0.	23.902
BSX	EUROPE	121,000	121,000	121,000	0.	23.379
CHA	ASIA	0	0	0	0.	24.396

	IMPORTS	3956,000				
C2S	Ethane	0	0	0	-8.190	-3.245
C3S	Propane	0	0	98,000	-14.000	-4.000
IC4	Iso Butane	200,000	0	200,000	-20.000	3.619
NC4	Normal Butane	131,309	0	500,000	-18.000	
TOL	Purchased octane	0	0	100,000	-50.000	-17.126
MTB	MTBE	0	0	63,000	-49.000	-16.317
ETL	Ethanol	0	0	0	-25.620	7.993
MTL	Methanol	77,097	0		-23.800	

	OTHER FEEDSTOCK	408,406				
		========				
	TOTAL	6608,406				
WEIGHT BASIS SALES . . .						
COK	Coke	34,214	0		5.000	
C2U	Ethylene	0	0	0	0.	

Table C-5

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
WEIGHT BASIS SALES (CONTINUED)						
PPY	Propylene Mix	0	0	0	0.	
BDU	Butadiene	0	0	0	0.	-1086.38
SC4	Stm Crackr Butenes	0	0	0	0.	-433.919
LSA	WT LOSS & ADJ	0			0.	
	TOTAL	34,214				
VOLUME BASIS SALES . . .						
MRG	Regular Leaded	0	0	0	0.	-20.921
MUR	Unleaded Regular	1260,000	0	1260,000	27.720	1.749
MUI	Unleaded Midgrade	420,000	420,000	420,000	0.	-26.575
MUP	Unleaded Premium	420,000	420,000	420,000	0.	-27.481
MOR	O3 non-att Regular	0	0	0	0.	-20.921
MOP	O3 non-att Premium	0	0	0	0.	-20.921
MCR	CO non-att Regular	0	0	0	0.	-21.996
MCP	CO non-att Premium	0	0	0	0.	-20.921
MBR	Oxy Fuel+ Reform R	679,000	679,000	679,000	0.	-26.422
MBP	Oxy Fuel+ Reform P	452,000	452,000	452,000	0.	-27.447
GUR	Regular + Ethanol	0	0	0	0.	-26.735
GOR	O3 na Regular+ethl	0	0	0	0.	-22.190
GCR	CO na Regular+ethl	0	0	0	0.	-23.158
	TOTAL GASOLINE	3231,000				
AVG	Aviation Gasoline	13,584	13,584	13,584	0.	-28.414
JP4	JP4 Jet	0	0	0	0.	-24.348
	TOTAL AV NAPHTHA	13,584				
JTA	Aviation Jet Fuel	861,000	861,000	861,000	0.	-26.646
KER	Kerosene	18,567	18,567	18,567	0.	-24.983
N2D	Diesel	492,535	0	645,000	25.660	
N2O	Heating Oil	727,000	727,000	727,000	0.	-24.778
	TOTAL DISTILLATE	2099,102				
LS6	LOW Sulf FO <0.3%	32,000	32,000	32,000	0.	-23.337
MS6	MED Sulf FO <1.0%	75,000	75,000	75,000	0.	-19.926
HS6	HI Sulfur FO 3.0%	244,000	244,000	244,000	14.160	-3.305
BKR	Bunker Fuel 4.0%	0	0	0	0.	-4.815
	TOTAL FUEL OIL	351,000				
LVN	Petrochem Naphtha	104,814	104,814	104,814	0.	-20.945
PCO	Petrochem Other	109,000	109,000	109,000	0.	-24.891
NPH	Spec Naphtha	33,197	33,197	33,197	0.	-20.957
LWX	Lubes + Waxes	111,268	111,268	111,268	0.	-25.697
ASP	Asphalt	111,962	111,962	111,962	0.	-15.969
BNZ	Benzene	44,000	44,000	44,000	0.	-56.569

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
VOLUME BASIS SALES (CONTINUED)						
TOL	Purchased octane	26,000	26,000	26,000	0.	-32.874
XYL	Xylene	58,000	58,000	58,000	0.	-60.517
HAR	HEAVY AROMATICS	0	0	0	0.	-28.481
LPG	Liq Pet Gas	201,311	0	291,000	10.000	
	TOTAL MISC.	799,552				
PGF	Plant Fuel Gas	201,987	0		0.	
PRF	Resid Plant Fuel	3,000	3,000	3,000	0.	-8.371
	PLANT FUEL & FLARE	204,987				
LOS	VOLUME LOSS	-252,552			0.	
	TOTAL	6446,673				
UTILITY PURCHASES . . .						
C82	CAT/CHEM DOLLARS	1399,904	0		-1.210	
TEL	TEL G-GL/BBL	0	0		-0.980	-0.980
FUL	PLT FUEL MM-BTU	1709,700	0		-1.850	
KWH	ELECTRIC KWH	0	0	0	-0.050	-0.017
OXN	OXYGEN TONS	0	0		-100.000	-100.000
PPP	POOL ERR TOTAL	0	0		-10.000	-6.945
H2O	COOL H2O M-GAL	0	0	0	0.	0.154
STM	STEAM M-LB	0	0	0	0.	2.492
WAT	PROC H2O M-GAL	0	0	0	0.	0.266
PWR	PWR GEN KWH	0	0	0	0.	0.033
UTILITY SALES . . .						
SUL	SULFUR TONS	5,000	0		70.000	
NEW FACILITIES . . .						
CRD	Crude Distillation	287,000	0		-0.198	
VAC	Vacuum Unit	349,581	0		-0.265	
CKD	Delayed Coker Drum	0	0		-119.515	-119.515
CKV	COKER CHARGE	0	0		-3.115	-2.194
VBR	Visbreaker	0	0		-2.838	
HOL	Resid Hydrocracker	0	0		-15.543	-10.429
HOC	HOC a5 %FCC + RCC	0	0		-7.876	-7.876
FCC	Cat Cracker	0	0		-6.325	-6.325
HGO	Hy Gas Oil H2 Trtr	0	0		-4.724	-3.652
DSL	Lt Gas Oil H2 Trtr	0	0		-3.352	-2.280
HCK	Hydrocracker	0	0		-11.020	-5.674
VHK	Vacuum R/R HOL/RHT	0	0		-1.416	-1.416
HKT	Resid Hydrotreater	0	0		-10.165	-10.165
H2F	Naphtha H2 Treater	0	0		-2.772	-2.772
RGL	HP Cat Ref - Mogas	0	0		-5.427	-5.427

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
NEW FACILITIES (CONTINUED)						
ALK	Alkylation	0	0		-10.890	-10.890
CPL	Cat Poly	0	0		-5.844	-5.844
ISM	C5+ Isomerization	0	0		-6.710	-6.395
IS4	C4 Isomerization	0	0		-7.518	-3.389
BDH	C4 De Hydrogenatio	114,071	0		-0.744	
MBE	MethylTert But Eth	195,582	0		-0.820	
EBE	Ethyl Tert But Eth	0	0		-35.436	
TAM	Tert Amyl Meth Eth	0	0		-35.436	-35.436
H2M	Stm Ref (H2-MSCF)	0	0		-1.526	-1.450
H2P	Cryogenic	0	0		-0.741	-0.741
OXI	Partial Oxidation	0	0		-2.408	
SUL	Sulfur Recovery	0	0		-696.059	-560.872
AC5	Cat C5 splitter	0	0		-0.847	-0.847
SPT	UnsatGaso Splitter	0	0		-0.485	-0.485
PWR	Power Generatn kVa	0	0		-1.125	-1.125
H2O	Cooling Water	983,051	0		-0.044	
MRX	Merox Treaters	0	0		-0.876	-0.876
STM	Boiler House	0	0		-0.100	-0.100
KWH	Power Distribution	0	0		-0.651	-0.651
WAT	Water Treatment	48,919	0		-0.272	
RAL	Low Pres Arom Ref	0	0	0	-5.395	4.232
BNZ	Benzene Tower	0	0	0	-1.455	-1.455
TOL	Toluene Tower	0	0	0	-1.533	-1.533
XYL	Xylene Tower	0	0	0	-1.480	-1.480
EXT	Aromatics Extractn	0	0	0	-7.831	-7.831
HPT	Pygas H2 Treater	0	0		-2.908	-2.908
CAPACITY ROWS . . .						
CRD	Crude Distillation	5913,000		5913,000		
VAC	Vacuum Unit	2437,000		2437,000		
CKD	Delayed Coker Drum	24,935		32,000		
CKV	COKER CHARGE	621,000		621,000		
SPT	UnsatGaso Splitter	457,804		477,000		
VBR	Visbreaker	0		0		
DAU	Solvent Deasphalt	0	0	0		-3.664
HKT	Resid Hydrotreater	146,886		241,000		
HOL	Resid Hydrocracker	88,000		88,000		
VHK	Vacuum R/R HOL/RHT	117,802		232,000		
FCC	Cat Cracker	1898,000		1898,000		
HOC	HOC ≥5 %FCC + RCC	53,625		408,000		
CAR	FCC coke capacity	13,245				
THM	Thermal Cracker	0		0		
HCK	Hydrocracker	344,000		344,000		
DSL	Lt Gas Oil H2 Trtr	214,000		214,000		
HGO	Hy Gas Oil H2 Trtr	1042,000		1042,000		
H2F	Naphtha H2 Treater	1467,301		1507,000		
CUT	Pygas Bnz Heartcut	0				
IS4	C4 Isomerization	65,000		65,000		
ISM	C5+ Isomerization	183,000		183,000		

		ACTIVITY	MINIMUM	MAXIMUM	OBJ COEF	RED COST
CAPACITY ROWS (CONTINUED)						
RGL	HP Cat Ref - Mogas	1327,223		1377,000		
RAL	Low Pres Arom Ref	300,000		300,000		
BNZ	Benzene Tower	266,181				
TOL	Toluene Tower	183,429				
XYL	Xylene Tower	130,400				
EXT	Aromatics Extractn	69,474				
ALK	Alkylation	453,604		468,000		
AC5	Cat C5 splitter	10,366		11,000		
CPL	Cat Poly	0		36,000		
DAK	Toluene Dealkylatn	19,000		19,000		-16.826
BDH	C4 De Hydrogenatio	0		0		
MBE	MethylTert But Eth	30,000		30,000		
EBE	Ethyl Tert But Eth	0		0		
TAM	Tert Amyl Meth Eth	0		4,000		
H2M	Stm Ref (H2-MSCF)	641,000		641,000		
OXI	Partial Oxidation	0		0		
LWX	Lubes	111,268				
ASP	Asphalt	111,962				
SCE	Ethane Cracking	0		0		-100.224
SCP	Propane Cracking	0		0		-123.348
SCB	Butane Cracking	0		0		
SCX	Total Steam Crack	0	0	0		206.141
SCN	Naphtha Cracking	0		0		-260.864
SCO	Gas Oil Cracking	0		0		-258.081
HPT	Pygas H2 Treater	0				
H2P	Cryogenic	0		16,000		
H2O	Cooling Water	4539,000		4539,000		
KWH	Power Distribution	1493,461		1535,000		
STM	Boiler House	33676531		3500E+07		
PWR	Power Generatn kVa	1493,461		1535,000		
WAT	Water Treatment	232,000		232,000		
MRX	Merox Treaters	1780,679		1840,000		
SUL	Sulfur Recovery	5,000		5,000		
RGN	LP Cat Ref - Mogas	0				
AST	Aromatics Saturatn	0				
LPC	Light HC Cracker	0				

MISCELLANEOUS . . .

... (NONE)

UNIT OPERATIONS STATISTICS . . .

QABPFCCN	CAT CRACKER ABP	797.127
QABPFCCD	------------------	
QCNVFCCN	CAT CRACK CONVERSN	79.867
QCNVFCCD	------------------	
QKFCFCCN	CAT CRACK K-FACTOR	11.790
QKFCFCCD	------------------	
QHYFH2FT	XS H2 TO FUEL MSCF	0

```
                     ACTIVITY MINIMUM MAXIMUM OBJ COEF RED COST
                     -------- ------- ------- -------- --------

UNIT OPERATIONS STATISTICS (CONTINUED)

ORONRGLN AVG RON LO-P PLAT   95.720
ORONRGLD ------------------

ECONOMIC SUMMARY . . .              $/CD

        SALES                   53,204,880
        PURCHASES               -8,198,465
        UTIL & CHEM             -4,506,829
                                -----------
          NET OPERATING REVENUE 40,499,588

END OF SUMMARY REPORT . . .

ENDATA

ELEMENT MARKER
ENDATA
```

NIPER HEAVY OIL REFINING STUDY , CASE=FIVE00 1. 1. 1

NEW FACILITY INVESTMENT SUMMARY

	PROCESS	SIZE/SD	$/U/CD	TOT INV	EXPENSES	CAP REC
				$*1000	$/CD	$/CD
CRD	Crude Distillation	318,889	-0.198	111,481	19,397	68,882
VAC	Vacuum Unit	379,979	-0.265	158,726	26,520	98,074
BDH	C4 De Hydrogenatio	121,352	-0.744	179,906	30,201	111,161
MBE	MethylTert But Eth	210,304	-0.820	341,126	56,805	210,775
H2O	Cooling Water	1034,791	-0.044	72,405	12,034	44,738
WAT	Water Treatment	50,432	-0.272	26,162	4,663	16,165
				--------	--------	--------
	SUB-TOTAL UNITS			889,805	149,619	549,793

	PROCESS	PLANT	OFFSITE	CATALYST	ROYALTY	TOTAL
		------------ INVESTMENT $*1000				------------
CRD	Crude Distillation	82,578	28,902			111,481
VAC	Vacuum Unit	116,710	42,016			158,726
BDH	C4 De Hydrogenatio	144,322	30,730	4,854		179,906
MBE	MethylTert But Eth	269,536	68,225	3,365		341,126
H2O	Cooling Water	63,513	8,892			72,405
WAT	Water Treatment	23,783	2,378			26,162
		--------	--------	--------	--------	--------
	INVESTMENT TOTALS	700,442	181,144	8,219		889,805

Table C-6

NIPER HEAVY OIL REFINING STUDY , CASE=FIVE00 2. 1. 1

MATERIAL AND ECONOMIC BALANCE

PRODUCTS (WEIGHT BASIS)	$/TONS	TONS/CD	$/CD	MINIMUM	MAXIMUM	$/TONS
COK Coke	5.000	34,214	171,072			
TRANSFERS IN		-34,214				
TOTAL PRODUCTION (WEIGHT)		0	171,072			

HEATING VALUE EQUIVALENT BARRELS

* ESTIMATED FROM WEIGHT AND SPECIFIC GRAVITY

** POSITIVE INCR PROFIT IMPLIES INCENTIVE FOR INCREASED ACTIVITY

NIPER HEAVY OIL REFINING STUDY , CASE=FIVE00 3. 1. 1

MATERIAL AND ECONOMIC BALANCE

PRODUCTS (VOLUME BASIS)	$/BBL	BBL/CD	$/CD	MINIMUM	MAXIMUM	$/BBL
MUR Unleaded Regular	27.720	1,260,000	34,927,200		1,260,000	1.749
MUI Unleaded Midgrade		420,000		420,000	420,000	-26.575
MUP Unleaded Premium		420,000		420,000	420,000	-27.481
MBR Oxy Fuel+ Reform R		679,000		679,000	679,000	-26.422
MBP Oxy Fuel+ Reform P		452,000		452,000	452,000	-27.447
		-------	---------			
TOTAL GASOLINE		3,231,000	34,927,200			
AVG Aviation Gasoline		13,584		13,584	13,584	-28.414
		-------	---------			
TOTAL AV NAPHTHA		13,584				
JTA Aviation Jet Fuel		861,000		861,000	861,000	-26.646
KER Kerosene		18,567		18,567	18,567	-24.983
N2D Diesel	25.660	492,535	12,638,458		645,000	
N2O Heating Oil		727,000		727,000	727,000	-24.778
		-------	---------			
TOTAL DISTILLATE		2,099,102	12,638,458			
LS6 LOW Sulf FO <0.3%		32,000		32,000	32,000	-23.337
MS6 MED Sulf FO <1.0%		75,000		75,000	75,000	-19.926
HS6 HI Sulfur FO 3.0%	14.160	244,000	3,455,040	244,000	244,000	-3.305
		-------	---------			
TOTAL FUEL OIL		351,000	3,455,040			
LVN Petrochem Naphtha		104,814		104,814	104,814	-20.945
PCO Petrochem Other		109,000		109,000	109,000	-24.891
NPH Spec Naphtha		33,197		33,197	33,197	-20.957
LWX Lubes + Waxes		111,268		111,269	111,269	-25.697
ASP Asphalt		111,962		111,962	111,962	-15.969
BNZ Benzene		44,000		44,000	44,000	-56.569
TOL Toluene		26,000		26,000	26,000	-32.874
XYL Xylene		58,000		58,000	58,000	-60.517
LPG Liq Pet Gas	10.000	201,311	2,013,112		291,000	
		-------	---------			
TOTAL MISC.		799,552	2,013,112			
PGF#Plant Fuel Gas		201,987				
PRF#Resid Plant Fuel		3,000		3,000	3,000	-8.371
		-------	---------			
PLANT FUEL & FLARE		204,987				
LOS VOLUME LOSS		-252,552				
TRANSFERS OUT		161,713				
		-------	---------			
TOTAL PRODUCTION (VOLUME)		6,608,386	53,033,808			

NIPER HEAVY OIL REFINING STUDY , CASE=FIVE00 3. 2. 1

MATERIAL AND ECONOMIC BALANCE (CONTINUED)

FEEDS (VOLUME BASIS)	$/BBL	BBL/CD	$/CD	MINIMUM	MAXIMUM	$/BBL
JAY EAST LIGHT		5,000		5,000	5,000	23.282
CSM CUSHING SWEET		219,000		219,000	219,000	23.037
RWT WEST TEXAS INT		552,000		552,000	552,000	23.428
GIB LOUISIANA SWEET		1,180,000		1,180,000	1,180,000	23.995
BLV GULF COAST HVY		83,000		83,000	83,000	22.344
ANS Alaska North Slope		205,000		205,000	205,000	22.258
		-------	---------			
DOMESTIC CRUDE		2,244,000				
LOY CANADIAN BLEND		7,000		7,000	7,000	21.557
BCF SO. AMERICAN MED		1,144,000		1,144,000	1,144,000	21.451
B17 SO. AMERICAN HVY		139,000		139,000	139,000	20.601
ARL MIDDLE EAST		2,052,000		2,052,000	2,052,000	22.708
BON AFRICAN		493,000		493,000	493,000	23.902
BSX EUROPE		121,000		121,000	121,000	23.379
		-------	---------			
IMPORTS		3,956,000				
IC4 Iso Butane	-20.000	200,000	-4,000,000		200,000	3.619
NC4 Normal Butane	-18.000	131,309	-2,363,566		500,000	
MTL Methanol	-23.800	77,097	-1,834,900			
		-------	---------			
OTHER FEEDSTOCK		408,406	-8,198,466			
		-------	---------			
TOTAL FEEDSTOCKS (VOLUME)		6,608,406	-8,198,466			
			=========			
PRODUCTION MARGIN			44,835,342			

\# HEATING VALUE EQUIVALENT BARRELS

* ESTIMATED FROM VOLUME AND SPECIFIC GRAVITY

** POSITIVE INCR PROFIT IMPLIES INCENTIVE FOR INCREASED ACTIVITY

NIPER HEAVY OIL REFINING STUDY , CASE=FIVE00 4. 1. 1

UTILITIES PURCHASES AND SALES

		PURCHASES	COST	TOTAL	SALES	PRICE	TOTAL	INCR VAL
C82 CAT/CHEM	DOLLARS	1399,904	-1.210	-1693884				-1.210
FUL PLT FUEL	MM-BTU	1709,700	-1.850	-3162945				-1.850
H2O COOL H2O	M-GAL							-0.154
KWH ELECTRIC	KWH		-0.050					-0.033
PWR PWR GEN	KWH							-0.033
STM STEAM	M-LB							-2.492
TEL TEL	G-GL/BBL		-0.980					0.
SUL SULFUR	TONS				5,000	70.000	350,000	-70.000
WAT PROC H2O	M-GAL							-0.266
OXN OXYGEN	TONS		-100.000					0.
PPP POOL ERR	TOTAL		-10.000					-3.055
				======			======	
FINAL TOTAL				-4856829			350,000	

OVERALL ECONOMIC SUMMARY

		$/CD	M$/YR
FROM WEIGHT BASIS SUMMARY			
SALES	171,072		
PURCHASES			

NET	171,072		
FROM VOLUME BASIS SUMMARY			
SALES	53,033,808		
PURCHASES	-8,198,466		

NET	44,835,344		
GROSS OPERATING REVENUE		45006416	16427342
UTIL & MISC OPER COSTS		-4506829	-1644993
		--------	--------
NET OPERATING REVENUE		40499588	14782350
NEW EQUIPMENT EXPENSES			
MAINTENANCE	-97,513		
INS,TAX,OHD	-48,756		
FIXED OPER COST	-3,350		

TOTAL UNITS		-149,619	-54,611
		========	========
NET OPER PROFIT		40349968	14727739
CAPITAL RECOVERY			
UNITS		-549,793	-200,675
		--------	--------
TOTAL		-549,793	-200,675
		========	========
NET REVENUE		39800176	14527065

BONNER & MOORE PROJECT 3MS91-582

Appendix III

BONNER AND MOORE, UPDATE TO GULF COAST USING USING HIGHER SULFUR AND LOWER API GRAVITY CRUDE OIL

ATTACHMENT A

Following the same format presented in Volume I of the final report, our results of the economic impact of processing a heavier and more sour Gulf Coast (GC) incremental heavy crude oil in Regions 2 and 3, and 5 are attached.

- **Tables A-1** through **A-4** show a detailed breakdown by region of the additional investment required to process the GC crude quality change. As expected, the investment is centered in sulphur recovery, hydrogen production and transportation fuel quality equipment.

  Tables A-1 and **A-2** reflect the higher sulphur GC incremental under the "low" production rates. Details of the crude volumes are shown in **Table B-1**.

- **Tables A-3** and **A-4** reflect the results for the "high" production rate scenario. Details of the crude volumes for this particular case are shown in **Table B-2**. As a reminder, the incremental GC heavy crude oil production estimates for the years 1995 and 2000 are similar to the "low" case and, therefore, were not re-run.

- **Table A-5** shows a comparison of necessary investment between the high and low more heavier and sour incremental GC heavy oil production rate estimates as detailed in the previous tables.

  Refer to **Table 30** in Volume I of the final report where a similar comparison is shown with the GC heavy oil quality (19.5 API and 0.63% wt. sulphur) used through the initial study. The 203 million dollar investment cost difference in the year 2010 will increase by 36 million dollars if the GC incremental crude becomes heavier and more sour (18.2 API and 2.8% wt. sulphur).

- **Table A-6** through **A-9** details the new facilities (capacities and costs) necessary to process the GC heavy oil (18.2 API and 2.8% wt. sulphur) under the "high" production rate scenario.

SUMMARY OF LP MODEL RESULTS
LOW HEAVY OIL PRODUCTION

	Region 1						Regions 2 & 3				
	1990	1995	2000	2005	2010		1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD						**Refinery Crude Intake, MBCD**					
Domestic	13	9	4	0	0	Domestic	2,091	1,903	1,698	1,482	1,304
Imports	1,272	1,280	1,312	1,349	1,386	Imports	921	1,112	1,387	1,685	1,946
Total	**1,285**	**1,289**	**1,316**	**1,349**	**1,386**	**Total**	**3,012**	**3,015**	**3,085**	**3,167**	**3,250**
Calculated Gravity, API						**Calculated Gravity, API**					
Base Case	31.1	31.1	31.1	31.1	31.1	Base Case	34.5	34.5	34.5	34.5	34.5
New Heavy Oil	--	30.2	30.4	30.3	30.2	New Heavy Oil	--	35.0	34.6	34.2	33.8
Major Products, MBCD						**Major Products, MBCD**					
Gasoline	641	696	692	706	722	Gasoline	1,789	1,791	1,797	1,835	1,875
Light Distillate	91	111	118	128	138	Light Distillate	200	235	259	282	303
Middle Distillate	256	220	236	290	297	Middle Distillate	709	725	746	789	832
Fuel Oil	147	146	145	145	145	Fuel Oil	64	64	62	62	63
Capacity Added, MBCD						**Capacity Added, MBCD**					
Crude Distillation	--	4	31	65	101	Crude Distillation	--	27	97	179	262
Vacuum Distillation	--	17	27	48	67	Vacuum Distillation	--	44	97	155	216
Bottoms Conversion	--	0	0	11	17	Bottoms Conversion	--	1	31	60	87
Motor Fuel Quality	--	0	0	162	165	Motor Fuel Quality	--	0	0	226	288
Capital Investment, MM$	--	23	91	558	625	**Capital Investment, MM$**	--	60	253	898	1,085

TABLE A-1

SUMMARY OF LP MODEL RESULTS
LOW HEAVY OIL PRODUCTION

	Region 4				
	1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD					
Domestic	1,101	1,008	853	687	574
Imports	93	187	368	567	713
Total	1,194	1,195	1,221	1,254	1,287
Calculated Gravity, API					
Base Case	24.3	24.3	24.3	24.3	24.3
New Heavy Oil	--	24.1	23.7	23.3	24.7
Major Products, MBCD					
Gasoline	594	594	581	594	608
Light Distillate	170	211	225	245	265
Middle Distillate	225	207	210	222	233
Fuel Oil	165	159	159	161	162
Capacity Added, MBCD					
Crude Distillation	--	1	27	60	93
Vacuum Distillation	--	0	28	51	65
Bottoms Conversion	--	0	0	0	0
Motor Fuel Quality	--	0	0	110	124
Capital Investment, MM$	--	3	91	482	538

	Region 5				
	1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD					
Domestic	2,745	2,522	2,244	1,955	1,778
Imports	3,315	3,534	3,956	4,411	4,757
Total	6,060	6,056	6,200	6,366	6,535
Calculated Gravity, API					
Base Case	33.1	33.1	33.1	33.1	33.1
New Heavy Oil	--	32.7	32.5	32.2	31.9
Major Products, MBCD					
Gasoline	3,123	3,284	3,245	3,317	3,392
Light Distillate	668	823	880	957	1,031
Middle Distillate	1,260	1,132	1,219	1,451	1,531
Fuel Oil	362	351	351	354	357
Capacity Added, MBCD					
Crude Distillation	--	143	287	453	622
Vacuum Distillation	--	386	349	604	697
Bottoms Conversion	--	0	0	81	100
Motor Fuel Quality	--	300	310	1,032	1,142
Capital Investment, MM$	--	848	890	1,725	2,031

TABLE A-2

SUMMARY OF LP MODEL RESULTS
HIGH HEAVY OIL PRODUCTION
Years 2005 & 2010
(unless otherwise noted)

	Region 1 1990	1995	2000	2005	2010 (No Change)
Refinery Crude Intake, MBCD					
Domestic	13	9	4	0	0
Imports	1,272	1,280	1,312	1,349	1,386
Total	**1,285**	**1,289**	**1,316**	**1,349**	**1,386**
Calculated Gravity, API					
Base Case	31.1	31.1	31.1	31.1	31.1
New Heavy Oil	--	30.2	30.4	30.3	30.2
Major Products, MBCD					
Gasoline	641	696	692	706	722
Light Distillate	91	111	118	128	138
Middle Distillate	256	220	236	290	297
Fuel Oil	147	146	145	145	145
Capacity Added, MBCD					
Crude Distillation	--	4	31	65	101
Vacuum Distillation	--	17	27	48	67
Bottoms Conversion	--	0	0	11	17
Motor Fuel Quality	--	0	0	162	165
Capital Investment, MM$	--	23	91	558	625

	Regions 2 & 3 1990	1995	2000	2005	2010 (Only)
Refinery Crude Intake, MBCD					
Domestic	2,091	1,903	1,698	1,482	1,388
Imports	921	1,112	1,387	1,685	1,862
Total	**3,012**	**3,015**	**3,085**	**3,167**	**3,250**
Calculated Gravity, API					
Base Case	34.5	34.5	34.5	34.5	34.5
New Heavy Oil	--	35.0	34.6	34.2	33.5
Major Products, MBCD					
Gasoline	1,789	1,791	1,797	1,835	1,875
Light Distillate	200	235	259	282	303
Middle Distillate	709	725	746	789	832
Fuel Oil	64	64	62	62	63
Capacity Added, MBCD					
Crude Distillation	--	27	97	179	262
Vacuum Distillation	--	44	97	155	236
Bottoms Conversion	--	1	31	60	90
Motor Fuel Quality	--	0	0	226	296
Capital Investment, MM$	--	60	253	898	1,107

TABLE A-3

SUMMARY OF LP MODEL RESULTS
HIGH HEAVY OIL PRODUCTION
Years 2005 & 2010
(unless otherwise noted)

Region 4	1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD					
Domestic	1,101	1,008	853	732	708
Imports	93	187	368	522	579
Total	1,194	1,195	1,221	1,254	1,287
Calculated Gravity, API					
Base Case	24.3	24.3	24.3	24.3	24.3
New Heavy Oil	--	24.1	23.7	23.5	22.8
Major Products, MBCD					
Gasoline	594	594	581	594	608
Light Distillate	170	211	225	245	265
Middle Distillate	225	207	210	222	233
Fuel Oil	165	159	159	161	162
Capacity Added, MBCD					
Crude Distillation	--	1	27	60	93
Vacuum Distillation	--	0	28	65	109
Bottoms Conversion	--	0	0	0	11
Motor Fuel Quality	--	0	0	110	124
Capital Investment, MM$	--	3	91	488	616

Region 5	1990	1995	2000	2005	2010
Refinery Crude Intake, MBCD					
Domestic	2,745	2,522	2,244	2,034	2,058
Imports	3,315	3,534	3,956	4,332	4,477
Total	6,060	6,056	6,200	6,366	6,535
Calculated Gravity, API					
Base Case	33.1	33.1	33.1	33.1	33.1
New Heavy Oil	--	32.7	32.5	31.9	31.2
Major Products, MBCD					
Gasoline	3,123	3,284	3,245	3,317	3,392
Light Distillate	668	823	880	957	1,031
Middle Distillate	1,260	1,132	1,219	1,451	1,531
Fuel Oil	362	351	351	354	357
Capacity Added, MBCD					
Crude Distillation	--	143	287	453	622
Vacuum Distillation	--	386	349	497	667
Bottoms Conversion	--	0	0	67	162
Motor Fuel Quality	--	300	310	1,015	1,135
Capital Investment, MM$	--	848	890	1,742	2,090

TABLE A-4

TOTAL INVESTMENT OF FACILITIES
ALTERNATE HIGH VS LOW PRODUCTION RATES
(MM $)

	--------- 2005 ---------			--------- 2010 ---------		
Proposed Region	**High**	**Low**		**High**	**Low**	
1	558	558	--	625	625	--
2 & 3	**898**	**892**	**6**	**1,107**	**1,085**	**22**
4	488	482	6	616	538	78
5	**1,742**	**1,725**	**17**	**2,090**	**2,031**	**59**
6	418	417	1	454	425	29
7	--	--	--	--	--	--
9	2,043	2,026	17	2,063	2,012	51
8 & 10	371	371	--	408	408	--
Total	6,518	6,471	47	7,363	7,124	239

TABLE A-5

DETAILS OF LP NEW FACILITIES
HIGH HEAVY OIL PRODUCTION

REGION 1 (No Change from Low Basis)

	MBCD 1995	MBCD 2000	MBCD 2005	MBCD 2010		MM$ 1995	MM$ 2000	MM$ 2005	MM$ 2010
Crude Distillation	4.0	31.0	65.0	101.0	Crude Distillation	6.9	26.2	42.5	56.5
Vacuum Distillation	17.1	27.2	48.0	67.5	Vacuum Distillation	16.5	23.4	35.8	46.2
Coking	--	--	10.9	17.4	Coking	--	--	22.6	35.8
Oxygenates	--	--	162.3	165.3	Oxygenates	--	--	352.0	355.8
Isomerization	--	--	--	--	Isomerization	--	--	--	--
Cat Cracking	--	--	--	--	Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--	Hydrocracking	--	--	--	--
Alkylation	--	--	--	--	Alkylation	--	--	--	--
Hydrotreating	--	--	--	--	Hydrotreating	--	--	--	--
Plant Utilities	--	--	--	--	Plant Utilities	--	41.8	105.4	131.0
						23.4	**91.4**	**558.3**	**625.3**

REGION 2 & 3 (Years 2005 & 2010)

	MBCD 1995	MBCD 2000	MBCD 2005	MBCD 2010		MM$ 1995	MM$ 2000	MM$ 2005	MM$ 2010
Crude Distillation	27.0	97.0	179.0	262.0	Crude Distillation	24.0	55.1	82.0	105.1
Vacuum Distillation	43.9	96.6	155.3	235.7	Vacuum Distillation	33.4	60.5	86.4	118.1
Coking	0.3	31.2	60.3	90.2	Coking	2.2	44.7	68.7	89.2
Oxygenates	--	--	226.0	295.6	Oxygenates	--	--	452.0	528.4
Isomerization	--	--	--	--	Isomerization	--	--	--	--
Cat Cracking	--	--	--	--	Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--	Hydrocracking	--	--	--	--
Alkylation	--	--	--	--	Alkylation	--	--	--	--
Hydrotreating	--	--	--	--	Hydrotreating	--	--	--	--
Plant Utilities	--	--	--	--	Plant Utilities	--	92.8	208.6	266.3
						59.6	**253.1**	**897.7**	**1,107.1**

TABLE A-6

DETAILS OF LP NEW FACILITIES
HIGH HEAVY OIL PRODUCTION

REGION 4 (Years 2005 & 2010)

	MBCD					MM$			
	1995	2000	2005	2010		1995	2000	2005	2010
Crude Distillation	1.0	27.0	60.0	93.0	Crude Distillation	2.8	24.0	40.3	53.6
Vacuum Distillation	--	28.1	65.1	108.8	Vacuum Distillation	--	24.0	45.0	66.1
Coking	--	--	--	11.3	Coking	--	--	--	52.2
Oxygenates	--	--	110.5	124.0	Oxygenates	--	--	296.9	315.7
Isomerization	--	--	--	--	Isomerization	--	--	--	--
Cat Cracking	--	--	--	--	Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--	Hydrocracking	--	--	--	--
Alkylation	--	--	--	--	Alkylation	--	--	--	--
Hydrotreating	--	--	--	--	Hydrotreating	--	--	--	--
Plant Utilities	--	--	--	--	Plant Utilities	--	42.5	105.6	128.6
						2.8	**90.5**	**487.8**	**616.2**

REGION 5 (Years 2005 & 2010)

Crude Distillation	143.0	287.0	453.0	622.0	Crude Distillation	70.9	111.5	150.0	184.3
Vacuum Distillation	386.0	349.4	497.0	667.4	Vacuum Distillation	171.0	158.7	206.7	257.8
Coking	--	--	66.8	161.5	Coking	--	--	73.4	130.2
Oxygenates	299.6	309.8	1,014.8	1,135.1	Oxygenates	510.7	521.1	1,086.2	1,175.1
Isomerization	--	--	--	--	Isomerization	--	--	--	--
Cat Cracking	--	--	--	--	Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--	Hydrocracking	--	--	--	--
Alkylation	--	--	--	--	Alkylation	--	--	--	--
Hydrotreating	--	--	--	--	Hydrotreating	--	--	--	--
Plant Utilities	--	--	--	--	Plant Utilities	95.1	98.6	225.2	342.2
						847.7	**889.9**	**1,741.8**	**2,089.6**

TABLE A-7

DETAILS OF LP NEW FACILITIES
HIGH HEAVY OIL PRODUCTION

REGION 6 (Years 2005 & 2010)

	MBCD					MM$			
	1995	2000	2005	2010		1995	2000	2005	2010
Crude Distillation	36.0	46.0	57.0	71.0	Crude Distillation	28.9	33.9	39.0	45.0
Vacuum Distillation	43.8	51.8	62.4	75.8	Vacuum Distillation	33.4	37.9	43.6	50.4
Coking	18.7	21.1	25.8	30.5	Coking	94.6	101.7	114.5	127.4
Oxygenates	--	--	--	--	Oxygenates	--	--	--	--
Isomerization	38.0	38.0	35.7	34.0	Isomerization	100.1	103.7	133.8	102.4
Cat Cracking	--	--	--	--	Cat Cracking	--	--	--	--
Hydrocracking	--	--	--	--	Hydrocracking	--	--	--	--
Alkylation	6.9	7.5	7.7	7.6	Alkylation	12.9	13.7	13.9	13.7
Hydrotreating	--	--	--	--	Hydrotreating	--	--	--	--
Plant Utilities	--	--	--	--	Plant Utilities	30.8	41.1	73.1	114.7
						300.7	**332.0**	**417.9**	**453.6**

REGION 9 (Years 2005 & 2010)

	MBCD					MM$			
	1995	2000	2005	2010		1995	2000	2005	2010
Crude Distillation	199.0	224.0	252.0	281.0	Crude Distillation	87.9	94.9	102.4	110.0
Vacuum Distillation	160.2	202.8	244.3	275.5	Vacuum Distillation	88.4	105.5	121.3	132.8
Coking	--	--	--	--	Coking	--	--	--	--
Oxygenates	165.9	119.0	346.7	370.8	Oxygenates	374.9	343.4	591.9	622.3
Isomerization	46.1	42.9	39.6	--	Isomerization	69.4	104.9	101.1	--
Cat Cracking	117.1	89.4	65.0	121.3	Cat Cracking	263.7	221.2	179.7	269.9
Hydrocracking	--	63.1	110.9	93.4	Hydrocracking	--	225.4	321.3	288.5
Alkylation	30.7	23.0	106.1	98.9	Alkylation	39.3	93.4	263.4	251.2
Hydrotreating	--	--	--	13.9	Hydrotreating	--	--	--	20.2
Plant Utilities	--	--	--	--	Plant Utilities	51.9	322.4	362.3	368.0
						975.5	**1,511.1**	**2,043.4**	**2,062.9**

TABLE A-8

DETAILS OF LP NEW FACILITIES
HIGH HEAVY OIL PRODUCTION

REGION 8 & 10 (No Change from Low Basis)

	MBCD			
	1995	**2000**	**2005**	**2010**
Crude Distillation	1.0	1.0	7.0	9.0
Vacuum Distillation	--	3.0	16.2	21.6
Coking	--	--	--	--
Oxygenates	--	1.1	11.7	16.6
Isomerization	--	--	1.4	--
Cat Cracking	8.2	8.7	8.8	6.4
Hydrocracking	4.1	8.9	17.7	22.8
Alkylation	1.7	3.3	6.6	6.5
Hydrotreating	14.4	3.8	--	--
Plant Utilities	--	--	--	--

	MM$			
	1995	**2000**	**2005**	**2010**
Crude Distillation	2.8	2.8	10.0	11.7
Vacuum Distillation	--	4.5	15.9	19.7
Coking	--	--	--	--
Oxygenates	--	11.8	70.5	87.5
Isomerization	--	--	9.0	--
Cat Cracking	46.7	48.5	48.8	39.6
Hydrocracking	40.5	65.7	101.3	119.0
Alkylation	16.0	23.6	39.9	39.5
Hydrotreating	24.3	10.9	--	--
Plant Utilities	47.0	59.1	75.9	91.2
	177.3	**226.9**	**371.3**	**408.2**

TABLE A-9

ATTACHMENT B

For the purpose of clarification, we have detailed the crude quality breakdown as it affects the intake for the LP regional models. **Tables B-1** and **B-2** show the forecasted incremental Gulf Coast (GC) heavy crude oil for Regions 2 and 3, and 5. These are the chosen regions by NIPER to study the effects on capital investments if the (**incremental**) crude is of 18.2 API gravity and 2.5% wt. sulphur. The quality for this GC crude in our initial analysis (**base**) is 19.5 API and 0.63% wt. sulphur.

We can refer to **Tables 4** through **9** in Volume I of the final report and compare the regional crude quality breakdown in the attached **Table B-1**. Total regional volumes remain the same.

LOW PRODUCTION RATES
CRUDE REPRESENTATION FOR LP MODELS

Year	Gulf Coast (GC) Heavy Oil	Regional Distribution 2 & 3	5	Total
1990	Base	15	49	64
1995	Base	15	49	64
	Increment	3	8	11
	Total	18	57	75
2000	Base	15	49	64
	Increment	11	34	45
	Total	26	83	109
2005	Base	15	49	64
	Increment	23	73	96
	Total	38	122	160
2010	Base	15	49	64
	Increment	46	151	197
	Total	61	200	261

	GC Heavy Oil API	% Wt. S
Base	19.5	0.63
Increment	18.2	2.8

TABLE B-1

HIGH PRODUCTION RATES
CRUDE REPRESENTATION FOR LP MODELS

Year	Incremental Gulf Coast (GC) Heavy Oil	Regional Distribution 2 & 3	5	Total
2005	Base	15	49	64
	Increment	46	152	198
	Total	61	201	262
2010	Base	15	49	64
	Increment	130	425	555
	Total	145	474	619

	GC Heavy Oil API	% Wt. S
Base	19.5	0.63
Increment	18.2	2.8

TABLE B-2

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